PRESS RELEASE

Canadian Natural

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2009 FOURTH QUARTER AND YEAR END RESULTS CALGARY, ALBERTA – MARCH 4, 2010 – FOR IMMEDIATE RELEASE

Commenting on the fourth quarter 2009 and year end results, Allan Markin, Chairman of Canadian Natural Resources Limited ("Canadian Natural" or the "Company") stated, "Canadian Natural's strong quarterly and annual results reflect the focus of management and all employees to deliver on the defined plan. We were proactive in our approach to the low crude oil and natural gas pricing environment by deferring capital in our original 2009 budget. Our capital discipline provides balance sheet strength throughout all business cycles. Last year was noteworthy for Canadian Natural as our diligent efforts were rewarded with the achievement of first oil at Horizon, helping 2009 become a record crude oil production year for the Company. We continue to strive to develop our assets in the most cost effective way and are committed to providing long-term shareholder value."

Canadian Natural's Vice-Chairman, John Langille, continued, "The commodity price environment in 2009 was challenging, particularly in the first half of the year, as a result of economic concerns that continued from 2008. By maintaining capital and operating discipline in 2009, we were able to elevate the Company's financial strength. Debt to book capitalization exited 2009 at 33%, below current targeted ranges. We understand the importance of a strong balance sheet as it enables the Company to withstand commodity price cycles and provides the flexibility to take advantage of current and future opportunities. As well, in recognition of our strong financial position, large production base and sustainable cash flow, the Company has approved a 43% dividend increase to $0.15 per quarter per common share payable April 1, 2010."

Steve Laut, President of Canadian Natural concluded, "As always we focus our capital on projects that provide the greatest value and highest returns affording us the ability to generate significant free cash flow. We continue to progress our thermal crude oil growth plan and target to sanction the Kirby In-Situ Oil Sands Project by the end of 2010. At Horizon, we continue to focus on reaching sustainable production volumes, increasing reliability and reducing operating costs. Additionally, we continue engineering and procurement for Tranche 2 of the Phase 2/3 expansion. We are committed to completing lessons learned from the construction of Phase 1 to ensure an optimal strategy for the development of future expansions.

The Company had another solid year of adding new reserves with finding and on-stream costs (excluding Horizon SCO) of $19.81 per barrel of oil equivalent for proved reserves and $22.64 per barrel of oil equivalent for proved and probable reserves utilizing the new SEC commodity pricing assumptions. The significant reduction in natural gas pricing in 2009 resulted in the loss of late-life reserves and certain reserves associated with undeveloped drilling opportunities. The significant increase in crude oil prices resulted in calculated higher royalties and accelerated project payouts for oil sand projects, including Horizon and our thermal projects. While this improves the economics of the projects it also results in reduced net reserves. Excluding the impact of price revisions, our finding and on-stream costs would have been $12.28 per barrel of oil equivalent for proved reserves and $7.74 per barrel of oil equivalent for proved and probable reserves."

QUARTERLY HIGHLIGHTS

($ millions, except as noted)	Quarterly Results **Dec 31 2009**	 Sep 30 2009	 Dec 31 2008	Year End Results **Dec 31 2009**	 Dec 31 2008
Net earnings	**$ 455**	$ 658	$ 1,770	**$ 1,580**	$ 4,985
per common share, basic and diluted	**$ 0.85**	$ 1.21	$ 3.27	**$ 2.92**	$ 9.22
Adjusted net earnings from operations (1)	**$ 667**	$ 658	$ 697	**$ 2,689**	$ 3,492
per common share, basic and diluted	**$ 1.23**	$ 1.21	$ 1.29	**$ 4.96**	$ 6.46
Cash flow from operations (2)	**$ 1,703**	$ 1,506	$ 1,570	**$ 6,090**	$ 6,969
per common share, basic and diluted	**$ 3.14**	$ 2.78	$ 2.90	**$ 11.24**	$ 12.89
Capital expenditures, net of dispositions	**$ 694**	$ 574	$ 1,827	**$ 2,997**	$ 7,451
Daily production, before royalties					
Natural gas (mmcf/d)	**1,250**	1,293	1,427	**1,315**	1,495
Crude oil and NGLs (bbl/d)	**366,451**	359,269	309,570	**355,463**	315,667
Equivalent production (boe/d)	**574,857**	574,755	547,399	**574,730**	564,845

(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.

Annual

- The Company's natural gas assets delivered as expected, averaging 1,315 mmcf/d for 2009, a decrease of 12% from 2008. As anticipated, 2009 natural gas production volumes declined due to reduced capital re-investment and an associated 59% reduction in natural gas net drilling activity.

- Total crude oil and NGLs production in 2009 averaged 355,463 bbl/d, a 13% increase from 2008. Crude oil volumes were higher due to capital reallocation to crude oil drilling and the commencement of production at Horizon Oil Sands ("Horizon"), slightly offset by lower NGLs production and international light crude oil declines.

- Cash flow from operations decreased 13% to $6.1 billion in 2009 from $7.0 billion in 2008, and net earnings decreased 68% in 2009 to $1.6 billion from $5.0 billion in 2008. The decrease in cash flow and earnings was primarily due to a decrease in product pricing, partially offset by the commencement of production at Horizon.

Fourth Quarter

- Total crude oil and NGLs production for Q4/09 was 366,451 bbl/d. Q4/09 crude oil production volumes increased 2% from Q3/09 of 359,269 bbl/d, and increased 18% from Q4/08 of 309,570 bbl/d. The increase in volumes in Q4/09 from the same quarter last year was primarily due to production at Horizon. The increase from Q3/09 reflects increased production at Horizon and higher thermal volumes relating to the cyclic nature of the Company's thermal production.

- Natural gas production volumes for the fourth quarter represented 36% of the Company's total production. Natural gas production for Q4/09 averaged 1,250 mmcf/d, down 3% from 1,293 mmcf/d for Q3/09 and down 12% from 1,427 mmcf/d for Q4/08 as expected. The decrease in volumes for Q4/09 from Q4/08 reflected the reallocation of capital towards higher return crude oil projects.

- Quarterly cash flow from operations was approximately $1.7 billion, a 13% increase from Q3/09 and an increase of 8% from Q4/08. The increase from Q3/09 primarily reflected higher crude oil and natural gas price realizations, partially offset by a lower realized risk management gain for the quarter. The increase from Q4/08 reflects the impact of higher realized crude oil pricing, narrowing heavy oil differentials, and higher volumes primarily associated with production at Horizon. These factors were partially offset by the impact of lower natural gas volumes and pricing.

- Quarterly net earnings for Q4/09 of $455 million included the effects of unrealized risk management activity, stock based compensation and fluctuations in foreign exchange. Excluding these items, quarterly adjusted net earnings from operations for Q4/09 were $667 million, a decrease of 4% from Q4/08.

Operational and Financial

- Maintained a strong undeveloped conventional core land base in Canada of 10.5 million net acres - a key asset for continued value growth.

- Completed the Q4/09 North America drilling program targeting 212 net crude oil wells and 28 net natural gas wells with a 93% success rate in the quarter, excluding stratigraphic test and service wells. The success rate is a reflection of Canadian Natural's strong, predictable, low-risk asset base.

- Improvements at Pelican Lake continue with the conversion of waterflood wells to polymer flood wells, with production averaging approximately 38,000 bbl/d, a 2% increase over the previous quarter.

- Q4/09 North America crude oil and NGLs production increased 3% from Q3/09 levels, reflecting the transition between steam and production cycles of Primrose wells.

- Diagnostic steaming is proceeding according to plan at Primrose East and average production is targeted to be between 16,000 bbl/d and 20,000 bbl/d in 2010 as we cautiously return to normal steaming activities.

- The Facility Upgrade Project at Espoir, which will increase capacity of the Floating Production Storage and Offtake vessel ("FPSO"), is progressing and commissioning is targeted to be complete in the second quarter of 2010.

- At the Olowi Project in Offshore Gabon production volumes from the first platform continue to be below expectations and as a result the Company recognized a ceiling test impairment of $115 million (pre-tax) at December 31, 2009. The Company continues drilling at the next scheduled platform with production targeted for second quarter of 2010.

- Independent qualified reserves evaluators evaluated and reviewed all of the Company's crude oil and natural gas reserves under twelve month average prices and current costs as at December 31, 2009:

  - Total corporate proved reserves were 3.03 billion barrels of crude oil and NGLs and 3.18 trillion cubic feet of natural gas equating to 3.56 billion barrels of oil equivalent. Total corporate proved and probable reserves were 4.74 billion barrels of crude oil and NGLs and 4.21 trillion cubic feet of natural gas equating to 5.44 billion barrels of oil equivalent.

  - As a result of the changes to United States Securities Exchange Commission ("SEC") regulations, the synthetic crude oil ("SCO") produced at Horizon is now considered a crude oil and natural gas producing activity and is therefore included with crude oil and NGL reserves.

  - Horizon net proved SCO reserves decreased by 296 million barrels to 1.65 billion barrels. The decrease included an economic revision due to price of 307 million barrels. The net proved and probable SCO reserves were 2.51 billion barrels. The significant increase in crude oil prices resulted in calculated higher royalties and accelerated project payout.

  - Total net proved reserves excluding Horizon SCO at the end of 2009 amounted to 1.38 billion barrels of crude oil and NGLs and 3.18 trillion cubic feet of natural gas equating to 1.91 billion barrels of oil equivalent. Total net proved reserves excluding Horizon SCO decreased by 53 million barrels of oil equivalent from 2008. As a direct result of lower natural gas prices, there was a reduction of net proved natural gas reserves of 327 billion cubic feet. There was also a decrease of 19 million barrels of proved crude oil and NGLs as a result of economic revisions due to higher royalties and accelerated project payouts resulting from higher crude oil prices.

  - Total net proved reserve additions excluding Horizon SCO equaled 69% of 2009 net production, at a finding and on-stream cost of $19.81 per barrel of oil equivalent. The Company's three-year average proved finding and on-stream cost was $17.76 per barrel of oil equivalent.

- Total net proved and probable reserves, excluding Horizon SCO, at the end of 2009 amounted to 2.23 billion barrels of crude oil and NGLs and 4.21 trillion cubic feet of natural gas equating to 2.93 billion barrels of oil equivalent. Total proved and probable net reserves, excluding Horizon SCO, decreased by 69 million barrels of oil equivalent from 2008 as a result of economic revisions due to prices.

- Total net proved and probable reserve additions, excluding Horizon SCO, equaled 61% of 2009 net production, at a finding and on-stream cost of $22.64 per barrel of oil equivalent. The Company's three-year average net proved and probable finding and on-stream cost was $17.41 per barrel of oil equivalent.

- North America net proved reserve additions excluding economic revisions due to prices and Horizon SCO equaled 176% of 2009 production at a finding and on-stream cost of $6.45 per barrel of oil equivalent. Net proved and probable reserve additions excluding economic revisions due to prices and Horizon SCO equaled 213% of 2009 production at a finding and on-stream cost of $5.32 per barrel of oil equivalent.

- Using the total net proved finding and on-stream costs, excluding Horizon SCO, the Company achieved an overall recycle ratio of 1.4x during 2009. By also excluding the revisions due to prices, the recycle ratio would be 2.3x.

▪ Long-term debt was reduced by $3.3 billion to $9.7 billion in 2009 from $13.0 billion in 2008. As a result, 2009 debt to book capitalization improved to 33% (2008 - 41%) and debt to EBITDA improved to 1.4x (2008 - 1.7x).

▪ Tenth consecutive year of dividend increases. The 2010 quarterly dividend on common shares increased by 43% to C$0.15 from C$0.105 per common share, payable April 1, 2010.

▪ On March 3, 2010 the Board of Directors approved a resolution to file with the Toronto Stock Exchange a Notice of Intention to purchase by way of normal course issuer bid up to 2.5% of its issued and outstanding common shares. Subject to acceptance by the Toronto Stock Exchange of the Notice of Intention, the purchases would be made through the facilities of the Toronto Stock Exchange and the New York Stock Exchange.

▪ On March 3, 2010, the Company's Board of Directors approved a resolution to subdivide the Company's common shares on a two for one basis, subject to shareholder approval. The proposal will be voted on at the Company's Annual and Special Meeting of Shareholders to be held on May 6, 2010.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

In order to facilitate efficient operations, Canadian Natural focuses its activities in core regions where it can dominate the land base and infrastructure. Undeveloped land is critical to the Company's ongoing growth and development within these core regions. Land inventories are maintained to enable continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By dominating 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; namely natural gas, light/medium crude oil, heavy crude oil, synthetic crude oil and NGLs. A large diversified project portfolio enables the effective allocation of capital to higher return opportunities.

OPERATIONS REVIEW

Activity by core region

	Net undeveloped land as at Dec 31, 2009 (thousands of net acres)	**Drilling activity year ended Dec 31, 2009 (net wells) (1)**
North America conventional		
Northeast British Columbia	**2,068**	**21.5**
Northwest Alberta	**1,154**	**53.5**
Northern Plains	**5,885**	**599.9**
Southern Plains	**804**	**19.0**
Southeast Saskatchewan	**139**	**22.5**
Thermal In-situ Oil Sands	**486**	**289.0**
	10,536	**1,005.4**
Oil Sands Mining and Upgrading	**115**	**115.0**
North Sea	**150**	**1.2**
Offshore West Africa	**192**	**6.1**
	10,993	**1,127.7**

(1) Drilling activity includes stratigraphic test and service wells.

Drilling activity (number of wells)

	Year Ended Dec 31			
	2009		2008	
	Gross	**Net**	Gross	Net
Crude oil	**686**	**644**	728	682
Natural gas	**141**	**109**	411	269
Dry	**49**	**46**	44	39
Subtotal	**876**	**799**	1,183	990
Stratigraphic test / service wells	**329**	**329**	133	131
Total	**1,205**	**1,128**	1,316	1,121
Success rate (excluding stratigraphic test / service wells)		**94%**		96%

North America Conventional

North America natural gas

	Three Months Ended			Year Ended	
	Dec 31 2009	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Natural gas production (mmcf/d)	**1,218**	1,264	1,405	**1,287**	1,472
Net wells targeting natural gas	**28**	17	43	**117**	280
Net successful wells drilled	**28**	17	41	**109**	269
Success rate	**100%**	100%	95%	**93%**	96%

- Annual production for North America natural gas in 2009 was 1,287 mmcf/d, a decrease of 13% from 2008. Q4/09 North America natural gas production decreased 4% from Q3/09 and decreased 13% from Q4/08. The year over year decrease reflected natural declines in production due to the Company's strategic decision to reduce spending on natural gas drilling and focus on higher return crude oil projects.
- Canadian Natural targeted 28 net natural gas wells in Q4/09. In Northeast British Columbia, 4 net wells were drilled, while in Northwest Alberta, 12 net wells were drilled. In the Northern Plains, 11 net wells were drilled, with 1 net well drilled in the Southern Plains.
- Planned drilling activity for Q1/10 includes 47 net natural gas wells compared to drilling activity for Q1/09 of 72 net natural gas wells.

North America crude oil and NGLs

	Three Months Ended			Year Ended	
	Dec 31 2009	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Crude oil and NGLs production (bbl/d)	**229,206**	223,307	240,831	**234,523**	243,826
Net wells targeting crude oil	**212**	270	190	**676**	704
Net successful wells drilled	**195**	260	181	**638**	677
Success rate	**92%**	96%	95%	**94%**	96%

- Annual production for North America crude oil and NGLs in 2009 was 234,523 bbl/d, a decrease of 4% from 2008 production. Q4/09 North America crude oil and NGLs production increased 3% from Q3/09 and decreased 5% from Q4/08 levels. The increase from the previous quarter reflects higher thermal production volumes at Primrose.
- Diagnostic steaming is proceeding according to plan at Primrose East and average production is targeted to be between 16,000 bbl/d and 20,000 bbl/d in 2010 as the Company cautiously returns to normal steaming activities.
- In early 2007, Canadian Natural announced the Kirby In-Situ Oil Sands Project, the proposed third phase of the thermal growth plan which will target production capacity of 45,000 bbl/d. The Company has filed its formal regulatory application documents for this project, which is still proceeding, as part of the Company's normal course of business. The Company continues with detailed engineering and design work and targets to sanction the project by the end of 2010.

- Development of new pads and tertiary recovery conversion projects at Pelican Lake continued as expected throughout Q4/09. The Company drilled 60 horizontal wells in 2009 with plans to drill an additional 148 horizontal wells in 2010. Pelican Lake production averaged approximately 38,000 bbl/d for Q4/09 compared to approximately 37,000 bbl/d for Q3/09 and Q4/08. The response from the polymer flood project continues to be positive and the Company is converting regions currently under waterflood to polymer flood and is also expanding the polymer flood to new areas.

- Conventional heavy crude oil production volumes were slightly higher in Q4/09 compared to Q3/09 reflecting the expanded drilling program in 2009.

- During Q4/09, drilling activity targeted 212 net crude oil wells including 159 wells targeting heavy crude oil, 19 wells targeting Pelican Lake crude oil, 14 wells targeting thermal crude oil and 20 wells targeting light crude oil.

- Planned drilling activity for Q1/10 includes 253 net crude oil wells, excluding stratigraphic test and service wells.

International

	Three Months Ended			Year Ended	
	Dec 31 2009	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Crude oil production (bbl/d)					
North Sea	**34,408**	34,034	42,991	**37,761**	45,274
Offshore West Africa	**32,643**	35,021	25,748	**32,929**	26,567
Natural gas production (mmcf/d)					
North Sea	**12**	8	10	**10**	10
Offshore West Africa	**20**	21	12	**18**	13
Net wells drilled	**-**	2.2	1.1	**6.4**	5.5
Net successful wells drilled	**-**	1.9	1.1	**6.1**	4.7
Success rate	**-**	86%	100%	**95%**	85%

North Sea

- North Sea production was 34,408 bbl/d during the quarter, in line with expectations and quarterly guidance. Both Q3/09 and Q4/09 were impacted by planned maintenance shutdowns which were completed within anticipated time frames. On an annual basis North Sea production was 37,761 bbl/d, a 17% decrease from 2008 as expected, reflecting reduced activity levels and natural declines.

Offshore West Africa

- In Q4/09, crude oil production at Offshore West Africa was at the high end of guidance at 32,643 bbl/d despite a well failure at Espoir late Q4/09. Strategies to remediate the well failure are currently under review. On an annual basis, Offshore West Africa crude oil production increased by 24% from the prior year, reflecting additional volumes from the Baobab drilling program and Olowi, offsetting expected declines at Espoir.

- The Facility Upgrade Project at Espoir, which will increase capacity of the FPSO, is progressing and commissioning is targeted to be complete in the second quarter of 2010.

- At the Olowi Project in Offshore Gabon, production volumes from the first platform continue to be below expectations and as a result the Company recognized a ceiling test impairment of $115 million (pre-tax) at December 31, 2009. The Company continues drilling at the next scheduled platform with production targeted for the second quarter of 2010.

Oil Sands Mining and Upgrading

	Three Months Ended			Year Ended	
	Dec 31 2009	Sep 30 2009	Dec 30 2008	**Dec 31 2009**	Dec 31 2008
Synthetic Crude Oil Production (bbl/d)	**70,194**	66,907	-	**50,250**	-

- Equipment reliability challenges in the Hydrogen plant and downtime relating to a Coker furnace caused an extended shut down at the end of Q4/09. As a result, December production was approximately 42,000 bbl/d SCO decreasing overall quarterly production to the low end of guidance. Horizon's operational ability at design capacity was proven in Q4/09 as a record monthly average production was reached in November at approximately 97,000 bbl/d SCO. Monthly average production for Horizon will be provided on a monthly basis on the Company's website.

Recent monthly production is as follows:

Approximate monthly production	October 2009	November 2009	December 2009	January 2010
(bbl/d SCO)	71,000	97,000	42,000	72,000

- The Company continues to ramp up to sustainable production of 110,000 bbl/d which is targeted for mid-2010.
- The Company has been able to rectify the impact of clays content through ore blending from three mine benches. Mitigating strategies such as stockpiling the second bench allowed access to the third bench much sooner than originally anticipated.
- Engineering and procurement for Tranche 2 of the Phase 2/3 expansion is progressing with a focus on increasing reliability and uptime. Tranches 3 and 4 of Phase 2/3 continue to be re-profiled. The Company continues to work on completing its lessons learned from the construction of Phase 1 and implementing these into the development of future expansions.
- In the 2009 start-up year and without the benefit of targeted full production capacity, the annual operating cost averaged approximately C$39.89 per barrel of SCO. With the stabilization of production during 2010, the Company is targeting to reduce these costs to C$31.00 to C$37.00 per barrel of SCO.

MARKETING

	Three Months Ended			Year Ended	
	Dec 31 2009	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Crude oil and NGLs pricing					
WTI [1] benchmark price (US$/bbl)	**$ 76.17**	$ 68.29	$ 58.75	**$ 61.93**	$ 99.65
Western Canadian Select blend differential from WTI (%)	**16%**	15%	33%	**16%**	20%
SCO price (US$/bbl)	**$ 75.07**	$ 67.20	$ 58.64	**$ 61.51**	$ 102.48
Corporate average pricing before risk management (C$/bbl)	**$ 68.00**	$ 62.90	$ 45.81	**$ 57.68**	$ 82.41
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 4.01**	$ 2.87	$ 6.43	**$ 3.91**	$ 7.71
Corporate average pricing before risk management (C$/mcf)	**$ 4.75**	$ 3.80	$ 7.03	**$ 4.53**	$ 8.39

(1) Refers to West Texas Intermediate (WTI) crude oil barrel priced at Cushing, Oklahoma.

- In Q4/09, the Western Canadian Select ("WCS") heavy crude oil differential as a percent of WTI was 16%, compared to 15% in Q3/09. Heavy crude oil differentials remained narrow in Q4/09 due to continuing demand from the US refineries for heavy crude oil.

- During Q4/09, the Company allocated approximately 140,000 bbl/d of its heavy crude oil blends to the WCS blend, optimizing the pricing for heavy crude oil. WCS continues its advancement as the recognized heavy crude oil benchmark for North America.
- Natural gas pricing for Q4/09 remained relatively weak primarily due to supply/demand imbalances. North America natural gas inventory levels remained high during the fourth quarter due to an oversupply from US producers and lower industrial consumption.
- In the first quarter of 2010, Canadian Natural announced, together with North West Upgrading Inc., the submission of a joint proposal to the Alberta Government to construct and operate a bitumen refinery near Redwater, Alberta. This proposal was submitted in response to a request for proposal under the Alberta Royalty Framework's Bitumen Royalty In Kind (BRIK) program.

FINANCIAL REVIEW

- Although the negative worldwide economic conditions appear to be subsiding, the potential for continued volatility in the market and a long road to full economic recovery remain. The Company continually examines its liquidity position and ensures a low risk approach to finance. The Company understands the potential for commodity price declines and positions itself to endure and succeed in these times. The Company's financial strength continues to improve as an increase in production and free cash flow are expected in 2010. Financial strengths continue to be:
  - A diverse asset base spread over various commodity types with 94% of production located in G8 countries.
  - Financial stability and liquidity - cash flow from operations of $1.7 billion for Q4/09, with available unused bank lines of $2.0 billion at December 31, 2009.
  - Flexibility in asset base allowing for disciplined capital allocations.
- A strengthening balance sheet with debt to book capitalization of 33% and debt to EBITDA of 1.4 times, both below targeted ranges. Long-term debt was reduced to $9.7 billion as at December 31, 2009, a reduction of $3.3 billion over the previous year.
- Tenth consecutive year of dividend increases. The 2010 quarterly dividend on common shares increased by 43% to C$0.15 from C$0.105 per common share, payable April 1, 2010.
- On March 3, 2010 the Board of Directors approved a resolution to file with the Toronto Stock Exchange a Notice of Intention to purchase by way of normal course issuer bid up to 2.5% of its issued and outstanding common shares. Subject to acceptance by the Toronto Stock Exchange of the Notice of Intention, the purchases would be made through the facilities of the Toronto Stock Exchange and the New York Stock Exchange.
- On March 3, 2010, the Company's Board of Directors approved a resolution to subdivide the Company's common shares on a two for one basis, subject to shareholder approval. The proposal will be voted on at the Company's Annual and Special Meeting of Shareholders to be held on May 6, 2010.

OUTLOOK

- The Company forecasts 2010 production levels before royalties to average between 1,117 and 1,185 mmcf/d of natural gas and between 400,000 and 445,000 bbl/d of crude oil and NGLs. Q1/10 production guidance before royalties is forecast to average between 1,197 and 1,221 mmcf/d of natural gas and between 372,000 and 409,000 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 http://www.cnrl.com/investor_info/corporate_guidance/.

YEAR-END RESERVES

Determination of reserves

For the year ended December 31, 2009 the Company retained qualified independent reserves evaluators, Sproule Associates Limited ("Sproule"), and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company's proved, as well as probable crude oil, synthetic crude oil, NGLs and natural gas reserves and prepare Evaluation Reports on these reserves. Sproule evaluated and reviewed all of the Company's crude oil, bitumen, natural gas, coal bed methane and NGLs reserves. GLJ evaluated all of the synthetic crude oil reserves related to the Company's oil sands mine. The Company has been granted an exemption from certain provisions of National Instrument 51-101 – "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada. This exemption allows the Company to substitute Securities Exchange Commission ("SEC") requirements under Regulation S-K and S-X for certain disclosures required under NI 51-101. In February 2009 the SEC released its final rules for the *modernization of oil and gas reporting ("Final Rule")*. The material changes include the ability to include oil sands mining as an oil and gas activity, ability to use reliable technology to establish undeveloped reserves, the optional ability to report probable reserves, the requirement to track undeveloped locations, as well as the directive to use twelve month average prices and current costs. These resulting changes are more in line with the NI 51-101 however there are material differences to the type of volumes disclosed and the basis from which the volumes are determined. NI 51-101 requires gross reserves and future net revenue under forecast pricing and costs, however, the SEC, as discussed, requires disclosure of net reserves, after royalties, under twelve month average prices and current costs. Therefore the difference between the reported numbers under the two disclosure standards can be material. The Company discloses its synthetic crude oil, bitumen, crude oil and NGLs and natural gas reserve reconciliations net of royalties in adherence to SEC requirements.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with Sproule and GLJ as to the Company's reserves.

Corporate net reserves

- Proved finding and on-stream costs, excluding Horizon SCO reserves, were $19.81 per barrel of oil equivalent with total reserve additions replacing 69% of production. On a three-year basis, proved finding and on-stream costs were $17.76 per barrel of oil equivalent. Using proved and probable reserves, finding and on-stream costs were $22.64 per barrel of oil equivalent and averaged $17.41 per barrel of oil equivalent over the past three years.
- Economic price revisions on natural gas resulted in a reduction of 327 billion cubic feet, 19 million barrels of crude oil and NGLs and 307 million barrels of SCO proved reserves. Absent these revisions and excluding Horizon SCO, proved finding and on-stream costs would have been reported at $12.28 per barrel of oil equivalent.
- Under revised SEC reporting guidelines, crude oil and natural gas reserves now include Horizon SCO reserves. The net proved SCO reserves, on a stand alone basis, have an associated cumulative Phase 1 finding and on-stream cost of $5.82 per barrel of oil equivalent.

North American net reserves

- Proved finding and on-stream costs for North American operations, excluding the impact of Horizon SCO reserves, were $12.78 per barrel of oil equivalent.
- Net proved reserve additions, excluding economic revisions due to prices, replaced 176% of 2009 production at a finding and on-stream cost of $6.45 per barrel of oil equivalent. Net proved and probable reserve additions, excluding economic revisions due to prices, replaced 213% of 2009 production at a finding and on-stream cost of $5.32 per barrel of oil equivalent.

International

- North Sea net proved reserves were 16 million barrels of oil equivalent less than 2008 as a result of technical revisions which were largely offset by positive price revisions.
- In Offshore West Africa net proved reserves decreased by 21 million barrels of oil equivalent to 137 million barrels of oil equivalent in 2009 due to production and negative price revisions.

RESERVES OF CRUDE OIL AND NATURAL GAS, NET OF ROYALTIES[1][2]

	December 31, 2009			
	Proved Developed	Proved Undeveloped	Proved Total	Proved and Probable
Crude oil and NGLs (mmbbl)				
North America - Synthetic crude oil [3]	1,589	61	1,650	2,512
North America - Bitumen [4]	268	427	695	1,213
North America - Crude oil and NGLs	204	115	319	447
North Sea	94	146	240	387
Offshore West Africa	106	17	123	179
	2,261	**766**	**3,027**	**4,738**
Natural gas (bcf)				
North America	2,333	694	3,027	3,992
North Sea	45	22	67	94
Offshore West Africa	81	4	85	124
	2,459	**720**	**3,179**	**4,210**
Total reserves (mmboe)	**2,671**	**886**	**3,557**	**5,440**

CRUDE OIL AND NGLs RESERVES RECONCILIATION, NET OF ROYALTIES[1]

	North America				International		Total
Net Proved Reserves (mmbbl) [2]	Synthetic Crude Oil [3]	Bitumen [4]	Crude Oil & NGLs	Total	North Sea	Offshore West Africa	
Reserves, December 31, 2008	–	690	258	948	256	142	1,346
Extensions and discoveries	–	24	6	30	–	–	30
Infill drilling	–	8	1	9	–	–	9
Improved recovery	–	–	74	74	–	–	74
SEC Reliable Technology [5]	–	7	–	7	–	–	7
SEC Rule Transition [6]	1,650	–	–	1,650	–	–	1,650
Purchases of reserves in place	–	–	1	1	–	–	1
Sales of reserves in place	–	–	–	–	–	–	–
Production	–	(49)	(24)	(73)	(14)	(11)	(98)
Economic revisions due to prices	–	(64)	(8)	(72)	57	(4)	(19)
Revisions of prior estimates	–	79	11	90	(59)	(4)	27
Reserves, December 31, 2009	**1,650**	**695**	**319**	**2,664**	**240**	**123**	**3,027**

	North America				International		Total
Net Proved and Probable Reserves (mmbbl)[7]	Synthetic Crude Oil [3]	Bitumen [4]	Crude Oil & NGLs	Total	North Sea	Offshore West Africa	
Reserves, December 31, 2008	–	1,238	361	1,599	399	191	2,189
Extensions and discoveries	–	35	11	46	-	-	46
Infill drilling	–	12	2	14	-	-	14
Improved recovery	–	-	110	110	-	-	110
SEC Reliable Technology [5]	–	10	-	10	-	-	10
SEC Rule Transition [6]	2,512	-	-	2,512	-	-	2,512
Purchases of reserves in place	-	-	2	2	-	-	2
Sales of reserves in place	-	-	-	-	-	-	-
Production	-	(49)	(24)	(73)	(14)	(11)	(98)
Economic revisions due to prices	-	(135)	(3)	(138)	13	(6)	(131)
Revisions of prior estimates	-	102	(12)	90	(11)	5	84
Reserves, December 31, 2009	**2,512**	**1,213**	**447**	**4,172**	**387**	**179**	**4,738**

NATURAL GAS RESERVES RECONCILIATION, NET OF ROYALTIES[1]

Net Proved Reserves (bcf) [2]	North America	North Sea	Offshore West Africa	Total
Reserves, December 31, 2008	3,523	67	94	3,684
Extensions and discoveries	92	-	-	92
Infill drilling	7	-	-	7
Improved recovery	4	-	-	4
SEC Reliable Technology [5]	-	-	-	-
Property purchases	15	-	-	15
Property disposals	(6)	-	-	(6)
Production	(443)	(4)	(6)	(453)
Economic revisions due to prices	(335)	12	(4)	(327)
Revisions of prior estimates	170	(8)	1	163
Reserves, December 31, 2009	**3,027**	**67**	**85**	**3,179**
Net Proved and Probable Reserves (bcf)[7]				
Reserves, December 31, 2008	4,619	94	131	4,844
Extensions and discoveries	111	-	-	111
Infill drilling	9	-	-	9
Improved recovery	4	-	-	4
SEC Reliable Technology [5]	-	-	-	-
Property purchases	19	-	-	19
Property disposals	(7)	-	-	(7)
Production	(443)	(4)	(6)	(453)
Economic revisions due to prices	(429)	7	(5)	(427)
Revisions of prior estimates	109	(3)	4	110
Reserves, December 31, 2009	**3,992**	**94**	**124**	**4,210**

FINDING AND ON-STREAM COSTS (excluding Horizon SCO reserves and capital)

	2009	2008	2007	Three Year Total
Net reserve replacement expenditures ($ millions)	**$ 2,377**	$ 3,475	$ 3,027	**$ 8,879**
Net reserve additions (mmboe) [8]				
Proved	**120**	168	212	**500**
Proved and probable	**105**	237	168	**510**
Finding and on-stream costs ($/boe) [9]				
Proved	**$ 19.81**	$ 20.68	$ 14.28	**$ 17.76**
Proved and probable	**$ 22.64**	$ 14.66	$ 18.02	**$ 17.41**

(1) December 31, 2009 reserve estimates are based upon 2009 twelve month average reference price assumptions, as detailed below, and current costs. Twelve month average price, as defined by the SEC, is the unweighted average price of the first day of the month within the twelve month period prior to the end of the reporting period. Prior to December 31, 2009 year end prices and costs were used in the reserves estimates

	2009 12 Month Average Price	2008 Year end Price	2007 Year end Price		**2009 12 Month Average Price**	2008 Year end Price	2007 Year end Price
Crude oil and NGLs				***Natural gas***			
WTI @ Cushing Oklahoma (US$/bbl)	***$ 61.18***	*$ 44.60*	*$ 96.00*	*Henry Hub Louisiana (US$/mmbtu)*	***$ 3.87***	*$ 5.63*	*$ 6.80*
WCS (C$/bbl)	***$ 58.49***	*$ 33.07*	*$ n/a*	*Alberta AECO C (C$/mmbtu)*	***$ 3.87***	*$ 6.34*	*$ 6.52*
North Sea Brent (US$/bbl)	***$ 59.91***	*$ 41.76*	*$ 96.02*	*British Columbia Huntingdon (C$/mmbtu)*	***$ 3.92***	*$ 7.48*	*$ 6.96*
Company Average Price (C$/bbl)	***$ 59.39***	*$ 34.51*	*$ 62.87*	*Company Average Price (C$/mcf)*	***$ 4.02***	*$ 6.51*	*$ 6.96*

A foreign exchange rate of US$0.87/C$1.00 was used in the 2009 evaluation; US$0.82/C$1.00 was used in the 2008 evaluation; US$1.01/C$1.00 was used in the 2007 evaluation.

(2) Proved reserve estimates were evaluated in accordance with the new SEC requirements. The stated reserves have a reasonable certainty of being economically recovered using twelve month average prices and current costs held constant throughout the productive life of the properties.

(3) Prior to January 1, 2010 Horizon Oil Sands SCO reserves were reported separately in accordance to the SEC's Industry Guide 7. With SEC's Final Rule in effect January 1, 2010, this synthetic crude oil is now included in the Company's crude oil and natural gas reserve totals.

(4) Bitumen as defined by the SEC, under the Final Rule, "is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis." Under this definition, all the Company's thermal and primary heavy crude oil reserves have been classified as bitumen. Prior to January 1, 2010, these reserves would have been classified within the Company's conventional crude oil and NGL totals.

(5) SEC Reliable Technology accounts for reserves volumes added due to the reserves rule changes to allow booking of undeveloped reserves beyond 1 spacing unit with supporting geoscience and engineering data.

(6) SEC Rule Transition accounts for the inclusion of synthetic crude oil reserves volume additions as a result of oil sands mining reserves being included as a crude oil and natural gas activity effective January 1, 2010. For continuity purposes, with respect to the transition from Industry Guide 7 into the SEC's Final Rule, the following SCO table has been provided to illustrate the changes in the Horizon Oil Sands SCO reserves for the 2009 year.

Horizon Oil Sands Mining SCO Reserves	***Net Proved (mmbbl)***	***Net Proved and Probable (mmbbl)***
Reserves, December 31, 2008	*1,946*	*2,944*
Production	*(18)*	*(18)*
Economic revisions due to prices	*(307)*	*(434)*
Revisions of prior estimates	*29*	*20*
Reserves, December 31, 2009	***1,650***	***2,512***

(7) The December 31, 2009 probable reserves have been evaluated in accordance to the new SEC requirements. Probable reserves are less certain to be recovered then proved but which when added with proved are as likely as not to be recovered. Prior to December 31, 2009, proved and probable reserve estimates and values were evaluated in accordance with the standards of the COGEH and as mandated by NI 51-101.

(8) Reserves additions are comprised of all categories of reserves changes, exclusive of production and SCO reserves.

(9) Reserves finding and on-stream costs are determined by dividing total cash capital expenditures for each year by net reserves additions for that year. It excludes costs associated with head office, abandonments, midstream and the Horizon Oil Sands.

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, production volumes, royalties, operating costs, capital expenditures 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 Horizon Oil Sands Mining and Upgrading operations, Primrose East, Pelican Lake, Olowi Field (Offshore Gabon), and the Kirby Thermal Oil Sands Project 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 if 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 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 difficulties in mining, extracting or upgrading 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; 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, bitumen, natural gas and liquids 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 should circumstances or Management's estimates or opinions change.

Management's Discussion and Analysis

Management's Discussion and Analysis 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 year ended December 31, 2009 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2008.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The financial statements have been prepared in accordance with generally accepted accounting principles in Canada ("GAAP"). 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 GAAP 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 GAAP, 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 GAAP, 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.

The calculation of barrels of oil equivalent ("boe") is based on a conversion ratio of six thousand cubic feet ("mcf") of natural gas to one barrel ("bbl") of crude oil to estimate relative energy content. This conversion may be misleading, particularly when used in isolation, since the 6 mcf:1 bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the wellhead.

Production volumes and per barrel 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 for the year and three months ended December 31, 2009 in relation to the comparable periods in 2008 and the third quarter of 2009. The accompanying tables form an integral part of this MD&A. This MD&A is dated March 3, 2010. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2008, 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			Year Ended	
	Dec 31 2009	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Revenue, before royalties	**$ 3,319**	$ 2,823	$ 2,511	**$ 11,078**	$ 16,173
Net earnings	**$ 455**	$ 658	$ 1,770	**$ 1,580**	$ 4,985
Per common share – basic and diluted	**$ 0.85**	$ 1.21	$ 3.27	**$ 2.92**	$ 9.22
Adjusted net earnings from operations (1)	**$ 667**	$ 658	$ 697	**$ 2,689**	$ 3,492
Per common share – basic and diluted	**$ 1.23**	$ 1.21	$ 1.29	**$ 4.96**	$ 6.46
Cash flow from operations (2)	**$ 1,703**	$ 1,506	$ 1,570	**$ 6,090**	$ 6,969
Per common share – basic and diluted	**$ 3.14**	$ 2.78	$ 2.90	**$ 11.24**	$ 12.89
Capital expenditures, net of dispositions	**$ 694**	$ 574	$ 1,827	**$ 2,997**	$ 7,451

(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 below 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

($ millions)	*Three Months Ended*			*Year Ended*	
	Dec 31 2009	*Sep 30 2009*	*Dec 31 2008*	***Dec 31 2009***	*Dec 31 2008*
Net earnings as reported	***$ 455***	*$ 658*	*$ 1,770*	***$ 1,580***	*$ 4,985*
Stock-based compensation expense (recovery), net of tax (a)	***65***	*126*	*(145)*	***261***	*(38)*
Unrealized risk management loss (gain), net of tax (b)	***224***	*217*	*(1,435)*	***1,437***	*(2,112)*
Unrealized foreign exchange (gain) loss, net of tax (c)	***(77)***	*(343)*	*507*	***(570)***	*698*
Effect of statutory tax rate and other legislative changes on future income tax liabilities (d)	**–**	–	–	***(19)***	*(41)*
Adjusted net earnings from operations	***$ 667***	*$ 658*	*$ 697*	***$ 2,689***	*$ 3,492*

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

(b) Derivative financial instruments are recorded at fair value on the balance sheet, 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.

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

(d) All substantively enacted or enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's consolidated balance sheet in determining future 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 or enacted. Income tax rate changes in the first quarter of 2009 resulted in a reduction of future income tax liabilities of approximately $19 million in North America. Income tax rate changes in the first quarter of 2008 resulted in a reduction of future income tax liabilities of approximately $19 million in North America and $22 million in Côte d'Ivoire, Offshore West Africa.

Cash Flow from Operations

($ millions)	Three Months Ended Dec 31 2009	Sep 30 2009	Dec 31 2008	Year Ended Dec 31 2009	Dec 31 2008
Net earnings	**$ 455**	$ 658	$ 1,770	**$ 1,580**	$ 4,985
Non-cash items:					
Depletion, depreciation and amortization	**836**	673	666	**2,819**	2,683
Asset retirement obligation accretion	**23**	24	19	**90**	71
Stock-based compensation expense (recovery)	**87**	172	(203)	**355**	(52)
Unrealized risk management loss (gain)	**308**	274	(2,107)	**1,991**	(3,090)
Unrealized foreign exchange (gain) loss	**(88)**	(391)	613	**(661)**	832
Deferred petroleum revenue tax expense (recovery)	**7**	13	(5)	**15**	(67)
Future income tax expense (recovery)	**75**	83	817	**(99)**	1,607
Cash flow from operations	**$ 1,703**	$ 1,506	$ 1,570	**$ 6,090**	$ 6,969

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the year ended December 31, 2009 were $1,580 million compared to $4,985 million for the year ended December 31, 2008. The 2009 operating results of the Company were significantly impacted by lower benchmark crude oil and natural gas pricing, partially offset by the impact of the commencement of production from Horizon. Net earnings for the year ended December 31, 2009 included net unrealized after-tax expenses of $1,109 million related to the effects of risk management activities, fluctuations in foreign exchange rates and stock-based compensation, and the impact of statutory tax rate changes on future income tax liabilities, compared to net unrealized after-tax income of $1,493 million for the year ended December 31, 2008. Excluding these items, adjusted net earnings from operations for the year ended December 31, 2009 were $2,689 million compared to $3,492 million for the year ended December 31, 2008. The decrease in adjusted net earnings from the year ended December 31, 2008 was primarily due to the impact of lower realized pricing, lower natural gas sales volumes, higher production expenses, higher depletion, depreciation, and amortization expense, including the impact of a ceiling test impairment in Gabon, Offshore West Africa, higher accretion expense, higher interest expense, and the impact of realized foreign exchange loss, partially offset by the impact of higher crude oil sales volumes, lower royalty expense, realized risk management activities and the weaker Canadian dollar relative to the US dollar.

Net earnings for the fourth quarter of 2009 were $455 million compared to net earnings of $1,770 million for the fourth quarter of 2008 and $658 million for the prior quarter. Net earnings for the fourth quarter of 2009 included net unrealized after-tax expenses of $212 million related to the effects of risk management activities, and fluctuations in foreign exchange rates and stock-based compensation, compared to net unrealized after-tax income of $1,073 million for the fourth quarter of 2008. The decrease in adjusted net earnings from the fourth quarter of 2008 was primarily due to the impact of lower natural gas sales volumes, higher royalty and production expenses, higher depletion, depreciation, and amortization expense, including the impact of a ceiling test impairment in Gabon, Offshore West Africa, higher interest expense, lower realized risk management gains, the impact of realized foreign exchange loss, and the stronger Canadian dollar relative to the US dollar partially offset by the impact of higher realized pricing, and higher crude oil sales volumes. The increase in adjusted net earnings from the prior quarter was primarily due to the impact of higher crude oil sales volumes related to Horizon and higher realized crude oil pricing offset by the impact of lower natural gas sales volumes, lower realized risk management gains, higher royalty expense, higher depletion, depreciation, and amortization expense, and the impact of realized foreign exchange loss and the stronger Canadian dollar relative to the US dollar.

The impacts of unrealized risk management activities, stock-based compensation, and changes in foreign exchange rates are expected to continue to contribute to significant 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 year ended December 31, 2009 was $6,090 million compared to $6,969 million for the year ended December 31, 2008. Cash flow from operations for the fourth quarter of 2009 was $1,703 million compared to $1,570 million for the fourth quarter of 2008 and $1,506 million for the prior quarter. The decrease in cash flow from operations from the year ended 2008 was primarily due to the impact of lower realized pricing, lower natural gas sales volumes, higher production expense, higher interest expense, and the impact of realized foreign exchange, partially offset by the impact of higher crude oil sales volumes, realized risk management gains, lower royalty expense, lower current income tax and Production Revenue Tax ("PRT") expense, and the impact of the weaker Canadian dollar relative to the US dollar. The increase in cash flow from operations from the fourth quarter of 2008 was primarily due to the impact of higher crude oil sales volumes and higher realized crude oil pricing, partially offset by the impact of lower natural gas sales volumes, lower realized natural gas pricing, lower realized risk management gains, higher royalty and production expense, the impact of realized foreign exchange losses and the stronger Canadian dollar relative to the US dollar. The increase in cash flow from operations from the prior quarter was primarily due to the impact of higher realized pricing, partially offset by the impact of lower natural gas sales volumes, lower realized risk management gains, the impact of realized foreign exchange loss and the stronger Canadian dollar relative to the US dollar.

During 2009, the Company achieved first production of synthetic crude oil ("SCO") at Horizon in connection with the commencement of operations. The Company continues to focus on stabilizing and ramping up production as the plant is fine-tuned with a focus on safety, reliability, and cost control. The results of operations for Horizon are included in the "Oil Sands Mining and Upgrading" segment.

Total production before royalties for the year ended December 31, 2009 increased 2% to 574,730 boe/d from 564,845 boe/d for the year ended December 31, 2008. Total production before royalties for the fourth quarter of 2009 increased 5% to 574,857 boe/d from 547,399 boe/d for the fourth quarter of 2008 and was comparable with the prior quarter. Total production for the fourth quarter of 2009 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)	**Dec 31 2009**	Sep 30 2009	Jun 30 2009	Mar 31 2009
Revenue, before royalties	**$ 3,319**	$ 2,823	$ 2,750	$ 2,186
Net earnings	**$ 455**	$ 658	$ 162	$ 305
Net earnings per common share				
– Basic and diluted	**$ 0.85**	$ 1.21	$ 0.30	$ 0.56

($ millions, except per common share amounts)	Dec 31 2008	Sep 30 2008	Jun 30 2008	Mar 31 2008
Revenue, before royalties	$ 2,511	$ 4,583	$ 5,112	$ 3,967
Net earnings (loss)	$ 1,770	$ 2,835	$ (347)	$ 727
Net earnings (loss) per common share				
– Basic and diluted	$ 3.27	$ 5.25	$ (0.65)	$ 1.35

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

- **Crude oil pricing** – The impact of fluctuating demand and geopolitical uncertainties on worldwide benchmark pricing, and the fluctuations in the Heavy Crude Oil Differential from WTI ("Heavy Differential") in North America.
- **Natural gas pricing** – The impact of seasonal fluctuations in both the demand for natural gas and inventory storage levels, and the impact of increased shale gas production in the US, as well as fluctuations in imports of liquefied natural gas into the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production from the Company's Primrose thermal projects, the results from the Pelican Lake water and polymer flood projects, and the commencement of operations at Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore West Africa and the impact of the shut in, and subsequent restoration, of some of the production in the Baobab Field.

- **Natural gas sales volumes** – Production declines 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.
- **Production expense** – Fluctuations primarily due to the impact of the demand for services, industry-wide inflationary cost pressures experienced in prior quarters, fluctuations in product mix, the impact of seasonal costs that are dependent on weather, and the commencement of operations at Horizon and the Olowi Field in Offshore Gabon.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, the commencement of operations at Horizon and the Olowi Field in Offshore Gabon, and the impact of a ceiling test impairment at the Olowi Field at December 31, 2009.
- **Stock-based compensation** – Fluctuations due to the mark-to-market movements of the Company's stock-based compensation liability. Stock-based compensation expense (recovery) reflected fluctuations in the Company's share price.
- **Risk management** – Fluctuations due to the recognition of realized and unrealized gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Foreign exchange rates** – Fluctuations in the Canadian dollar relative to the US dollar 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. Similarly, unrealized foreign exchange gains and losses were recorded with respect to US dollar denominated debt and the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars, partially offset by the impact of cross currency swap hedges.
- **Income tax expense (recovery)** – Fluctuations in income tax expense (recovery) include statutory tax rate and other legislative changes substantively enacted or enacted in the various periods.

BUSINESS ENVIRONMENT

	Three Months Ended			Year Ended	
(Quarterly and Yearly Average)	**Dec 31 2009**	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
WTI benchmark price (US$/bbl)	**$ 76.17**	$ 68.29	$ 58.75	**$ 61.93**	$ 99.65
Dated Brent benchmark price (US$/bbl)	**$ 74.54**	$ 68.28	$ 54.93	**$ 61.61**	$ 96.99
WCS blend differential from WTI (US$/bbl)	**$ 12.08**	$ 10.06	$ 19.13	**$ 9.64**	$ 20.03
WCS blend differential from WTI (%)	**16%**	15%	33%	**16%**	20%
SCO price (US$/bbl)	**$ 75.07**	$ 67.20	$ 58.64	**$ 61.51**	$ 102.48
Condensate benchmark price (US$/bbl)	**$ 74.46**	$ 65.80	$ 59.01	**$ 60.60**	$ 100.10
NYMEX benchmark price (US$/mmbtu)	**$ 4.27**	$ 3.42	$ 6.82	**$ 4.03**	$ 8.95
AECO benchmark price (C$/GJ)	**$ 4.01**	$ 2.87	$ 6.43	**$ 3.91**	$ 7.71
US / Canadian dollar average exchange rate	**$ 0.9468**	$ 0.9108	$ 0.8252	**$ 0.8760**	$ 0.9381

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$61.93 per bbl for the year ended December 31, 2009, a decrease of 38% from US$99.65 per bbl for the year ended December 31, 2008. WTI averaged US$76.17 per bbl for the fourth quarter of 2009, an increase of 30% from US$58.75 per bbl for the fourth quarter of 2008, and an increase of 12% from US$68.29 per bbl for the prior quarter. WTI pricing was impacted by strong Asian demand, partially offset by declines in the European and North American markets due to weak economic activity.

Crude oil sales contracts for the Company's North Sea and Offshore West Africa segments are typically based on Dated Brent ("Brent") pricing, which is more reflective of international markets and the overall supply and demand balance. Brent averaged US$61.61 per bbl for the year ended December 31, 2009, a decrease of 36% compared to US$96.99 per bbl for the year ended December 31, 2008. Brent averaged US$74.54 per bbl for the fourth quarter of 2009, an increase of 36% compared to US$54.93 per bbl for the fourth quarter of 2008, and an increase of 9% from US$68.28 per bbl for the prior quarter.

The Heavy Differential averaged 16% for the year ended December 31, 2009 compared to 20% for the year ended December 31, 2008. The Heavy Differential averaged 16% for the fourth quarter of 2009, compared to 33% for the fourth quarter of 2008 and 15% for the prior quarter. The narrow Heavy Differential continued to reflect the relatively weak refinery margins.

The Company anticipates continued volatility in crude oil pricing benchmarks due to the unpredictable nature of supply and demand factors, geopolitical events and the timing and extent of recovery of the global economy. The Heavy Differential is expected to continue to reflect seasonal demand fluctuations and refinery margins.

NYMEX natural gas prices averaged US$4.03 per mmbtu for the year ended December 31, 2009, a decrease of 55% from US$8.95 per mmbtu for the year ended December 31, 2008. NYMEX natural gas prices averaged US$4.27 per mmbtu for the fourth quarter of 2009, a decrease of 37% from US$6.82 per mmbtu for the fourth quarter of 2008, and an increase of 25% from US$3.42 per mmbtu for the prior quarter. AECO natural gas prices for the year ended December 31, 2009 decreased 49% to average $3.91 per GJ from $7.71 per GJ for the year ended December 31, 2008. AECO natural gas prices for the fourth quarter of 2009 decreased 38% to average $4.01 per GJ from $6.43 per GJ in the fourth quarter of 2008, and increased 40% from $2.87 per GJ for the prior quarter. Decreases in natural gas prices from the comparable periods in the prior year were primarily related to record storage levels in North America due to an oversupply in the market. Natural gas pricing in the fourth quarter improved due to seasonal demands and production shut ins by producers.

Update to Alberta Royalty Framework

Effective January 1, 2009, changes to the Alberta royalty regime under the Alberta Royalty Framework ("ARF") include the implementation of a sliding scale for oil sands royalties ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout, depending on benchmark crude oil pricing.

In addition, effective January 1, 2009, new royalty formulas under the ARF for conventional crude oil and natural gas operate on sliding scales ranging up to 50%, determined by commodity prices and well productivity.

In March 2009, the Government of Alberta announced new incentive programs to stimulate activity in Alberta. These programs provide for:

- A royalty credit of $200 per meter on new conventional crude oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, to a maximum of 10% of conventional Crown royalties paid in Alberta.
- Reduced royalty rates that set the maximum royalty at 5% for the first 12 months of production, up to a maximum of 50,000 boe or 500 mmcfe, for new conventional crude oil and natural gas wells that commence production between April 1, 2009 and March 31, 2010.

In June 2009, the Government of Alberta extended the two incentive programs described above by one year, to March 31, 2011.

Province of British Columbia Oil and Gas Stimulus Package

Effective September 1, 2009, the Province of British Columbia announced an oil and gas stimulus package that includes:

- A one-year, 2% royalty rate for all natural gas wells drilled between September 1, 2009 and June 30, 2010. Qualifying wells must commence production before December 31, 2010.
- A permanent increase of 15% in the existing royalty holiday credits for the Deep Royalty Program.
- Permanent qualification of horizontal wells drilled to a vertical depth between 1,900 and 2,300 meters into the Deep Royalty Program.
- An additional $50 million allocation for the Infrastructure Royalty Credit Program to stimulate investment in oil and gas roads and pipelines.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2009	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Crude oil and NGLs (bbl/d)					
North America – Conventional	**229,206**	223,307	240,831	**234,523**	243,826
North America – Oil Sands Mining and Upgrading	**70,194**	66,907	–	**50,250**	–
North Sea	**34,408**	34,034	42,991	**37,761**	45,274
Offshore West Africa	**32,643**	35,021	25,748	**32,929**	26,567
	366,451	359,269	309,570	**355,463**	315,667
Natural gas (mmcf/d)					
North America	**1,218**	1,264	1,405	**1,287**	1,472
North Sea	**12**	8	10	**10**	10
Offshore West Africa	**20**	21	12	**18**	13
	1,250	1,293	1,427	**1,315**	1,495
Total barrels of oil equivalent (boe/d)	**574,857**	574,755	547,399	**574,730**	564,845
Product mix					
Light/medium crude oil and NGLs	**20%**	20%	22%	**21%**	22%
Pelican Lake crude oil	**7%**	6%	7%	**6%**	6%
Primary heavy crude oil	**15%**	15%	16%	**15%**	16%
Thermal heavy crude oil	**10%**	9%	12%	**11%**	12%
Synthetic crude oil	**12%**	12%	–	**9%**	–
Natural gas	**36%**	38%	43%	**38%**	44%
Percentage of gross revenue (1) (excluding midstream revenue)					
Crude oil and NGLs	**78%**	79%	60%	**75%**	68%
Natural gas	**22%**	21%	40%	**25%**	32%

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2009	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Crude oil and NGLs (bbl/d)					
North America – Conventional	**195,070**	191,077	210,496	**201,873**	207,933
North America – Oil Sands Mining and Upgrading	**67,806**	64,814	–	**48,833**	–
North Sea	**34,341**	33,961	42,910	**37,683**	45,182
Offshore West Africa	**30,296**	30,551	23,907	**29,922**	22,641
	327,513	320,403	277,313	**318,311**	275,756
Natural gas (mmcf/d)					
North America	**1,135**	1,228	1,198	**1,214**	1,225
North Sea	**12**	8	10	**10**	10
Offshore West Africa	**19**	18	10	**17**	11
	1,166	1,254	1,218	**1,241**	1,246
Total barrels of oil equivalent (boe/d)	**521,894**	529,421	480,409	**525,103**	483,541

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/medium crude oil and NGLs, Pelican Lake crude oil, primary heavy crude oil, thermal heavy crude oil, and SCO.

Total crude oil and NGLs production for the year ended December 31, 2009 increased 13% to 355,463 bbl/d from 315,667 bbl/d for the year ended December 31, 2008. The increase from the comparable period was primarily due to the commencement of production from Horizon and the Olowi Field in Offshore Gabon and the restoration of some of the production in the Baobab Field, in Offshore Côte D'Ivoire.

Total crude oil and NGLs production for the fourth quarter of 2009 increased 18% to 366,451 bbl/d from 309,570 bbl/d for the fourth quarter of 2008, and 2% from 359,269 bbl/d for the prior quarter. The increase from the fourth quarter in 2008 was primarily due to production from Horizon and the Olowi Field in Offshore Gabon. The increase from the prior quarter was in line with expectations and primarily due to the cyclic nature of the Company's thermal production and the timing of planned maintenance activities in the North Sea. Crude oil and NGLs production in the fourth quarter of 2009 was within the Company's previously issued guidance of 359,000 to 390,000 bbl/d.

Natural gas production continued to represent the Company's largest product offering for the year ended December 31, 2009, accounting for 38% of the Company's total production. Natural gas production for the year ended December 31, 2009 decreased 12% to 1,315 mmcf/d compared to 1,495 mmcf/d for the year ended December 31, 2008. Natural gas production for the fourth quarter of 2009 decreased 12% to 1,250 mmcf/d compared to 1,427 mmcf/d for the fourth quarter of 2008 and 3% from 1,293 mmcf/d for the prior quarter. The decrease in natural gas production from the comparable periods reflects the expected production declines due to the Company's strategic reduction in natural gas drilling activity. Natural gas production in the fourth quarter of 2009 exceeded the Company's previously issued guidance of 1,213 to 1,243 mmcf/d.

For 2010, annual production guidance is targeted to average between 400,000 and 445,000 bbl/d of crude oil and NGLs and between 1,117 and 1,185 mmcf/d of natural gas. First quarter 2010 production guidance is targeted to average between 372,000 and 409,000 bbl/d of crude oil and NGLs and between 1,197 and 1,221 mmcf/d of natural gas.

North America – Conventional

North America conventional crude oil and NGLs production for the year ended December 31, 2009 decreased 4% to average 234,523 bbl/d from 243,826 bbl/d for the year ended December 31, 2008. Fourth quarter North America conventional crude oil and NGLs production decreased 5% to average 229,206 bbl/d from 240,831 bbl/d for the fourth quarter of 2008, and increased 3% from 223,307 bbl/d for the prior quarter. The fluctuations in crude oil and NGLs production from the prior periods was primarily due to the cyclic nature of the Company's thermal production and was in line with expectations. Production of conventional crude oil and NGLs was within the Company's previously issued guidance of 225,000 bbl/d to 235,000 bbl/d for the fourth quarter of 2009.

Natural gas production for the year ended December 31, 2009 decreased 13% to 1,287 mmcf/d from 1,472 mmcf/d for the year ended December 31, 2008. For the fourth quarter of 2009, natural gas production decreased 13% to 1,218 mmcf/d from 1,405 mmcf/d for the fourth quarter of 2008, and decreased 4% from 1,264 mmcf/d for the prior quarter. The decreases in natural gas production were consistent with the Company's strategic decision to reduce natural gas drilling activity. Production of natural gas exceeded the Company's previously issued guidance of 1,185 mmcf/d to 1,210 mmcf/d for the fourth quarter of 2009.

North America – Oil Sands Mining and Upgrading

Horizon Phase 1 achieved first production of synthetic crude oil during 2009. Production averaged 50,250 bbl/d for the year ended December 31, 2009 and 70,194 bbl/d in the fourth quarter of 2009, up 5% from 66,907 bbl/d in the prior quarter. Production volumes fluctuated throughout the quarter as the Company continued to stabilize and ramp up production. During December 2009, production was impacted by an equipment failure in the hydrogen plant, requiring the shutdown for an extended period of time, and issues with one of the coker furnaces. As a consequence, fourth quarter production was at the low end of the Company's previously issued guidance of 70,000 bbl/d to 85,000 bbl/d for the fourth quarter of 2009. The Company has been able to resolve the impact of high clay content much sooner than anticipated by blending the ore from three benches.

North Sea

North Sea crude oil production for the year ended December 31, 2009 decreased 17% to 37,761 bbl/d from 45,274 bbl/d for the year ended December 31, 2008. Fourth quarter North Sea crude oil production decreased 20% to 34,408 bbl/d from 42,991 bbl/d for the fourth quarter of 2008 and was comparable to the prior quarter. Production in the fourth quarter of 2009 was at the low end of the Company's previously issued guidance due to delays in restoring certain production after the completion of maintenance activities.

Offshore West Africa

Offshore West Africa crude oil production increased 24% to 32,929 bbl/d for the year ended December 31, 2009 from 26,567 bbl/d for the year ended December 31, 2008. Fourth quarter Offshore West Africa crude oil production increased 27% to 32,643 bbl/d from 25,748 bbl/d for the fourth quarter of 2008, and decreased 7% from 35,021 bbl/d for the prior quarter. Production in the fourth quarter was at the high end of the Company's previously issued guidance as a result of strong production performance from the Baobab Field.

Production volumes from the first platform at the Olowi Field continue to be below expectations and, as a result, the Company recognized a ceiling test impairment of $115 million at December 31, 2009. Drilling results and production data is being reviewed in order to develop appropriate remediation strategies and determine the impact on future production from the Field, the impact on recoverable reserves and the scope of the overall development plan. The Company continues drilling at the next scheduled platform with production targeted for second quarter of 2010.

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 offtake vessels, as follows:

(bbl)	**Dec 31 2009**	Sep 30 2009	Dec 31 2008
North America – Conventional	**1,131,372**	761,351	761,351
North America – Oil Sands Mining and Upgrading (SCO)	**1,224,481**	1,035,573	–
North Sea	**713,112**	1,200,129	558,904
Offshore West Africa[1]	**51,103**	1,127,028	1,113,156
	3,120,068	4,124,081	2,433,411

(1) Prior period inventory volumes include one-time adjustments to sales volumes for MD&A reporting purposes only.

OPERATING HIGHLIGHTS – CONVENTIONAL

	Three Months Ended			Year Ended	
	Dec 31 2009	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Crude oil and NGLs ($/bbl) [1]					
Sales price [2]	**$ 68.00**	$ 62.90	$ 45.81	**$ 57.68**	$ 82.41
Royalties	**7.96**	7.89	4.49	**6.73**	10.48
Production expense	**15.45**	16.71	16.33	**15.92**	16.26
Netback	**$ 44.59**	$ 38.30	$ 24.99	**$ 35.03**	$ 55.67
Natural gas ($/mcf) [1]					
Sales price [2]	**$ 4.75**	$ 3.80	$ 7.03	**$ 4.53**	$ 8.39
Royalties [3]	**0.35**	0.13	1.08	**0.32**	1.46
Production expense	**1.03**	1.05	1.06	**1.08**	1.02
Netback	**$ 3.37**	$ 2.62	$ 4.89	**$ 3.13**	$ 5.91
Barrels of oil equivalent ($/boe) [1]					
Sales price [2]	**$ 51.95**	$ 45.52	$ 43.84	**$ 44.87**	$ 68.62
Royalties	**5.60**	4.85	5.37	**4.72**	9.78
Production expense	**11.72**	12.26	12.05	**11.98**	11.79
Netback	**$ 34.63**	$ 28.41	$ 26.42	**$ 28.17**	$ 47.05

(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.

(3) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

PRODUCT PRICES – CONVENTIONAL

	Three Months Ended			Year Ended	
	Dec 31 2009	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 65.12**	$ 60.07	$ 40.39	**$ 54.70**	$ 77.42
North Sea	**$ 78.89**	$ 75.91	$ 63.07	**$ 68.84**	$ 100.31
Offshore West Africa	**$ 72.88**	$ 70.05	$ 65.80	**$ 65.27**	$ 97.96
Company average	**$ 68.00**	$ 62.90	$ 45.81	**$ 57.68**	$ 82.41
Natural gas ($/mcf) (1) (2)					
North America	**$ 4.75**	$ 3.76	$ 7.00	**$ 4.51**	$ 8.41
North Sea	**$ 4.94**	$ 5.70	$ 5.19	**$ 4.66**	$ 4.09
Offshore West Africa	**$ 5.04**	$ 5.72	$ 12.54	**$ 6.11**	$ 10.03
Company average	**$ 4.75**	$ 3.80	$ 7.03	**$ 4.53**	$ 8.39
Company average ($/boe) (1) (2)	**$ 51.95**	$ 45.52	$ 43.84	**$ 44.87**	$ 68.62

(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 29% to average $54.70 per bbl for the year ended December 31, 2009 from $77.42 per bbl for the year ended December 31, 2008. Realized crude oil prices increased 61% to average $65.12 per bbl for the fourth quarter of 2009 from $40.39 per bbl for the fourth quarter of 2008, and increased 8% from $60.07 per bbl for the prior quarter. The decrease from the year ended 2008 was primarily a result of decreased WTI benchmark pricing, partially offset by the impact of the narrowing of the Heavy Differential and the weaker Canadian dollar relative to the US dollar. The increase from the prior quarter and the fourth quarter of 2008 was primarily the result of increased WTI benchmark pricing, partially offset by the impact of the stronger Canadian dollar relative to the US dollar.

The Company continues to focus on its crude oil marketing strategy, and in the fourth quarter of 2009 contributed approximately 140,000 bbl/d of heavy crude oil blends to the Western Canadian Select stream.

In the first quarter of 2010, Canadian Natural announced, together with North West Upgrading Inc., the submission of a joint proposal to the Alberta Government to construct and operate a bitumen refinery near Redwater, Alberta. This proposal was submitted in response to a request for proposal under the Alberta Royalty Framework's Bitumen Royalty In Kind (BRIK) program.

North America realized natural gas prices decreased 46% to average $4.51 per mcf for the year ended December 31, 2009 from $8.41 per mcf for the year ended December 31, 2008. Realized natural gas prices decreased 32% to average $4.75 per mcf for the fourth quarter of 2009 from $7.00 per mcf for the fourth quarter of 2008, and increased 26% from $3.76 per mcf for the prior quarter. The decrease in natural gas prices from the comparable periods of 2008 was primarily related to lower benchmark prices due to lower demand and high storage levels in 2009. The increase in natural gas prices from the prior quarter was primarily related to seasonality of demand.

Comparisons of the prices received for the Company's North America conventional production by product type were as follows:

(Quarterly Average)		**Dec 31 2009**		Sep 30 2009		Dec 31 2008
Wellhead Price (1) (2)						
Light/medium crude oil and NGLs ($/bbl) (3)	**$**	**67.30**	$	59.24	$	46.58
Pelican Lake crude oil ($/bbl)	**$**	**63.75**	$	61.11	$	40.91
Primary heavy crude oil ($/bbl)	**$**	**65.46**	$	60.42	$	37.85
Thermal heavy crude oil ($/bbl)	**$**	**63.62**	$	59.52	$	38.68
Natural gas ($/mcf)	**$**	**4.75**	$	3.76	$	7.00

(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.

(3) Light/medium crude oil and NGLs wellhead pricing for the third quarter of 2009 reflected the impact of significant price discounts for certain types of NGLs, including propane and butane.

North Sea

North Sea realized crude oil prices decreased 31% to average $68.84 per bbl for the year ended December 31, 2009 from $100.31 per bbl for the year ended December 31, 2008. Realized crude oil prices increased 25% to average $78.89 per bbl for the fourth quarter of 2009 from $63.07 per bbl for the fourth quarter of 2008, and increased 4% from $75.91 per bbl for the prior quarter. The decrease in realized crude oil prices in the North Sea from the year ended 2008 was primarily the result of lower Brent benchmark pricing, partially offset by the impact of the weaker Canadian dollar. The increase from the prior quarter and the fourth quarter 2008 was primarily the result of increased Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar.

Offshore West Africa

Offshore West Africa realized crude oil prices decreased 33% to average $65.27 per bbl for the year ended December 31, 2009 from $97.96 per bbl for the year ended December 31, 2008. Realized crude oil prices increased 11% to average $72.88 per bbl for the fourth quarter of 2009 from $65.80 per bbl for the fourth quarter of 2008, and increased 4% from $70.05 per bbl for the prior quarter. The decrease in realized crude oil prices in Offshore West Africa from the year ended 2008 was primarily the result of lower Brent benchmark pricing, partially offset by the impact of the weaker Canadian dollar. The increase from the prior quarter and the fourth quarter of 2008 was primarily the result of increased Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar. Realized crude oil prices in Offshore West Africa were also impacted by the timing of liftings from each field.

ROYALTIES – CONVENTIONAL

	Three Months Ended			Year Ended	
	Dec 31 2009	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 9.88**	$ 8.80	$ 5.25	**$ 7.93**	$ 11.99
North Sea	**$ 0.15**	$ 0.16	$ 0.12	**$ 0.14**	$ 0.21
Offshore West Africa	**$ 5.24**	$ 8.94	$ 4.71	**$ 5.79**	$ 14.81
Company average	**$ 7.96**	$ 7.89	$ 4.49	**$ 6.73**	$ 10.48
Natural gas ($/mcf) (1)					
North America (2)	**$ 0.35**	$ 0.12	$ 1.09	**$ 0.32**	$ 1.47
Offshore West Africa	**$ 0.27**	$ 0.74	$ 1.26	**$ 0.53**	$ 1.52
Company average	**$ 0.35**	$ 0.13	$ 1.08	**$ 0.32**	$ 1.46
Company average ($/boe) (1)	**$ 5.60**	$ 4.85	$ 5.37	**$ 4.72**	$ 9.78
Percentage of revenue (3)					
Crude oil and NGLs	**12%**	13%	10%	**12%**	13%
Natural gas (2)	**7%**	3%	15%	**7%**	17%
Boe	**11%**	11%	12%	**11%**	14%

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

(2) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

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

North America

North America royalties for the year ended December 31, 2009 compared to 2008 reflect weaker realized commodity prices and the impact of the change in the ARF.

Crude oil and NGLs royalties averaged approximately 15% of revenues for the fourth quarter of 2009, compared to 13% for the fourth quarter in 2008 and were consistent with the prior quarter. Crude oil and NGLs royalties per bbl are anticipated to average 17% to 19% of gross revenue for 2010.

Natural gas royalties averaged approximately 7% of revenues for the fourth quarter of 2009 compared to 16% for the fourth quarter of 2008 and 3% for the prior quarter. The decrease in natural gas royalty rates for the fourth quarter of 2009 compared to the prior year was due to the impact of low natural gas benchmark pricing. Natural gas royalties are anticipated to average 11% to 13% of gross revenue for 2010.

Offshore West Africa

Under the terms of the Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital costs, and the timing of liftings from each field. Royalty rates as a percentage of revenue averaged approximately 7% for the fourth quarter of 2009 and 2008 and 13% for the prior quarter. Offshore West Africa royalty rates are anticipated to average 7% to 9% of gross revenue for 2010.

PRODUCTION EXPENSE – CONVENTIONAL

	Three Months Ended			Year Ended	
	Dec 31 2009	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Crude oil and NGLs ($/bbl) [(1)]					
North America	**$ 13.44**	$ 15.19	$ 14.31	**$ 14.63**	$ 14.96
North Sea	**$ 27.03**	$ 31.30	$ 28.77	**$ 26.98**	$ 26.29
Offshore West Africa	**$ 15.26**	$ 13.35	$ 14.47	**$ 12.83**	$ 10.29
Company average	**$ 15.45**	$ 16.71	$ 16.33	**$ 15.92**	$ 16.26
Natural gas ($/mcf) [(1)]					
North America	**$ 1.01**	$ 1.04	$ 1.04	**$ 1.07**	$ 1.00
North Sea	**$ 3.23**	$ 1.57	$ 1.96	**$ 2.16**	$ 2.51
Offshore West Africa	**$ 0.70**	$ 1.37	$ 2.51	**$ 1.23**	$ 1.61
Company average	**$ 1.03**	$ 1.05	$ 1.06	**$ 1.08**	$ 1.02
Company average ($/boe) [(1)]	**$ 11.72**	$ 12.26	$ 12.05	**$ 11.98**	$ 11.79

(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 year ended December 31, 2009 decreased 2% to $14.63 per bbl from $14.96 per bbl for the year ended December 31, 2008. Production expense for the fourth quarter of 2009 decreased 6% to $13.44 per bbl from $14.31 per bbl for the fourth quarter of 2008 and 12% from $15.19 per bbl for the prior quarter. The decrease in production expense per barrel for the fourth quarter of 2009 was a result of the Company's focus on optimizing service costs, together with lower power prices and cost of natural gas used for fuel. North America crude oil and NGLs production expense is anticipated to average $13.00 to $14.00 per bbl for 2010.

North America natural gas production expense for the year ended December 31, 2009 increased 7% to $1.07 per mcf from $1.00 per mcf for the year ended December 31, 2008. Production expense for the fourth quarter of 2009 decreased 3% to $1.01 per mcf from $1.04 per mcf for the fourth quarter of 2008 and the prior quarter. The increase in production expense per mcf from the prior year was primarily a result of lower production volumes on fixed costs. The decrease in production expense from the comparable quarters was due to the Company's focus on optimizing service costs and lower power prices. North America natural gas production expense is anticipated to average $1.15 to $1.25 per mcf for 2010.

North Sea

North Sea crude oil production expense increased on a per barrel basis from the prior year due to lower production volumes on a relatively fixed operating cost base. North Sea crude oil production expense decreased on a per barrel basis from the prior quarter due to the timing of maintenance activities and liftings of each field. Production expense for the year ended December 31, 2009 was below the Company's previously issued guidance and reflected the Company's ongoing focus on lowering costs. Production expense is anticipated to average $31.00 to $35.00 per bbl for 2010.

Offshore West Africa

Offshore West Africa crude oil production expense increased from the prior year and prior quarters on a per barrel basis due to the timing of liftings of each field and as a result of higher operating costs associated with Gabon. Production expense for the year ended December 31 2009 was in line with the Company's previously issued guidance. Production expense is anticipated to average $14.00 to $17.00 per bbl for 2010.

DEPLETION, DEPRECIATION AND AMORTIZATION – CONVENTIONAL

	Three Months Ended			Year Ended	
	Dec 31 2009	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Expense ($ millions)	**$ 754**	$ 610	$ 674	**$ 2,656**	$ 2,685
$/boe [1]	**$ 15.68**	$ 12.64	$ 13.20	**$ 13.82**	$ 12.97

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

The increase in Conventional Depletion, Depreciation and Amortization expense from the previous periods was primarily due to the impact of a ceiling test impairment related to Gabon, Offshore West Africa.

ASSET RETIREMENT OBLIGATION ACCRETION – CONVENTIONAL

	Three Months Ended			Year Ended	
	Dec 31 2009	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Expense ($ millions)	**$ 17**	$ 17	$ 19	**$ 69**	$ 71
$/boe [1]	**$ 0.36**	$ 0.36	$ 0.38	**$ 0.36**	$ 0.34

(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

FINANCIAL METRICS

	Three Months Ended			Year Ended	
($/bbl) [1]	**Dec 31 2009**	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
SCO sales price [2]	**$ 76.33**	$ 69.11	$ –	**$ 70.83**	$ –
Bitumen value for royalty purposes	**$ 58.90**	$ 56.79	$ –	**$ 56.57**	$ –
Bitumen royalties [3]	**$ 3.06**	$ 2.19	$ –	**$ 2.15**	$ –

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

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

(3) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

The increase in SCO price from the previous quarter was due to the increase in WTI price. There is an active market for SCO and it has been well received by refiners. The marketing strategy continues to remain flexible.

PRODUCTION COSTS

The following tables provide reconciliations of Oil Sands Mining and Upgrading production costs to the Segmented Information disclosed in note 13 to the Company's unaudited interim consolidated financial statements.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2009**	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Cash costs, excluding natural gas costs	**$ 228**	$ 212	$ –	**$ 599**	$ –
Natural gas costs	**31**	30	–	**84**	–
Total cash production costs	**$ 259**	$ 242	$ –	**$ 683**	$ –

	Three Months Ended			Year Ended	
($/bbl) (1)	**Dec 31 2009**	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Cash costs, excluding natural gas costs	**$ 36.23**	$ 32.36	$ –	**$ 34.97**	$ –
Natural gas costs	**4.98**	4.49	–	**4.92**	–
Total cash production costs	**$ 41.21**	$ 36.85	$ –	**$ 39.89**	$ –
Sales (bbl/d)	**68,140**	71,578	–	**46,896**	–

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

First sales from Horizon occurred in the second quarter of 2009.

Total cash production costs averaged $41.21 per bbl in the fourth quarter of 2009 compared to $36.85 per bbl for the third quarter due to higher operating costs associated with winter operations, together with higher maintenance costs relating to an equipment failure in the hydrogen plant requiring the shutdown for an extended period of time in December, and issues with one of the coker furnaces. Oil Sands Mining and Upgrading production expense is anticipated to average $31.00 to $37.00 per bbl for 2010.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2009**	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Depreciation, depletion and amortization	**$ 83**	$ 66	$ –	**$ 187**	$ –
Asset retirement obligation accretion	**6**	7	–	**21**	–
Total	**$ 89**	$ 73	$ –	**$ 208**	$ –

	Three Months Ended			Year Ended	
($/bbl) (1)	**Dec 31 2009**	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Depreciation, depletion and amortization	**$ 13.28**	$ 9.99	$ –	**$ 10.95**	$ –
Asset retirement obligation accretion	**1.00**	0.95	–	**1.22**	–
Total	**$ 14.28**	$ 10.94	$ –	**$ 12.17**	$ –

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

During 2009, Horizon Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs has ceased, and depletion, depreciation and amortization of these assets has commenced. Depletion, depreciation and amortization per barrel increased in the fourth quarter of 2009 compared to the prior quarter due to the disposal of a portion of the tailings line pipe related to premature wear.

MIDSTREAM

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2009**	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Revenue	**$ 18**	$ 18	$ 17	**$ 72**	$ 77
Production expense	**5**	4	6	**19**	25
Midstream cash flow	**13**	14	11	**53**	52
Depreciation	**3**	2	2	**9**	8
Segment earnings before taxes	**$ 10**	$ 12	$ 9	**$ 44**	$ 44

Midstream operating results were consistent with the comparable periods.

ADMINISTRATION EXPENSE

	Three Months Ended			Year Ended	
	Dec 31 2009	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Expense ($ millions)	**$ 49**	$ 38	$ 46	**$ 181**	$ 180
$/boe (1)	**$ 0.92**	$ 0.72	$ 0.91	**$ 0.87**	$ 0.87

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

Administration expense for the fourth quarter of 2009 increased from the prior quarter due to higher staffing related costs. Administration expense on a boe basis in 2009 includes sales volumes associated with the commencement of Horizon.

STOCK-BASED COMPENSATION EXPENSE

($ millions)	Three Months Ended **Dec 31 2009**	Sep 30 2009	Dec 31 2008	Year Ended **Dec 31 2009**	Dec 31 2008
Expense (recovery)	**$ 87**	$ 172	$ (203)	**$ 355**	$ (52)

The Company recorded a $355 million ($261 million after-tax) stock-based compensation expense for the year ended December 31, 2009 primarily as a result of normal course graded vesting of options granted in prior periods, the impact of vested options exercised or surrendered during the period, and the 56% increase in the Company's share price, including an $87 million ($65 million after-tax) stock-based compensation expense for the three months ended December 31, 2009 (Company's share price as at: December 31, 2009 – $76.00; September 30, 2009 – $72.30; December 31, 2008 – $48.75). For the year ended December 31, 2009, the Company capitalized $2 million in stock-based compensation to Oil Sands Mining and Upgrading (December 31, 2008 – $23 million recovery). The stock-based compensation liability reflected the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on December 31, 2009.

For the year ended December 31, 2009, the Company paid $94 million for stock options surrendered for cash settlement (December 31, 2008 – $207 million).

INTEREST EXPENSE

($ millions, except per boe amounts)	Three Months Ended **Dec 31 2009**	Sep 30 2009	Dec 31 2008	Year Ended **Dec 31 2009**	Dec 31 2008
Expense, gross	**$ 119**	$ 124	$ 158	**$ 516**	$ 609
Less: capitalized interest, Oil Sands Mining and Upgrading	**8**	6	135	**106**	481
Expense, net	**$ 111**	$ 118	$ 23	**$ 410**	$ 128
$/boe (1)	**$ 2.06**	$ 2.23	$ 0.45	**$ 1.96**	$ 0.62
Average effective interest rate	**4.5%**	4.3%	5.0%	**4.3%**	5.1%

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

Gross interest expense decreased from the comparable periods in 2008 primarily due to lower variable interest rates and debt repayments, and reflected the impact of fluctuations in foreign exchange rates on US dollar denominated debt. The Company's average effective interest rate decreased from the comparable periods in 2008 primarily due to lower variable interest rates.

During the first quarter of 2009, interest capitalization ceased on Horizon Phase 1 as the Phase 1 assets were completed and available for their intended use, increasing net interest expense accordingly.

RISK MANAGEMENT ACTIVITIES

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

($ millions)	Three Months Ended Dec 31 2009	Three Months Ended Sep 30 2009	Three Months Ended Dec 31 2008	Year Ended Dec 31 2009	Year Ended Dec 31 2008
Crude oil and NGLs financial instruments	**$ (148)**	$ (235)	$ (179)	**$ (1,330)**	$ 2,020
Natural gas financial instruments	**–**	–	–	**(33)**	(21)
Foreign currency contracts and interest rate swaps	**26**	35	(122)	**110**	(139)
Realized (gain) loss	**$ (122)**	$ (200)	$ (301)	**$ (1,253)**	$ 1,860
Crude oil and NGLs financial instruments	**$ 328**	$ 208	$ (2,112)	**$ 2,039**	$ (3,104)
Natural gas financial instruments	**(17)**	(4)	(13)	**(58)**	16
Foreign currency contracts and interest rate swaps	**(3)**	70	18	**10**	(2)
Unrealized loss (gain)	**$ 308**	$ 274	$ (2,107)	**$ 1,991**	$ (3,090)
Net loss (gain)	**$ 186**	$ 74	$ (2,408)	**$ 738**	$ (1,230)

Complete details related to outstanding derivative financial instruments at December 31, 2009 are disclosed in note 11 to the Company's unaudited interim consolidated financial statements.

Due to changes in crude oil and natural gas forward pricing and the reversal of prior period unrealized gains and losses, the Company recorded a net unrealized loss of $1,991 million ($1,437 million after-tax) on its risk management activities for the year ended December 31, 2009, including a $308 million ($224 million after-tax) net unrealized loss for the fourth quarter of 2009 (September 30, 2009 – unrealized loss of $274 million, $217 million after-tax; December 31, 2008 – unrealized gain of $2,107 million, $1,435 million after-tax).

FOREIGN EXCHANGE

($ millions)	Three Months Ended Dec 31 2009	Three Months Ended Sep 30 2009	Three Months Ended Dec 31 2008	Year Ended Dec 31 2009	Year Ended Dec 31 2008
Net realized loss (gain)	**$ 4**	$ (33)	$ (51)	**$ 30**	$ (114)
Net unrealized (gain) loss (1)	**(88)**	(391)	613	**(661)**	832
Net (gain) loss	**$ (84)**	$ (424)	$ 562	**$ (631)**	$ 718

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

The net unrealized foreign exchange gain for the year ended December 31, 2009 was primarily due to the strengthening Canadian dollar with respect to the US dollar debt, offset by the impact of the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling. The net unrealized (gain) loss for the respective periods was also impacted by the cross currency swaps (three months ended December 31, 2009 – unrealized loss of $48 million, September 30, 2009 – unrealized loss of $172 million, December 31, 2008 – unrealized gain of $313 million; year ended December 31, 2009 – unrealized loss of $338 million, December 31, 2008 – unrealized gain of $449 million). The net realized foreign exchange loss for the year ended December 31, 2009 was primarily due to the result of foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The Canadian dollar ended the fourth quarter at US$0.9555 (September 30, 2009 – US$0.9327; December 31, 2008 – US$0.8166).

TAXES

($ millions, except income tax rates)	Three Months Ended **Dec 31 2009**	Sep 30 2009	Dec 31 2008	Year Ended **Dec 31 2009**	Dec 31 2008
Current	**$ 25**	$ 10	$ 27	**$ 91**	$ 245
Deferred	**7**	13	(5)	**15**	(67)
Taxes other than income tax	**$ 32**	$ 23	$ 22	**$ 106**	$ 178
North America (1)	**$ 11**	$ 7	$ –	**$ 28**	$ 33
North Sea	**60**	55	12	**278**	340
Offshore West Africa	**23**	28	12	**82**	128
Current income tax	**94**	90	24	**388**	501
Future income tax expense (recovery)	**75**	83	817	**(99)**	1,607
	169	173	841	**289**	2,108
Income tax rate and other legislative changes (2)	**–**	–	–	**19**	41
	$ 169	$ 173	$ 841	**$ 308**	$ 2,149
Effective income tax rate on adjusted net earnings from operations	**28.4%**	25.7%	23.7%	**24.3%**	27.8%

(1) Includes North America Conventional Crude Oil and Natural Gas, Midstream, and Oil Sands Mining and Upgrading segments.

(2) Includes the effect of a recovery of $19 million due to British Columbia corporate income tax rate reductions substantively enacted or enacted during the first quarter of 2009 and a recovery of $19 million due to British Columbia corporate income tax rate reductions and $22 million due to Côte d'Ivoire corporate income tax rate reductions substantively enacted or enacted during the first quarter of 2008.

Taxes other than income tax primarily includes current and deferred PRT, which is charged on certain fields in the North Sea at the rate of 50% of net operating income, after allowing for certain deductions including related capital and abandonment expenditures.

Taxable income from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in subsequent periods. North America current income taxes have been provided on the basis of this corporate structure. In addition, current income taxes in each business segment will vary depending on available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

The Company is subject to income tax reassessments arising in the normal course. The Company does not believe that any liabilities ultimately arising from these reassessments will be material.

For 2010, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense in Canada of $450 million to $550 million and in the North Sea of $220 million to $260 million.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Dec 31 2009	Sep 30 2009	Dec 31 2008	Year Ended Dec 31 2009	Dec 31 2008
Expenditures on property, plant and equipment					
Net property acquisitions (dispositions)	**$ 11**	$ (30)	$ 34	**$ 6**	$ 336
Land acquisition and retention	**28**	18	18	**77**	86
Seismic evaluations	**13**	21	22	**73**	107
Well drilling, completion and equipping	**291**	261	505	**1,244**	1,664
Production and related facilities	**222**	235	382	**977**	1,282
Total net reserve replacement expenditures	**565**	505	961	**2,377**	3,475
Oil Sands Mining and Upgrading:					
Horizon Phase 1 construction costs	**–**	–	557	**69**	2,732
Horizon Phase 1 commissioning and other costs	**–**	–	115	**202**	364
Horizon Phases 2/3 construction costs	**42**	21	94	**104**	336
Capitalized interest, stock-based compensation and other	**12**	11	78	**98**	480
Sustaining capital	**53**	23	–	**80**	–
Total Oil Sands Mining and Upgrading [2]	**107**	55	844	**553**	3,912
Midstream	**1**	–	3	**6**	9
Abandonments [3]	**17**	12	15	**48**	38
Head office	**4**	2	4	**13**	17
Total net capital expenditures	**$ 694**	$ 574	$ 1,827	**$ 2,997**	$ 7,451
By segment					
North America	**$ 436**	$ 358	$ 486	**$ 1,663**	$ 2,344
North Sea	**48**	38	117	**168**	319
Offshore West Africa	**80**	108	358	**544**	811
Other	**1**	1	–	**2**	1
Oil Sands Mining and Upgrading	**107**	55	844	**553**	3,912
Midstream	**1**	–	3	**6**	9
Abandonments [3]	**17**	12	15	**48**	38
Head office	**4**	2	4	**13**	17
Total	**$ 694**	$ 574	$ 1,827	**$ 2,997**	$ 7,451

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

(2) Net expenditures for the Oil Sands Mining and Upgrading assets also include the impact of intersegment eliminations.

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

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core regions where it can dominate the land base and infrastructure. 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 dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures for the year ended December 31, 2009 were $2,997 million compared to $7,451 million for the year ended December 31, 2008. Net capital expenditures for the fourth quarter of 2009 were $694 million compared to $1,827 million for the fourth quarter of 2008 and $574 million for the prior quarter. The decrease in capital expenditures from the prior year reflects the completion of Horizon Phase 1 construction. The increase in capital expenditures from the prior quarter reflects increased drilling activities in the fourth quarter of 2009. Capital expenditures continue to be impacted by the effects of an overall strategic reduction in the North America natural gas drilling program.

Drilling Activity (number of wells)

	Three Months Ended			Year Ended	
	Dec 31 2009	Sep 30 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Net successful natural gas wells	**28**	17	41	**109**	269
Net successful crude oil wells	**195**	262	182	**644**	682
Dry wells	**17**	10	11	**46**	39
Stratigraphic test / service wells	**80**	6	97	**329**	131
Total	**320**	295	331	**1,128**	1,121
Success rate (excluding stratigraphic test / service wells)	**93%**	97%	95%	**94%**	96%

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 58% of the total capital expenditures for the year ended December 31, 2009 compared to approximately 32% for the year ended December 31, 2008.

During the fourth quarter of 2009, the Company targeted 28 net natural gas wells, including 4 wells in Northeast British Columbia, 11 wells in the Northern Plains region, 12 wells in Northwest Alberta, and 1 well in the Southern Plains region. The Company also targeted 212 net crude oil wells. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 159 heavy crude oil wells, 19 Pelican Lake crude oil wells, 14 thermal crude oil wells, and 2 light crude oil wells were drilled. Another 18 wells targeting light crude oil were drilled outside the Northern Plains region.

The Company continued to access its large crude oil drilling inventory to maximize value in both the short and long term. Due to the Company's focus on drilling crude oil wells in recent years, a low natural gas price, and as a result of royalty changes under the ARF, natural gas drilling activities have been reduced. Deferred natural gas well locations have been retained in the Company's prospect inventory.

As part of the phased expansion of its In-Situ Oil Sands Assets, the Company is continuing to develop its Primrose thermal projects. Overall Primrose thermal production for the fourth quarter of 2009 averaged approximately 57,000 bbl/d, compared to approximately 64,000 bbl/d for the fourth quarter of 2008 and approximately 52,000 bbl/d for the prior quarter. The Primrose East expansion was completed and first steaming commenced in September 2008, with first production achieved in the fourth quarter of 2008. During the first quarter of 2009, operational issues on one of the pads caused steaming to cease on all well pads in the Primrose East project area. During the fourth quarter of 2009, the Company continued diagnostic steaming and is working with regulators to commence full steaming.

The next planned phase of the Company's In-Situ Oil Sands Assets expansion is the Kirby project. Final corporate sanction and project scope is targeted for late 2010. Currently the Company is proceeding with the detailed engineering and design work.

Development of new pads and tertiary recovery conversion projects at Pelican Lake continued as expected throughout the fourth quarter of 2009. Drilling consisted of 19 horizontal wells in the fourth quarter. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 38,000 bbl/d for the fourth quarter of 2009, compared to 37,000 bbl/day for both the prior quarter and the fourth quarter of 2008.

For the first quarter of 2010, the Company's overall planned drilling activity in North America is expected to be comprised of 47 natural gas wells and 253 crude oil wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

With construction completed, Horizon Phase 1 assets are now available for their intended use. Accordingly, capitalization of all associated development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs have ceased, and depletion, depreciation and amortization of these assets has commenced. Phase 2/3 spending was focused on the construction of the third Ore Preparation Plant, the Mine Maintenance Shop and additional tankage.

North Sea

In the fourth quarter of 2009, the Company completed a planned maintenance shutdown at one of the Ninian Platforms on time and on budget.

Offshore West Africa

At the Olowi Field, development activities related to infrastructure tie-ins continued throughout the quarter. Drilling commenced on the second platform with targeted production in the second quarter of 2010.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Dec 31 2009**		Sep 30 2009		Dec 31 2008
Working capital (deficit) (1)	**$**	**(514)**	$	(396)	$	392
Long-term debt (2) (3)	**$**	**9,658**	$	10,557	$	13,016
Share capital	**$**	**2,834**	$	2,827	$	2,768
Retained earnings		**16,696**		16,299		15,344
Accumulated other comprehensive (loss) income		**(104)**		(61)		262
Shareholders' equity	**$**	**19,426**	$	19,065	$	18,374
Debt to book capitalization (3) (4)		**33%**		36%		41%
Debt to market capitalization (3) (5)		**19%**		21%		33%
After tax return on average common shareholders' equity (6)		**8%**		16%		33%
After tax return on average capital employed (3) (7)		**6%**		10%		19%

(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 (December 31, 2009 – $nil; September 30, 2009 – $nil; December 31, 2008 – $420 million).

(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 expense for the twelve month trailing period; as a percentage of average capital employed for the period. Average capital employed is the average shareholders' equity and current and long-term debt for the period, including $12,855 million in average capital employed related to Oil Sands Mining and Upgrading assets (September 30, 2009 – $12,642 million; December 31, 2008 – $10,678 million).

At December 31, 2009, 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 is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's December 31, 2008 annual MD&A**.** The Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon these factors, as well as 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 on-going 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 December 31, 2009, the Company had $2,004 million of available credit under its bank credit facilities. The Company's current debt ratings are BBB (high) with a stable trend by DBRS Limited, Baa2 with a stable outlook by Moody's Investors Service and BBB with a stable outlook by Standard & Poor's.

Further details related to the Company's long-term debt at December 31, 2009 are discussed in note 4 to the Company's unaudited interim consolidated financial statements.

Long-term debt was $9,658 million at December 31, 2009, resulting in a debt to book capitalization ratio of 33% (September 30, 2009 – 36%; December 31, 2008 – 41%). This ratio is below the 35% to 45% range targeted by management. The Company remains committed to maintaining a strong balance sheet and flexible capital structure. The Company has hedged a portion of its crude oil and natural gas production for 2010 at prices that protect investment returns to ensure ongoing balance sheet strength and the completion of its capital expenditure programs.

During the fourth quarter of 2009, the Company filed new base shelf prospectuses that allow for the issue of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

The Company's commodity hedging program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs. This program 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 program, the purchase of put options is in addition to the above parameters. As at December 31, 2009, in accordance with the policy, approximately 39% of budgeted crude oil volumes and approximately 17% of budgeted natural gas volumes were hedged using collars for 2010.

Further details related to the Company's commodity related derivative financial instruments outstanding at December 31, 2009 are discussed in note 11 to the Company's unaudited interim consolidated financial statements.

Share capital

As at December 31, 2009, there were 542,327,000 common shares outstanding and 32,106,000 stock options outstanding. As at March 2, 2010, the Company had 542,655,000 common shares outstanding and 30,702,000 stock options outstanding.

On March 3, 2010, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.60 per common share for 2010. The increase represented a 43% increase from 2009, recognizes the stability of the Company's cash flow, and provides a return to Shareholders. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

On March 3, 2010 the Board of Directors approved a resolution to file with the Toronto Stock Exchange a Notice of Intention to purchase by way of normal course issuer bid up to 2.5% of its issued and outstanding common shares. Subject to acceptance by the Toronto Stock Exchange of the Notice of Intention, the purchases would be made through the facilities of the Toronto Stock Exchange and the New York Stock Exchange.

Share split

On March 3, 2010, the Company's Board of Directors approved a resolution to subdivide the Company's common shares on a two for one basis, subject to shareholder approval. The proposal will be voted on at the Company's Annual and Special Meeting of Shareholders to be held on May 6, 2010.

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 December 31, 2009, no entities were consolidated under the Canadian Institute of Chartered Accountants Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at December 31, 2009:

($ millions)	2010	2011	2012	2013	2014	Thereafter
Product transportation and pipeline	$ 207	$ 162	$ 136	$ 125	$ 126	$ 1,051
Offshore equipment operating leases	$ 155	$ 124	$ 103	$ 102	$ 101	$ 261
Offshore drilling	$ 49	$ –	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 16	$ 20	$ 21	$ 31	$ 39	$ 6,479
Long-term debt (2)	$ 400	$ 419	$ 366	$ 819	$ 366	$ 5,424
Interest expense (3)	$ 473	$ 451	$ 415	$ 370	$ 350	$ 4,779
Office leases	$ 25	$ 19	$ 3	$ 2	$ 2	$ –
Other	$ 271	$ 67	$ 23	$ 15	$ 12	$ 34

(1) Amounts represent management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2010 – 2014 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(2) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,897 million of revolving bank credit facilities due to the extendable nature of the facilities.

(3) Interest expense amounts represent the scheduled fixed rate and variable rate cash 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 December 31, 2009.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

The Company is defendant and plaintiff in a number of legal actions. 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.

CRITICAL ACCOUNTING ESTIMATES AND CHANGE IN ACCOUNTING POLICIES

The preparation of financial statements requires the Company to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. Actual results could differ from those estimates. 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, 2008.

For the impact of new accounting standards, refer to note 2 of the unaudited interim consolidated financial statements as at December 31, 2009.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, the CICA's Accounting Standards Board confirmed that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board ("IASB") in place of Canadian GAAP effective January 1, 2011.

The Company has established a formal IFRS project governance structure. The structure includes a Steering Committee, which consists of senior levels of management from finance and accounting, operations and information technology ("IT"). The Steering Committee provides regular updates to the Company's Management and the Audit Committee of the Board of Directors.

The Company's IFRS conversion project has been broken down into the following phases:

- Phase 1 Diagnostic – identification of potential accounting and reporting differences between Canadian GAAP and IFRS.
- Phase 2 Planning – establishment of project governance, processes, resources, budget and timeline.
- Phase 3 Policy Delivery and Documentation – establishment of accounting policies under IFRS.
- Phase 4 Policy Implementation – establishment of processes for accounting and reporting, IT change requirements, and education.
- Phase 5 Sustainment –ongoing compliance with IFRS after implementation.

The Company has completed the Diagnostic and Planning phases (Phases 1 and 2). Significant differences were identified in accounting for Property, Plant & Equipment ("PP&E"), including exploration costs, depletion and depreciation, capitalized interest, impairment testing, and asset retirement obligations. Other significant differences were noted in accounting for stock-based compensation, risk management activities, and income taxes. The Company is continuing to perform the necessary research to develop and document IFRS policies to address the major differences noted (Phase 3). A summary of the significant differences identified is included below. At this time, the impact on the Company's future financial position and results of operations is not reasonably determinable. In addition, certain IFRS standards are expected to change prior to adoption in 2011, and the impact of these potential changes is not known.

The Company has identified, developed and tested process and system changes required to capture data required for IFRS accounting and reporting (Phase 4), including 2010 requirements to capture both Canadian GAAP and IFRS data. IT system changes are substantially complete and implemented as at December 31, 2009.

Summary of Identified IFRS Accounting Policy Differences

Property, Plant & Equipment

Adoption of IFRS will significantly impact the Company's accounting policies for PP&E. For Canadian GAAP purposes, the Company follows the full cost method of accounting for its conventional crude oil and natural gas properties and equipment as prescribed by Accounting Guideline 16 ("AcG16). Application of the full cost method of accounting is discussed in the "Critical Accounting Estimates" section of the 2008 annual MD&A. Significant differences in accounting for PP&E under IFRS include:

- Pre-exploration costs must be expensed. Under full cost accounting, these costs are currently included in the country cost centre.
- Exploration and evaluation costs will be initially capitalized as exploration and evaluation assets. Once technical feasibility and commercial viability of reserves is established for an area, the costs will be transferred to PP&E. If technically feasible and commercially viable reserves are not established for a new area, the costs must be expensed. Under full cost accounting, exploration and evaluation costs are currently disclosed as PP&E but withheld from depletion. Costs are transferred to the depletable assets when proved reserves are assigned or when it is determined that the costs are impaired.
- PP&E for producing properties will be depreciated at an asset level. Under full cost accounting, PP&E is depleted on a country cost centre basis.
- Interest directly attributable to the acquisition or construction of a qualifying asset must be capitalized to the cost of the asset. Under Canadian GAAP, capitalization of interest is discretionary.
- Impairment of PP&E will be tested at a cash generating unit level (the lowest level at which cash inflows can be identified). Under full cost accounting, impairment is tested at the country cost centre level.

IFRS 1 "First-time Adoption of International Financial Reporting Standards" issued by the IASB includes a transition exemption for oil and gas companies following full cost accounting under their previous GAAP. The transition exemption allows full cost companies to allocate their existing full cost PP&E balances using reserve values or volumes to IFRS compliant units of account without requiring retroactive adjustment, subject to an initial impairment test. The Company intends to adopt this transition exemption.

Asset Retirement Obligations

Canadian GAAP accounting requirements for asset retirement obligations ("ARO") are discussed in the "Critical Accounting Estimates" section of the 2008 annual MD&A. A significant difference in accounting for ARO under IFRS is that the liability must be re-measured at each balance sheet date using the current discount rates, whereas under Canadian GAAP the discount rates do not change once the liability is recorded. On transition to IFRS, the change in ARO liability on PP&E for which the full cost exemption above is applied must be recorded in retained earnings. For the change in ARO liability on other non-full cost PP&E, the change will be adjusted to PP&E in accordance with the general exemption for decommissioning liabilities included in IFRS 1. In future periods, the impact of changes in discount rates on the ARO liability for all PP&E is adjusted to PP&E.

Stock-based Compensation

Under Canadian GAAP, the Company's stock option plan liability is valued using the intrinsic value method, calculated as the amount by which the market price of the Company's shares exceeds the exercise price of the option for vested options. Under IFRS, the stock option plan liability must be measured using a fair value option pricing model such as the Black-Scholes model. The Company intends to utilize the exemption in IFRS 1 under which options that were settled prior to January 1, 2010 will not have to be retrospectively restated.

Income Taxes

Both Canadian GAAP and IFRS follow the liability method of accounting for income taxes, where tax liabilities and assets are recognized on temporary differences. However, there are certain exceptions to the treatment of temporary differences under IFRS that may result in an adjustment to the Company's future tax liability under IFRS. In addition, the Company's future tax liability will be impacted by the tax effects of any changes noted in the above areas.

Other IFRS 1 Exemptions

The Company also intends to adopt the following IFRS 1 transition exemptions:

- The Company intends to elect to reset the foreign currency translation adjustment to zero by transferring the Canadian GAAP balance to retained earnings on January 1, 2010, rather than retrospectively restating the balance.
- The Company intends to adopt the IFRS 1 election to not restate business combinations entered into prior to January 1, 2010.

SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flow from operations and net earnings from changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2009, excluding mark-to-market gains (losses) on risk management activities, and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

	Cash flow from operations ($ millions)	Cash flow from operations (per common share, basic)	Net earnings ($ millions)	Net earnings (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl [1]				
Excluding financial derivatives	$ 109	$ 0.20	$ 90	$ 0.17
Including financial derivatives	$ 91	$ 0.17	$ 76	$ 0.14
Natural gas – AECO C$0.10/mcf [1]				
Excluding financial derivatives	$ 33	$ 0.06	$ 24	$ 0.04
Including financial derivatives	$ 18	$ 0.03	$ 14	$ 0.03
Volume changes				
Crude oil – 10,000 bbl/d	$ 161	$ 0.30	$ 105	$ 0.19
Natural gas – 10 mmcf/d	$ 12	$ 0.02	$ 4	$ 0.01
Foreign currency rate change				
$0.01 change in US$ [1]				
Including financial derivatives	$ 95 – 97	$ 0.17 – 0.18	$ 31 – 32	$ 0.06
Interest rate change – 1%	$ 13	$ 0.02	$ 13	$ 0.02

(1) For details of outstanding financial instruments in place, refer to note 11 of the Company's unaudited interim consolidated financial statements.

FINANCIAL STATEMENTS

Consolidated Balance Sheets

(millions of Canadian dollars, unaudited)	**Dec 31 2009**	Dec 31 2008
ASSETS		
Current assets		
Cash and cash equivalents	**$ 13**	$ 27
Accounts receivable	**1,148**	1,059
Inventory, prepaids and other	**584**	455
Future income tax	**146**	–
Current portion of other long-term assets (note 3)	**–**	1,851
	1,891	3,392
Property, plant and equipment (note 13)	**39,115**	38,966
Other long-term assets (note 3)	**18**	292
	$ 41,024	$ 42,650
LIABILITIES		
Current liabilities		
Accounts payable	**$ 240**	$ 383
Accrued liabilities	**1,522**	1,802
Future income tax	**–**	585
Current portion of long-term debt (note 4)	**–**	420
Current portion of other long-term liabilities (note 5)	**643**	230
	2,405	3,420
Long-term debt (note 4)	**9,658**	12,596
Other long-term liabilities (note 5)	**1,848**	1,124
Future income tax	**7,687**	7,136
	21,598	24,276
SHAREHOLDERS' EQUITY		
Share capital (note 7)	**2,834**	2,768
Retained earnings	**16,696**	15,344
Accumulated other comprehensive (loss) income (note 8)	**(104)**	262
	19,426	18,374
	$ 41,024	$ 42,650

Commitments (note 12)

Consolidated Statements of Earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended Dec 31 2009	Three Months Ended Dec 31 2008	Year Ended Dec 31 2009	Year Ended Dec 31 2008
Revenue	**$ 3,319**	$ 2,511	**$ 11,078**	$ 16,173
Less: royalties	**(285)**	(268)	**(936)**	(2,017)
Revenue, net of royalties	**3,034**	2,243	**10,142**	14,156
Expenses				
Production	**819**	615	**2,987**	2,451
Transportation and blending	**351**	290	**1,218**	1,936
Depletion, depreciation and amortization	**836**	666	**2,819**	2,683
Asset retirement obligation accretion (note 5)	**23**	19	**90**	71
Administration	**49**	46	**181**	180
Stock-based compensation expense (recovery) (note 5)	**87**	(203)	**355**	(52)
Interest, net	**111**	23	**410**	128
Risk management activities (note 11)	**186**	(2,408)	**738**	(1,230)
Foreign exchange (gain) loss	**(84)**	562	**(631)**	718
	2,378	(390)	**8,167**	6,885
Earnings before taxes	**656**	2,633	**1,975**	7,271
Taxes other than income tax	**32**	22	**106**	178
Current income tax expense (note 6)	**94**	24	**388**	501
Future income tax expense (recovery) (note 6)	**75**	817	**(99)**	1,607
Net earnings	**$ 455**	$ 1,770	**$ 1,580**	$ 4,985
Net earnings per common share (note 10)				
Basic and diluted	**$ 0.85**	$ 3.27	**$ 2.92**	$ 9.22

Consolidated Statements of Shareholders' Equity

(millions of Canadian dollars, unaudited)	Year Ended **Dec 31 2009**	 Dec 31 2008
Share capital (note 7)		
Balance – beginning of year	**$ 2,768**	$ 2,674
Issued upon exercise of stock options	**24**	18
Previously recognized liability on stock options exercised for common shares	**42**	76
Balance – end of year	**2,834**	2,768
Retained earnings		
Balance – beginning of year	**15,344**	10,575
Net earnings	**1,580**	4,985
Dividends on common shares (note 7)	**(228)**	(216)
Balance – end of year	**16,696**	15,344
Accumulated other comprehensive (loss) income (note 8)		
Balance – beginning of year	**262**	72
Other comprehensive (loss) income, net of taxes	**(366)**	190
Balance – end of year	**(104)**	262
Shareholders' equity	**$ 19,426**	$ 18,374

Consolidated Statements of Comprehensive Income

	Three Months Ended		Year Ended	
(millions of Canadian dollars, unaudited)	**Dec 31 2009**	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Net earnings	**$ 455**	$ 1,770	**$ 1,580**	$ 4,985
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized (loss) income during the period, net of taxes of $1 million (2008 – $1 million) – three months ended; $5 million (2008 – $1 million) – year ended	**(9)**	6	**(33)**	30
Reclassification to net earnings, net of taxes of $nil (2008 – $nil) – three months ended; $1 million (2008 – $6 million) – year ended	**–**	(1)	**(10)**	(12)
	(9)	5	**(43)**	18
Foreign currency translation adjustment				
Translation of net investment	**(34)**	141	**(323)**	172
Other comprehensive (loss) income, net of taxes	**(43)**	146	**(366)**	190
Comprehensive income	**$ 412**	$ 1,916	**$ 1,214**	$ 5,175

Consolidated Statements of Cash Flows

(millions of Canadian dollars, unaudited)	Three Months Ended Dec 31 2009	Three Months Ended Dec 31 2008	Year Ended Dec 31 2009	Year Ended Dec 31 2008
Operating activities				
Net earnings	**$ 455**	$ 1,770	**$ 1,580**	$ 4,985
Non-cash items				
Depletion, depreciation and amortization	**836**	666	**2,819**	2,683
Asset retirement obligation accretion	**23**	19	**90**	71
Stock-based compensation expense (recovery)	**87**	(203)	**355**	(52)
Unrealized risk management loss (gain)	**308**	(2,107)	**1,991**	(3,090)
Unrealized foreign exchange (gain) loss	**(88)**	613	**(661)**	832
Deferred petroleum revenue tax expense (recovery)	**7**	(5)	**15**	(67)
Future income tax expense (recovery)	**75**	817	**(99)**	1,607
Other	**3**	2	**5**	25
Abandonment expenditures	**(17)**	(15)	**(48)**	(38)
Net change in non-cash working capital	**(180)**	(205)	**(235)**	(189)
	1,509	1,352	**5,812**	6,767
Financing activities				
(Repayment) issue of bank credit facilities, net	**(717)**	286	**(2,021)**	(623)
Repayment of senior unsecured notes	**–**	–	**(34)**	(31)
Issue of US dollar debt securities	**–**	–	**–**	1,215
Issue of common shares on exercise of stock options	**3**	1	**24**	18
Dividends on common shares	**(57)**	(54)	**(225)**	(208)
Net change in non-cash working capital	**36**	48	**(12)**	46
	(735)	281	**(2,268)**	417
Investing activities				
Expenditures on property, plant and equipment	**(680)**	(1,817)	**(2,985)**	(7,433)
Net proceeds on sale of property, plant and equipment	**3**	5	**36**	20
Net expenditures on property, plant and equipment	**(677)**	(1,812)	**(2,949)**	(7,413)
Net change in non-cash working capital	**(98)**	192	**(609)**	235
	(775)	(1,620)	**(3,558)**	(7,178)
(Decrease) increase in cash and cash equivalents	**(1)**	13	**(14)**	6
Cash and cash equivalents – beginning of period	**14**	14	**27**	21
Cash and cash equivalents – end of period	**$ 13**	$ 27	**$ 13**	$ 27
Interest paid	**$ 83**	$ 112	**516**	574
Taxes paid				
Taxes other than income tax	**$ 18**	$ 83	**$ 52**	$ 300
Current income tax	**$ 88**	$ 135	**$ 216**	$ 258

Notes to the consolidated financial statements
(tabular amounts in millions of Canadian dollars, unless otherwise stated, unaudited)

1. ACCOUNTING POLICIES

The interim consolidated financial statements of Canadian Natural Resources Limited (the "Company") include the Company and all of its subsidiaries and partnerships, and have been prepared following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2008, except as described in note 2. The 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 financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2008.

During 2009, Horizon Oil Sands ("Horizon") Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs ceased, and depletion, depreciation and amortization of these assets commenced. In addition, the Company recognized additional asset retirement obligations related to its oil sands mining operations and tailings ponds (note 5). All Horizon related financial results are included in the "Oil Sands Mining and Upgrading" segment.

Comparative Figures

Certain prior period figures have been reclassified to conform to the presentation adopted in 2009.

2. CHANGES IN ACCOUNTING POLICIES

During 2009, the Company adopted the following new accounting standards issued by the Canadian Institute of Chartered Accountants ("CICA"):

- **Goodwill and Intangible Assets** – Effective January 1, 2009 Section 3064 – "Goodwill and Intangible Assets" replaced Section 3062 – "Goodwill and Other Intangible Assets" and Section 3450 – "Research and Development Costs". In addition, EIC-27 – "Revenue and Expenditures during the Pre-Operating Period" was withdrawn. The new standard addresses when an internally generated intangible asset meets the definition of an asset. The adoption of this standard, which was adopted retroactively without restatement, did not have an impact on the Company's financial statements.

- **Credit Risk and the Fair Value of Financial Assets and Liabilities** – On January 20, 2009 the Emerging Issues Committee ("EIC") issued a new abstract EIC-173 "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". This abstract concludes that an entity's own credit risk and the credit risk of the counterparty should be taken into account when determining the fair value of financial assets and financial liabilities, including derivative instruments. This abstract applies to all financial assets and liabilities measured at fair value in interim and annual financial statements for periods ending on or after January 20, 2009. The adoption of this abstract did not have a material impact on the Company's results of operations or financial position.

- **Financial Instruments – Disclosures** – Effective October 1, 2009 Section 3862 – "Financial Instruments – Disclosures" was amended to include additional disclosure requirements for fair value measurements of financial instruments and to enhance liquidity risk disclosure requirements. The amendment requires the classification and disclosure of fair value using a three-level hierarchy that reflects the significance of the inputs used in making the fair value measurements. The fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair values of assets and liabilities in Level 2 are based on inputs other than Level 1 quoted prices that are observable for the asset or liability either directly (as prices) or indirectly (derived from prices). The fair values of Level 3 assets and liabilities are not based on observable market data. This amendment affected disclosure only and did not impact the Company's accounting for financial instruments (note 11).

International Financial Reporting Standards

In February 2008, the CICA's Accounting Standards Board confirmed that Canadian publicly accountable entities will be required to adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board in place of generally accepted accounting principles in Canada ("GAAP") effective January 1, 2011. The Company has assessed which accounting policies will be affected by the change to IFRS and continues to assess the potential impact of these changes on its financial position and results of operations.

Recently issued accounting standards under Canadian GAAP

The following standards will be effective for the Company's year beginning on January 1, 2011:

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

Section 1582 – "Business Combinations", 1601 – "Consolidated Financial Statements", and 1602 – "Non-Controlling Interests" replace Section 1581 – "Business Combinations", and 1600 – "Consolidated Financial Statements". Section 1582 is effective for business combinations for acquisition dates on or after January 1, 2011. Earlier adoption is permitted, provided all three new standards are adopted simultaneously. The new standards are the Canadian equivalent of IFRS 3 "Business Combinations" and IAS 27 "Consolidated and Separate Financial Statements". Section 1582 requires equity instruments issued as part of the purchase consideration to be measured at fair value at the acquisition date, rather than the date when the acquisition was agreed to and announced. In addition, most acquisition costs are expensed as incurred, instead of being included in the purchase consideration. The new standard also requires non-controlling interests to be measured at fair value instead of carrying amounts. Section 1602 provides guidance on the treatment of non-controlling interests after acquisition. Section 1601 carries forward existing guidance on the preparation of consolidated financial statements, other than non-controlling interests. There is no impact on the Company's results of operations or financial position at this time.

3. OTHER LONG–TERM ASSETS

	Dec 31 2009	Dec 31 2008
Risk management (note 11)	**$ –**	$ 2,119
Other	**18**	24
	18	2,143
Less: current portion	–	1,851
	$ 18	$ 292

4. LONG–TERM DEBT

	Dec 31 2009	Dec 31 2008
Canadian dollar denominated debt		
Bank credit facilities (bankers' acceptances)	**$ 1,897**	$ 4,073
Medium-term notes	**1,200**	1,200
	3,097	5,273
US dollar denominated debt		
Senior unsecured notes (2009 – US$nil; 2008 – US$31 million)	**–**	38
US dollar debt securities (2009 and 2008 – US$6,300 million)	**6,594**	7,715
Less: original issue discount on senior unsecured notes and US dollar debt securities (1)	**(22)**	(23)
	6,572	7,730
Fair value of interest rate swaps on US dollar debt securities (2)	**38**	68
	6,610	7,798
Long-term debt before transaction costs	**9,707**	13,071
Less: transaction costs (1) (3)	**(49)**	(55)
	9,658	13,016
Less: current portion	**–**	420
	$ 9,658	$ 12,596

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

(2) The carrying values 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 $38 million (2008 – $68 million) to reflect the fair value impact of hedge accounting.

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

Bank credit facilities

As at December 31, 2009, the Company had in place unsecured bank credit facilities of $3,955 million, comprised of:

- a $200 million demand credit facility;
- a revolving syndicated credit facility of $2,230 million maturing June 2012;
- a revolving syndicated credit facility of $1,500 million maturing June 2012; and
- a £15 million demand credit facility related to the Company's North Sea operations.

The revolving syndicated credit facilities are 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 can be made by way of Canadian dollar and US dollar bankers' acceptances, and LIBOR, US base rate and Canadian prime loans.

During 2009, the Company repaid the $2,350 million remaining on the non-revolving syndicated credit facility related to the acquisition of Anadarko Canada Corporation and cancelled the facility.

During the second quarter of 2009, the Company renegotiated its demand credit facility, increasing it to $200 million.

The Company's weighted average interest rate on bank credit facilities outstanding as at December 31, 2009 was 0.8% (December 31, 2008 – 2.2%), and on long-term debt outstanding as at December 31, 2009 was 4.5% (December 31, 2008 – 4.6%)

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $358 million, including $300 million related to Horizon, were outstanding at December 31, 2009.

Medium-term notes

In October 2009, the Company filed a new base shelf prospectus that allows for the issue of up to $3,000 million of medium-term notes in Canada until November 2011. If issued, these securities will bear interest as determined at the date of issuance. The previous base shelf prospectus expired in October 2009.

Senior unsecured notes

During the second quarter of 2009, US$31 million of senior unsecured notes were repaid.

US dollar debt securities

In October 2009, the Company filed a new base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States until November 2011. If issued, these securities will bear interest as determined at the date of issuance. The previous base shelf prospectus expired in October 2009.

5. OTHER LONG–TERM LIABILITIES

	Dec 31 2009	Dec 31 2008
Asset retirement obligations	**$ 1,610**	$ 1,064
Stock-based compensation	**392**	171
Risk management (note 11)	**309**	–
Other	**180**	119
	2,491	1,354
Less: current portion	**643**	230
	$ 1,848	$ 1,124

Asset retirement obligations

At December 31, 2009, the Company's total estimated undiscounted costs to settle its asset retirement obligations were approximately $6,606 million (December 31, 2008 – $4,474 million). These costs will be incurred over the lives of the operating assets and have been discounted using a weighted average credit-adjusted risk-free rate of 6.9% (December 31, 2008 – 6.7%). A reconciliation of the discounted asset retirement obligations is as follows:

	Year Ended Dec 31, 2009	Year Ended Dec 31, 2008
Balance – beginning of year	**$ 1,064**	$ 1,074
Liabilities incurred [1]	**299**	18
Liabilities acquired	**–**	3
Liabilities settled	**(48)**	(38)
Asset retirement obligation accretion	**90**	71
Revision of estimates	**276**	(156)
Foreign exchange	**(71)**	92
Balance – end of year	**$ 1,610**	$ 1,064

(1) During 2009, the Company recognized additional asset retirement obligations related to Horizon and Gabon, Offshore West Africa.

Stock-based compensation

The Company recognizes a liability for the potential cash settlements under its Stock Option Plan. The current portion represents the maximum amount of the liability payable within the next twelve-month period if all vested options are surrendered for cash settlement.

	Year Ended Dec 31, 2009	Year Ended Dec 31, 2008
Balance – beginning of year	**$ 171**	$ 529
Stock-based compensation expense (recovery)	**355**	(52)
Cash payments for options surrendered	**(94)**	(207)
Transferred to common shares	**(42)**	(76)
Capitalized (recovery) to Oil Sands Mining and Upgrading	**2**	(23)
Balance – end of year	**392**	171
Less: current portion	**365**	159
	$ 27	$ 12

6. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Year Ended	
	Dec 31 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Current income tax – North America [1]	**$ 11**	$ –	**$ 28**	$ 33
Current income tax – North Sea	**60**	12	**278**	340
Current income tax – Offshore West Africa	**23**	12	**82**	128
Current income tax expense	**94**	24	**388**	501
Future income tax expense (recovery)	**75**	817	**(99)**	1,607
Income tax expense	**$ 169**	$ 841	**$ 289**	$ 2,108

(1) Includes North America Conventional Crude Oil and Natural Gas, Midstream, and Oil Sands Mining and Upgrading segments.

Taxable income from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in subsequent periods. North America current income taxes have been provided on the basis of this corporate structure. In addition, current income taxes in each business segment will vary depending upon available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

During the first quarter of 2009, substantively enacted income tax rate changes resulted in a reduction of future income tax liabilities of $19 million in British Columbia (2008 – $19 million reduction in British Columbia, $22 million reduction in Côte d'Ivoire).

The Company is subject to income tax reassessments arising in the normal course. The Company does not believe that any liabilities ultimately arising from these reassessments will be material.

7. SHARE CAPITAL

	Year Ended Dec 31, 2009	
Issued **Common shares**	**Number of shares** (thousands)	**Amount**
Balance – beginning of year	**540,991**	**$ 2,768**
Issued upon exercise of stock options	**1,336**	**24**
Previously recognized liability on stock options exercised	**–**	**42**
Balance – end of year	**542,327**	**$ 2,834**

Dividend policy

On March 3, 2010, the Board of Directors set the regular quarterly dividend at $0.15 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.

In March 2009, the Board of Directors set the regular quarterly dividend at $0.105 per common share (2008 – $0.10 per common share).

Normal Course Issuer Bid

On March 3, 2010 the Board of Directors approved a resolution to file with the Toronto Stock Exchange a Notice of Intention to purchase by way of normal course issuer bid up to 2.5% of its issued and outstanding common shares. Subject to acceptance by the Toronto Stock Exchange of the Notice of Intention, the purchases would be made through the facilities of the Toronto Stock Exchange and the New York Stock Exchange.

Share split

On March 3, 2010, the Company's Board of Directors approved a resolution to subdivide the Company's common shares on a two for one basis, subject to shareholder approval. The proposal will be voted on at the Company's Annual and Special Meeting of Shareholders to be held on May 6, 2010.

Stock options

	Year Ended Dec 31, 2009	
	Stock options (thousands)	**Weighted average exercise price**
Outstanding – beginning of year	**30,962**	**$ 51.94**
Granted	**6,736**	**$ 67.91**
Surrendered for cash settlement	**(2,833)**	**$ 27.31**
Exercised for common shares	**(1,336)**	**$ 17.99**
Forfeited	**(1,423)**	**$ 59.55**
Outstanding – end of year	**32,106**	**$ 58.54**
Exercisable – end of year	**10,969**	**$ 53.90**

8. ACCUMULATED OTHER COMPREHENSIVE (LOSS) INCOME

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

	Dec 31 2009	Dec 31 2008
Derivative financial instruments designated as cash flow hedges	**$ 76**	$ 119
Foreign currency translation adjustment	**(180)**	143
	$ (104)	$ 262

9. 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 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 non-GAAP 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 aims over time to maintain its debt to book capitalization ratio in the range of 35% to 45%. However, the Company may exceed the high end of such target range if it is investing in capital projects, undertaking acquisitions, or in periods of lower commodity prices. The Company may be below the low end of the target range when cash flow from operating activities is greater than current investment activities. The ratio is currently below the target range at 33%.

Readers are cautioned that the debt to book capitalization ratio is not defined by GAAP and this financial measure may not be comparable to similar measures presented by other companies. Further, there can be 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 at some point in the future.

	Dec 31 2009	Dec 31 2008
Long-term debt (1)	**$ 9,658**	$ 13,016
Total shareholders' equity	**$ 19,426**	$ 18,374
Debt to book capitalization	**33%**	41%

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

10. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Year Ended	
	Dec 31 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Weighted average common shares outstanding (thousands) – basic and diluted	**542,300**	540,914	**541,925**	540,647
Net earnings – basic and diluted	**$ 455**	$ 1,770	**$ 1,580**	$ 4,985
Net earnings per common share – basic and diluted	**$ 0.85**	$ 3.27	**$ 2.92**	$ 9.22

11. FINANCIAL INSTRUMENTS

The carrying values of the Company's financial instruments by category are as follows:

	Dec 31, 2009		
Asset (liability)	**Loans and receivables at amortized cost**	**Held for trading at fair value**	**Other financial liabilities at amortized cost**
Cash and cash equivalents	**$ –**	**$ 13**	**$ –**
Accounts receivable	**1,148**	**–**	**–**
Other long-term assets	**–**	**–**	**–**
Accounts payable	**–**	**–**	**(240)**
Accrued liabilities	**–**	**–**	**(1,522)**
Other long-term liabilities	**–**	**(309)**	**(167)**
Long-term debt	**–**	**–**	**(9,658)**
	$ 1,148	**$ (296)**	**$ (11,587)**

	Dec 31, 2008		
Asset (liability)	Loans and receivables at amortized cost	Held for trading at fair value	Other financial liabilities at amortized cost
Cash and cash equivalents	$ –	$ 27	$ –
Accounts receivable	1,059	–	–
Other long-term assets	–	2,119	–
Accounts payable	–	–	(383)
Accrued liabilities	–	–	(1,802)
Other long-term liabilities	–	–	(105)
Long-term debt (1)	–	–	(13,016)
	$ 1,059	$ 2,146	$ (15,306)

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

The carrying value 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 financial assets and liabilities are outlined below:

	Dec 31, 2009		
	Carrying value	**Fair value**	
Asset (liability) [1]		**Level 1**	**Level 2**
Other long-term assets	**$ –**	**$ –**	**$ –**
Other long-term liabilities	**(309)**	**–**	**(309)**
Fixed-rate long-term debt[2][3]	**(7,761)**	**(8,212)**	**–**
	$ (8,070)	**$ (8,212)**	**$ (309)**

	Dec 31, 2008		
	Carrying value	Fair value	
Asset (liability) [1]		Level 1	Level 2
Other long-term assets	$ 2,119	$ –	$ 2,119
Other long-term liabilities	–	–	–
Fixed-rate long-term debt[2][3]	(8,943)	(7,649)	–
	$ (6,824)	$ (7,649)	$ 2,119

(1) Excludes financial assets and liabilities where book value 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 values 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 $38 million (2008 – $68 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.

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

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

	Year Ended Dec 31, 2009	Year Ended Dec 31, 2008
Asset (liability)	**Risk management mark-to-market**	Risk management mark-to-market
Balance – beginning of year	**$ 2,119**	$ (1,474)
Net cost of outstanding put options	**–**	297
Net change in fair value of outstanding derivative financial instruments attributable to:		
– Risk management activities	**(1,991)**	3,090
– Interest expense	**(25)**	60
– Foreign exchange	**(338)**	449
– Other comprehensive income	**(78)**	18
– Settlement of interest rate swaps and other	**4**	(20)
	(309)	2,420
Put premium financing obligations [1]	**–**	(301)
Balance – end of year	**(309)**	2,119
Less: current portion	**(182)**	1,851
	$ (127)	$ 268

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

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

	Three Months Ended		Year Ended	
	Dec 31 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Net realized risk management (gain) loss	**$ (122)**	$ (301)	**$ (1,253)**	$ 1,860
Net unrealized risk management loss (gain)	**308**	(2,107)	**1,991**	(3,090)
	$ 186	$ (2,408)	**$ 738**	$ (1,230)

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 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. At December 31, 2009, the Company had the following net derivative financial instruments outstanding to manage its commodity price exposures:

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Crude oil price collars	Jan 2010	–	Mar 2010	6,000 bbl/d	US$60.00	–	US$105.15	WTI
	Jan 2010	–	Jun 2010	100,000 bbl/d	US$60.00	–	US$90.13	WTI
	Jan 2010	–	Sep 2010	50,000 bbl/d	US$65.00	–	US$105.49	WTI
	Jan 2010	–	Dec 2010	50,000 bbl/d	US$60.00	–	US$75.08	WTI
	Jul 2010	–	Dec 2010	50,000 bbl/d	US$65.00	–	US$108.94	WTI

	Remaining term			Volume	Weighted average price			Index
Natural gas								
Natural gas price collars(1)	Jan 2010	–	Dec 2010	220,000 GJ/d	C$6.00	–	C$8.00	AECO

(1) Subsequent to December 31, 2009, the Company entered into 400,000 GJ/d of C$4.50 – C$6.30 natural gas AECO collars for the period April to September 2010.

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.

There were no commodity derivative financial instruments designated as hedges at December 31, 2009.

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 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 December 31, 2009, the Company had the following interest rate swap contracts outstanding:

	Remaining term	Amount ($ millions)	Fixed rate	Floating rate
Interest rate				
Swaps – fixed to floating	Jan 2010 – Dec 2014	US$350	4.90%	LIBOR (1) + 0.38%
Swaps – floating to fixed	Jan 2010 – Feb 2011	C$300	1.0680%	3 month CDOR (2)
	Jan 2010 – Feb 2012	C$200	1.4475%	3 month CDOR (2)

(1) London Interbank Offered Rate

(2) Canadian Dealer Offered Rate

All fixed to floating interest rate related derivative financial instruments designated as hedges at December 31, 2009 were classified as fair value hedges.

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 self-sustaining 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 December 31, 2009, the Company had the following cross currency swap contracts outstanding:

	Remaining term	Amount ($ millions)	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency					
Swaps	Jan 2010 – Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2010 – May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2010 – Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments designated as hedges at December 31, 2009 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2009, the Company had US$1,062 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less.

Financial instrument sensitivities

The following table summarizes the annualized sensitivities of the Company's net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at December 31, 2009 resulting from changes in the specified variable, with all other variables held constant. These sensitivities are prepared on a different basis than those sensitivities disclosed in the Company's other continuous disclosure documents, are limited to the impact of changes in a specified variable applied to financial instruments only and do not represent the impact of a change in the variable on the operating results of the Company taken as a whole. Further, these sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities. In addition, changes in fair value generally can not be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

	Impact on net earnings	Impact on other comprehensive income
Commodity price risk		
Increase WTI US$1.00/bbl	$ (21)	$ –
Decrease WTI US$1.00/bbl	$ 20	$ –
Increase AECO C$0.10/mcf	$ (4)	$ –
Decrease AECO C$0.10/mcf	$ 4	$ –
Interest rate risk		
Increase interest rate 1%	$ (12)	$ 14
Decrease interest rate 1%	$ 8	$ (18)
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$ (29)	$ –
Decrease exchange rate by US$0.01	$ 29	$ –

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 December 31, 2009, 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 non-performance 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 December 31, 2009, the Company had net risk management assets of $7 million with specific counterparties related to derivative financial instruments (December 31, 2008 – $2,119 million).

c) Liquidity risk

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

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

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	$	240	$	–	$	–	$	–
Accrued liabilities	$	1,522	$	–	$	–	$	–
Risk management	$	182	$	15	$	48	$	64
Other long-term liabilities	$	96	$	18	$	32	$	21
Long-term debt (1)	$	400	$	419	$	1,551	$	5,424

(1) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,897 million of revolving bank credit facilities due to the extendable nature of the facilities.

12. COMMITMENTS

As at December 31, 2009, the Company had committed to certain payments as follows:

		2010		2011		2012		2013		2014		Thereafter
Product transportation and pipeline	$	207	$	162	$	136	$	125	$	126	$	1,051
Offshore equipment operating leases	$	155	$	124	$	103	$	102	$	101	$	261
Offshore drilling	$	49	$	–	$	–	$	–	$	–	$	–
Asset retirement obligations (1)	$	16	$	20	$	21	$	31	$	39	$	6,479
Office leases	$	25	$	19	$	3	$	2	$	2	$	–
Other	$	271	$	67	$	23	$	15	$	12	$	34

(1) Amounts represent management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2010 – 2014 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

13. SEGMENTED INFORMATION

	Conventional Crude Oil and Natural Gas															
	North America				North Sea				Offshore West Africa				Total Conventional			
(millions of Canadian dollars, unaudited)	Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008
Segmented revenue	**2,220**	2,116	**7,973**	13,496	**295**	262	**961**	1,769	**307**	186	**913**	944	**2,822**	2,564	**9,847**	16,209
Less: royalties	**(244)**	(259)	**(825)**	(1,876)	**(1)**	(1)	**(2)**	(4)	**(22)**	(14)	**(81)**	(143)	**(267)**	(274)	**(908)**	(2,023)
Segmented revenue, net of royalties	**1,976**	1,857	**7,148**	11,620	**294**	261	**959**	1,765	**285**	172	**832**	801	**2,555**	2,290	**8,939**	14,186
Segmented expenses																
Production	**391**	457	**1,748**	1,881	**103**	117	**376**	457	**63**	41	**179**	102	**557**	615	**2,303**	2,440
Transportation and blending	**346**	301	**1,213**	1,975	**2**	2	**8**	10	**–**	–	**1**	1	**348**	303	**1,222**	1,986
Depletion, depreciation and amortization	**487**	552	**2,060**	2,236	**65**	84	**261**	317	**202**	38	**335**	132	**754**	674	**2,656**	2,685
Asset retirement obligation accretion	**11**	10	**41**	42	**5**	8	**24**	27	**1**	1	**4**	2	**17**	19	**69**	71
Realized risk management activities	**(78)**	(301)	**(880)**	1,861	**(44)**	–	**(373)**	(1)	**–**	–	**–**	–	**(122)**	(301)	**(1,253)**	1,860
Total segmented expenses	**1,157**	1,019	**4,182**	7,995	**131**	211	**296**	810	**266**	80	**519**	237	**1,554**	1,310	**4,997**	9,042
Segmented earnings before the following	**819**	838	**2,966**	3,625	**163**	50	**663**	955	**19**	92	**313**	564	**1,001**	980	**3,942**	5,144
Non-segmented expenses																
Administration																
Stock-based compensation expense (recovery)																
Interest, net																
Unrealized risk management activities																
Foreign exchange (gain) loss																
Total non-segmented expenses																
Earnings before taxes																
Taxes other than income tax																
Current income tax expense																
Future income tax expense (recovery)																
Net earnings																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream				Inter-segment elimination and other				Total			
	Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008
Segmented revenue	**492**	–	**1,253**	–	**18**	17	**72**	77	**(13)**	(70)	**(94)**	(113)	**3,319**	2,511	**11,078**	16,173
Less: royalties	**(18)**	–	**(36)**	–	–	–	–	–	–	6	**8**	6	**(285)**	(268)	**(936)**	(2,017)
Segmented revenue, net of royalties	**474**	–	**1,217**	–	**18**	17	**72**	77	**(13)**	(64)	**(86)**	(107)	**3,034**	2,243	**10,142**	14,156
Segmented expenses																
Production	**259**	–	**683**	–	**5**	6	**19**	25	**(2)**	(6)	**(18)**	(14)	**819**	615	**2,987**	2,451
Transportation and blending	**14**	–	**41**	–	–	–	–	–	**(11)**	(13)	**(45)**	(50)	**351**	290	**1,218**	1,936
Depletion, depreciation and amortization	**83**	–	**187**	–	**3**	2	**9**	8	**(4)**	(10)	**(33)**	(10)	**836**	666	**2,819**	2,683
Asset retirement obligation accretion	**6**	–	**21**	–	–	–	–	–	–	–	–	–	**23**	19	**90**	71
Realized risk management activities	–	–	–	–	–	–	–	–	–	–	–	–	**(122)**	(301)	**(1,253)**	1,860
Total segmented expenses	**362**	–	**932**	–	**8**	8	**28**	33	**(17)**	(29)	**(96)**	(74)	**1,907**	1,289	**5,861**	9,001
Segmented earnings before the following	**112**	–	**285**	–	**10**	9	**44**	44	**4**	(35)	**10**	(33)	**1,127**	954	**4,281**	5,155
Non-segmented expenses																
Administration													**49**	46	**181**	180
Stock-based compensation expense (recovery)													**87**	(203)	**355**	(52)
Interest, net													**111**	23	**410**	128
Unrealized risk management activities													**308**	(2,107)	**1,991**	(3,090)
Foreign exchange (gain) loss													**(84)**	562	**(631)**	718
Total non-segmented expenses													**471**	(1,679)	**2,306**	(2,116)
Earnings before taxes													**656**	2,633	**1,975**	7,271
Taxes other than income tax													**32**	22	**106**	178
Current income tax expense													**94**	24	**388**	501
Future income tax expense (recovery)													**75**	817	**(99)**	1,607
Net earnings													**455**	1,770	**1,580**	4,985

Net additions to property, plant and equipment

	Year Ended					
	Dec 31, 2009			Dec 31, 2008		
	Net Expenditures	**Non Cash/Fair Value Changes (1)**	**Capitalized Costs**	Net Expenditures	Non Cash/Fair Value Changes (1)	Capitalized Costs
North America	**$ 1,663**	**$ 65**	**$ 1,728**	$ 2,344	$ (7)	$ 2,337
North Sea	**168**	**146**	**314**	319	(127)	192
Offshore West Africa	**544**	**111**	**655**	811	6	817
Other	**2**	**–**	**2**	1	–	1
Oil Sands Mining and Upgrading (2)	**553**	**355**	**908**	3,912	10	3,922
Midstream	**6**	**–**	**6**	9	–	9
Head office	**13**	**–**	**13**	17	–	17
	$ 2,949	**$ 677**	**$ 3,626**	$ 7,413	$ (118)	$ 7,295

(1) Asset retirement obligations, future income tax adjustments related to differences between carrying value and tax value, and other fair value adjustments.

(2) Net expenditures for Oil Sands Mining and Upgrading assets also include capitalized interest, stock-based compensation, and the impact of inter-segment eliminations.

	Property, plant and equipment		Total assets	
	Dec 31 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
Segmented assets				
North America	**$ 21,834**	$ 22,151	**$ 22,994**	$ 24,875
North Sea	**1,812**	2,048	**1,968**	2,638
Offshore West Africa(1)	**1,883**	1,894	**2,033**	2,013
Other	**28**	26	**42**	64
Oil Sands Mining and Upgrading	**13,295**	12,573	**13,621**	12,677
Midstream	**203**	206	**306**	315
Head office	**60**	68	**60**	68
	$ 39,115	$ 38,966	**$ 41,024**	$ 42,650

(1) Offshore West Africa property, plant and equipment has been reduced by $115 million to reflect the impact of a ceiling test impairment charge as at December 31, 2009.

Capitalized interest

The Company capitalizes construction period interest to Oil Sands Mining and Upgrading based on costs incurred and the Company's cost of borrowing. Interest capitalization on a particular development phase ceases once construction is substantially complete. For the year ended December 31, 2009, pre-tax interest of $106 million was capitalized to Oil Sands Mining and Upgrading (December 31, 2008 – $481 million).

14. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

Under Canadian full cost accounting guidelines, costs capitalized in each country cost centre are limited to an amount equal to the future net revenues from proved and probable reserves using estimated future prices and costs discounted at the risk-free rate, plus the carrying amount of unproved properties and major development projects (the "ceiling test"). A ceiling test impairment of $115 million was recognized in the Gabon, Offshore West Africa country cost centre under Canadian GAAP at December 31, 2009, as capitalized costs exceeded future net revenues. No other ceiling test impairments were recognized.

Under generally accepted accounting principles in the United States ("US GAAP"), the Company is required to perform a ceiling test calculation as at December 31, 2009, in accordance with the full cost accounting method as set forth by the US Securities and Exchange Commission. This ceiling test calculation limits the costs capitalized in each country cost centre to an amount equal to the future net revenues from proved reserves using the average first-day-of-the-month price during the previous twelve-month period and costs as at the balance sheet date, discounted at 10%, plus the carrying amount of unproved properties and major development projects, net of tax. Had the Company prepared its financial statements in accordance with US GAAP, these differences in applying the ceiling test would have resulted in the recognition of additional ceiling test impairments in the Canada and Gabon, Offshore West Africa country cost centres, reducing property, plant and equipment by a further $993 million ($815 million net of tax) in 2009.

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 2009. 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 December 31, 2009:

Interest coverage (times)	
Net earnings [1]	4.4 x
Cash flow from operations [2]	13.3 x

(1) Net earnings plus income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

(2) Cash flow from operations plus current income taxes and interest expense; 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, March 4, 2010. The North American conference call number is 1-800-769-8320 and the outside North American conference call number is 001-416-695-6616. Please call in about 10 minutes before the starting time in order to be patched into the call. The conference call will also be broadcast live on the internet and may be accessed through the Canadian Natural website at www.cnrl.com.

A taped rebroadcast will be available until 6:00 p.m. Mountain Time, Thursday, March 11, 2010. To access the postview in North America, dial 1-800-408-3053. Those outside of North America, dial 001-416-695-5800. The passcode to use is 1207316.

WEBCAST

This call is being webcast and can be accessed on Canadian Natural's website at www.cnrl.com/investor_info/calendar.html.

2010 FIRST QUARTER RESULTS

The 2010 first quarter results are scheduled for release on Thursday, May 6, 2010. A conference call is scheduled to be held on Friday, May 7, 2010 at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time.

For further information, please contact:

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