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NEWS RELEASE

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES FIRST OIL AT HORIZON OIL SANDS PROJECT AND 2008 FOURTH QUARTER AND YEAR END RESULTS

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Commenting on fourth quarter and 2008 annual results, Canadian Natural's Chairman, Allan Markin stated, "Canadian Natural's defined plan has delivered strong quarterly and annual results. The first half of the year saw a strong market for crude oil accompanied by record pricing. This buoyant business environment was then offset by the economic challenges faced in the second half of 2008, and which are expected to continue well into 2009. We strive to create value for our shareholders, and work towards capturing opportunity regardless of the business cycle. Our teams continue to develop cost effective alternatives in developing our portfolio of projects and to deliver our defined growth plan. On that note, I am pleased to report that we achieved first synthetic crude oil production at the Horizon Oil Sands Project on February 28, 2009, a major milestone for Canadian Natural, adding tremendous value for shareholders. We would like to thank those people working on Horizon for their tireless effort over the last 4 years from Project sanction in February 2005."

John Langille, Vice-Chairman, commented, "We had a unique and challenging year in 2008 in terms of managing through the worldwide economic downturn and associated commodity price cycle swing. Strong crude oil prices for a large portion of 2008, combined with operating and capital discipline, helped us achieve cash flow of nearly $7 billion for the year. We also reached the mid-point of our targeted debt levels. Despite a much less robust price environment in 2009, a very strong hedge program combined with Canadian Natural's disciplined management will ensure free cash flow for debt repayment during the year. Canadian Natural's long term financial strategies - which includes flexible capital allocation and budgeting - along with strength in our balance sheet allows us to make the most of our opportunities, even in this challenging economic environment."

Canadian Natural's President and Chief Operating Officer, Steve Laut, continued, "As a result of the current pricing environment Canadian Natural has deferred $800 million of its 2009 capital program. The deferral is a proactive action taken as a result of weak commodity prices particularly on the natural gas side of the business. At the current commodity prices and cost environment, the economics for all but the very best projects are marginal. Although we have not seen anything appreciable to date, as we move through this cycle we fully expect we will achieve better returns through acquisitions rather than developing our portfolio of assets. In addition, we expect to see improved productivity and unit cost improvements on the operational and developmental sides of the business. Therefore we are taking the prudent step to reduce our capital program now, to ensure balance sheet strength and position ourselves for opportunities later in 2009 and in 2010.

Focusing on year-end conventional reserves for 2008, Canadian Natural replaced 95% of 2008 production through the drill bit with finding and on-stream costs of $20.68 per barrel of oil equivalent for proved reserves and $14.66 per barrel of oil equivalent for proved and probable reserves. The year over year increase in finding and on-stream costs are a reflection of the reduced year-end pricing and its associated impact on year end reserves, particularly in the North Sea. In North America, finding and on-stream costs of $13.08 per barrel of oil equivalent for proved reserves were achieved.

Although our production history at Horizon has been very short, at this point all operating units appear to be performing at design capacity. In the immediate near term, we will focus on stabilizing performance and filling the product tanks in preparation for blending and introducing first synthetic crude oil into the Horizon pipeline for shipment to Edmonton and ultimate sale. For the remainder of 2009, our focus at Horizon will be on ramping up production volumes, increasing reliability and reducing operating costs."

HIGHLIGHTS

($ millions, except as noted)	Quarterly Results Q4/08	Q3/08	Q4/07	Year End Results 2008	2007
Net earnings	**$ 1,770**	$ 2,835	$ 798	**$ 4,985**	$ 2,608
per common share, basic and diluted	**$ 3.27**	$ 5.25	$ 1.48	**$ 9.22**	$ 4.84
Adjusted net earnings from operations (1)	**$ 697**	$ 963	$ 546	**$ 3,492**	$ 2,406
per common share, basic and diluted	**$ 1.29**	$ 1.78	$ 1.02	**$ 6.46**	$ 4.46
Cash flow from operations (2)	**$ 1,570**	$ 1,815	$ 1,486	**$ 6,969**	$ 6,198
per common share, basic and diluted	**$ 2.90**	$ 3.36	$ 2.75	**$ 12.89**	$ 11.49
Capital expenditures, net of dispositions	**$ 1,827**	$ 1,744	$ 1,514	**$ 7,451**	$ 6,425
Daily production, before royalties					
Natural gas (mmcf/d)	**1,427**	1,490	1,589	**1,495**	1,668
Crude oil and NGLs (bbl/d)	**309,570**	306,970	337,240	**315,667**	331,232
Equivalent production (boe/d)	**547,399**	555,356	601,908	**564,845**	609,206

(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 repay debt. The derivation of this measure is discussed in the MD&A.

Annual

- The Company's natural gas assets delivered as expected, averaging 1,495 mmcf/d for 2008, a decrease of 10% from 2007. As anticipated, 2008 entry to exit natural gas production volumes declined due to reduced capital re-investment and an associated 30% reduction in natural gas net drilling activity.

- Total crude oil and NGLs production in 2008 averaged 315,667 bbl/d, a 5% decrease from 2007. Crude oil volumes were lower due to decreased North Sea production volumes, the timing of the steam cycle at Primrose, and capturing incremental thermal reserves in the first half of the year, taking advantage of the high crude oil price environment at the time.

- Cash flow from operations increased 12% to nearly $7.0 billion in 2008 from $6.2 billion in 2007, and net earnings increased 91% in 2008 to $5.0 billion from $2.6 billion in 2007. The increase in cash flow was primarily due to increased product pricing net of realized risk management activities.

Fourth Quarter

- Total crude oil and NGLs production for Q4/08 was 309,570 bbl/d. Q4/08 crude oil production volumes increased 1% from Q3/08 of 306,970 bbl/d, and decreased 8% from Q4/07 of 337,240 bbl/d. Volumes in Q4/08 reflect the transition between steam and production cycles for Primrose thermal wells, the beginning of production from the Primrose East expansion, and continued conversion of production wells to polymer injection wells at Pelican Lake, along with scheduled turnarounds in the North Sea and Offshore West Africa.

- Natural gas production volumes for the fourth quarter represented 43% of the Company's total production. Natural gas production for Q4/08 averaged 1,427 mmcf/d, down 4% from 1,490 mmcf/d for Q3/08 and down 10% from 1,589 mmcf/d for Q4/07. The decrease in volumes for Q4/08 from Q4/07 reflected the reallocation of capital towards higher return crude oil projects.

- Quarterly cash flow from operations was just under $1.6 billion, a 13% decrease from Q3/08 and an increase of 6% from Q4/07. The decrease from Q3/08 primarily reflected lower crude oil and natural gas price realizations partially offset by higher realized risk management activity for the quarter. The increase from Q4/07 reflects the impact of lower royalty expense, higher realized natural gas pricing, and higher realized risk management activity. These factors were partially offset by the impact of lower sales volumes and lower realized crude oil pricing.

- Quarterly net earnings for Q4/08 of $1.8 billion 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 Q4/08 were $697 million, an increase of 28% from Q4/07.

- Completed the Q4/08 North America drilling program targeting 190 net crude oil wells and 43 net natural gas wells with a 95% 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.

Operational and Financial

- Maintained a strong undeveloped conventional core land base in Canada of 11.5 million net acres - a key asset for continued value growth.

- Improvements at the Pelican Lake Field continue with the conversion of water flood wells to polymer flood wells, with production averaging approximately 37,000 bbl/d.

- The Primrose East expansion, which added 40,000 bbl/d of capacity, achieved first production in late October 2008.

- The drilling program at Baobab in Offshore Côte d'Ivoire has progressed with three wells completed in Q4/08 and restoring production of approximately 7,500 bbl/d net to Canadian Natural. Drilling continues on the fourth and final well and is targeted to be complete in Q2/09.

- At the Olowi Project in Offshore Gabon, first crude oil is expected in late Q1/09 or early Q2/09. During Q4/08, installation of the Conductor Supported Platform Deck and construction of the Floating, Production, Storage and Offtake Vessel ("FPSO") were completed. The FPSO arrived on location in February 2009. Two appraisal wells and two production wells have been drilled and development activity is continuing.

- First synthetic crude oil production was achieved at the Horizon Oil Sands Project ("Horizon Project") on February 28, 2009.

- An independent qualified reserves evaluator evaluated 100% of the Company's conventional crude oil and natural gas reserves under constant prices and costs as at December 31, 2008:

    - Total net proved reserves from conventional operations at the end of 2008 amounted to 1.35 billion barrels of crude oil and NGLs and 3.68 trillion cubic feet of natural gas. Total net proved conventional reserves decreased slightly from 2007.

    - Solely due to economic revisions as a direct result of lower commodity prices, there was a reduction of net proved reserves of approximately 56.5 million barrels of proved oil equivalent, with a 90.3 million barrel reduction from the North Sea, offset by positive economic revisions of 24.8 million barrels from North America and 9.0 million barrels from Offshore West Africa.

    - Net proved reserve additions from conventional operations equaled 95% of 2008 net production, at a finding and on-stream cost of $20.68 per barrel of oil equivalent. The Company's three-year average proved finding and on-stream costs were $16.55 per barrel of oil equivalent.

    - North America crude oil and NGLs proved reserves increased by 3% replacing 137% of production while natural gas proved reserves additions replaced 100% of 2008 production. The finding and on-stream cost for net proved reserve additions in North America was $13.08 per barrel of oil equivalent.

    - Total net proved and probable reserves from conventional operations at the end of 2008 amounted to 2.19 billion barrels of crude oil and NGLs and 4.84 trillion cubic feet of natural gas. Total proved and probable net conventional reserves increased in 2008 from 2007.

- Net proved and probable reserve additions from conventional operations equaled 134% of 2008 net production, at a finding and on-stream cost of $14.66 per barrel of oil equivalent. The Company's three-year average net proved and probable finding and on-stream cost was $11.99 per barrel of oil equivalent.
- North America crude oil and NGLs net proved and probable reserve additions equaled to 171% of 2008 net production, while natural gas proved and probable reserve additions equaled 104% of 2008 net production. The finding and on-stream cost for net proved and probable reserve additions in North America was $11.29 per barrel of oil equivalent.
- Using net proved finding and on-stream costs, the Company achieved an overall recycle ratio of 2.3x during 2008.

▪ An independent qualified reserves evaluator evaluated 100% of the Company's Phase 1 to Phase 3 oil sands mining reserves for the Horizon Project under constant prices as at December 31, 2008. The net proved synthetic crude oil reserves increased 11% year over year to 1.95 billion barrels due to price revisions. The net proved and probable synthetic crude oil reserves were 2.94 billion barrels.

▪ The Company repaid $420 million in Q1/09 on the non-revolving syndicated credit facility maturing in October 2009.

▪ Ninth consecutive year of dividend increases. The 2009 quarterly dividend on common shares increased by 5% from C$0.10 to C$0.105 per common share, payable April 1, 2009.

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 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, 2008 (thousands of net acres)	**Drilling activity year ended Dec 31, 2008 (net wells) (1)**
Canadian conventional		
Northeast British Columbia	**2,227**	**27.4**
Northwest Alberta	**1,352**	**81.8**
Northern Plains	**6,452**	**643.3**
Southern Plains	**832**	**111.7**
Southeast Saskatchewan	**130**	**57.7**
Thermal In-situ Oil Sands	**495**	**99.0**
	11,488	**1,020.9**
Horizon Oil Sands Project	**115**	**92.0**
United Kingdom North Sea	**258**	**4.1**
Offshore West Africa	**192**	**4.1**
	12,053	**1,121.1**

(1) Drilling activity includes stratigraphic test and service wells

Drilling activity (number of wells)

	Year Ended Dec 31			
	2008		2007	
	Gross	**Net**	Gross	Net
Crude oil	**728**	**682**	655	592
Natural gas	**411**	**269**	478	383
Dry	**44**	**39**	107	93
Subtotal	**1,183**	**990**	1,240	1,068
Stratigraphic test / service wells	**133**	**131**	256	254
Total	**1,316**	**1,121**	1,496	1,322
Success rate (excluding stratigraphic test / service wells)		**96%**		91%

North America Conventional

North America natural gas

	Quarterly Results			Year End Results	
	Q4/08	Q3/08	Q4/07	**2008**	2007
Natural gas production (mmcf/d)	**1,405**	1,467	1,562	**1,472**	1,643
Net wells targeting natural gas	**43**	62	92	**280**	450
Net successful wells drilled	**41**	62	80	**269**	383
Success rate	**95%**	100%	87%	**96%**	85%

- Annual production for North America natural gas in 2008 was 1,472 mmcf/d, a decrease of 10% from 2007. Q4/08 North America natural gas production decreased 4% from Q3/08 and decreased 10% from Q4/07. The year over year decrease reflected natural declines in production due to the Company's strategic decision to reduce spending on natural gas drilling.
- Canadian Natural targeted 43 net natural gas wells in Q4/08. In Northeast British Columbia, three net wells were drilled, while in Northwest Alberta, 12 net wells were drilled. In the Northern Plains, 18 net wells were drilled, with 10 net wells drilled in the Southern Plains.
- Planned drilling activity for Q1/09 includes 66 net natural gas wells compared to drilling activity for Q1/08 of 167 net natural gas wells.

North America crude oil and NGLs

	Quarterly Results			Year End Results	
	Q4/08	Q3/08	Q4/07	**2008**	2007
Crude oil and NGLs production (bbl/d)	**240,831**	239,973	256,843	**243,826**	246,779
Net wells targeting crude oil	**190**	244	172	**704**	610
Net successful wells drilled	**181**	233	168	**677**	584
Success rate	**95%**	95%	98%	**96%**	96%

- Annual production for North America crude oil and NGLs in 2008 was 243,826 bbl/d, a decrease of 1% from 2007 production. Q4/08 North America crude oil and NGLs production increased modestly from Q3/08 and decreased 6% from Q4/07 levels. The decreases are a reflection of transitioning off the production cycle peaks at Primrose pads, continued polymer conversion at Pelican Lake, and normal declines in primary heavy crude oil production.
- The Primrose East expansion, a new facility located 15 kilometers from the existing Primrose South steam plant and 25 kilometers from the Wolf Lake central processing facility, added production capacity of approximately 40,000 bbl/d of crude oil. Drilling and facility construction is complete, with first steam achieved in September and first production achieved in October 2008 versus the scheduled production target of Q1/09. Primrose East is the second phase of the 325,000 bbl/d thermal growth expansion plan identified to unlock the value from Canadian Natural's thermal crude oil resource base.

- In Q1/09 after initial steaming, Canadian Natural discovered oil seepage at the surface on one of the new multi-well pads at Primrose East. Although the first for the Company, similar issues have been experienced before by another major producer located in the Cold Lake area. The event can be managed and operations can be returned to normal. However, to do so requires that the Company prudently manages the site with observation wells, passive seismic observation wells and other mitigating measures before normal operations resume. Due to the event, the wells at Primrose East were switched in Q1/09 from steaming cycle to the production cycle ahead of schedule. To date, production from the wells has exceeded expectations revealing the promising productivity of the reservoir. Canadian Natural is prudently proceeding with the investigation and working with the regulators. However as a result, 2009 thermal production from Primrose East will be lower than previously forecasted.

- In early 2007, Canadian Natural announced its proposed third phase of the thermal growth plan with a development plan for targeted production capacity of 45,000 bbl/d. Kirby In-Situ Oil Sands Project is located approximately 85 km northeast of Lac La Biche in the Regional Municipality of Wood Buffalo. 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. Subject to regulatory approval, crude oil pricing, and capital costs, the Company may proceed with the detailed engineering and design work.

- Development of new pads and tertiary recovery conversion projects at Pelican Lake continued as expected throughout Q4/08. The Company drilled 18 horizontal wells with plans to drill an additional 58 horizontal wells in 2009. Pelican Lake production averaged approximately 37,000 bbl/d for Q4/08 and Q3/08 compared to approximately 36,000 bbl/d for Q4/07. The response from the polymer flood project continues to be positive and the Company is converting regions currently under waterflood to polymer flood and also expanding the polymer flood to new areas.

- Conventional heavy crude oil production volumes remained constant in Q4/08 compared to Q3/08, with volumes as expected.

- During Q4/08, drilling activity targeted 190 net crude oil wells including 127 wells targeting heavy crude oil, 18 wells targeting Pelican Lake crude oil, 22 wells targeting thermal crude oil and 23 wells targeting light crude oil.

- Planned drilling activity for Q1/09 includes 106 net crude oil wells, excluding stratigraphic test and service wells.

International

	Quarterly Results			Year End Results	
	Q4/08	Q3/08	Q4/07	**2008**	2007
Crude oil production (bbl/d)					
North Sea	**42,991**	42,760	52,709	**45,274**	55,933
Offshore West Africa	**25,748**	24,237	27,688	**26,567**	28,520
Natural gas production (mmcf/d)					
North Sea	**10**	9	13	**10**	13
Offshore West Africa	**12**	14	14	**13**	12
Net wells targeting crude oil	**1.1**	0.6	0.6	**5.5**	7.8
Net successful wells drilled	**1.1**	0.6	0.6	**4.7**	7.8
Success rate	**100%**	100%	100%	**85%**	100%

North Sea

- North Sea production for the quarter was in line with the prior quarter and expectations at 42,991 bbl/d. Both Q3/08 and Q4/08 were impacted by planned maintenance shutdowns, completed within anticipated time frames. On an annual basis North Sea production was 45,274 bbl/d. Annual production levels decreased by 19% from 2007 due to planned maintenance shutdowns at all installations and expected production decline.
- Focus continues on infill drilling and workover opportunities. During 2008, 4.1 net wells were drilled with an additional 1.2 net wells drilling at year end. Production was also enhanced by completion of three workovers during the year.
- In Q1/09, drilling commenced on Deep Banff, a high temperature, high pressure, natural gas well. Canadian Natural's initial net paying interest in the well is 18%. Upon successful discovery the net interest to Canadian Natural increases to 37%. Results are expected in Q2/09.

Offshore West Africa

- Offshore West Africa's crude oil production for the quarter increased by 6% from the prior quarter to 25,748 bbl/d. This was largely due to additional production from Baobab with three wells from the drilling program being on-stream by year end. A fourth and final well will be completed in early 2009. Annual production for 2008 decreased from 2007 by 7% to 26,567 bbl/d as expected production declines were partially offset by a full year of production at the recently completed West Espoir development and the partial restoration of shut in Baobab production late in the year.
- Progress on the Facility Upgrade Project at Espoir to increase capacity of the FPSO continues to progress ahead of schedule and is expected to be completed in Q3/09, an acceleration of three months from the original estimate.
- At the Olowi Project in Offshore Gabon, first oil is expected in late Q1/09 or early Q2/09. During Q4/08, installation of the Conductor Supported Platform Deck and construction of the FPSO were completed. The FPSO arrived on location in February 2009. Two appraisal wells and two production wells have been drilled and development activity is continuing.

Horizon Oil Sands Project

- Canadian Natural continued the construction, commissioning and staged start up of the Horizon Project with first production of synthetic crude oil ("SCO") from Phase 1 achieved February 28, 2009, representing a major milestone achieved by the Company. Currently, the Company is filling all product tanks in preparation for blending and pipeline shipment.
- All major components have been completed and are fully operational with the exception of the Distillate Hydrotreating Plant (Plant 42). The Naphtha and Gas Oil Hydrotreaters – Plants 41 and 43 respectively – are fully operational and currently capable of producing approximately 55,000 bbl/d. Upon completion of Plant 42, the focus will be on reaching full production capacity of 110,000 bbl/d. Plant 42 has now been turned over to operations for commissioning and is targeted to be operational by the end of April subject to any unforeseen start-up issues.
- During the initial stages of the ramp up of production, the production volumes will fluctuate on a weekly basis until the end of Q2/09 when the Company expects to see a steady ramp up to full production by the end of 2009. The Company will work towards full capacity throughout 2009 as the plant continues to be fine tuned to design rates with a focus on safety and reliability.
- In the 2009 start-up year without the benefit of targeted full production capacity, the annual operating cost is forecast to average within C$35-$40 per barrel of SCO. At full production, the Company targets the operating cost for the life of the Horizon Project to be between C$25-$35 per barrel of SCO, a low-cost producer within the oil sands. With an extended period of low commodity prices, additional operating cost and energy savings are expected.
- The Horizon Project was designed, engineered and built in an extremely volatile and inflationary business environment with final construction costs totaling approximately $9.7 billion. This equates to $88,182 per flowing barrel of capacity. Although this is above the initial cost estimate of $6.8 billion the Company targeted in 2005 based on capital efficiency, the cost still comes in well below the industry average for current and future projects with similar facilities.

MARKETING

	Quarterly Results			Year End Results	
	Q4/08	Q3/08	Q4/07	**2008**	2007
Crude oil and NGLs pricing					
WTI [(1)] benchmark price (US$/bbl)	**$ 58.75**	$ 118.13	$ 90.63	**$ 99.65**	$ 72.40
Western Canadian Select blend differential[(2)] from WTI (%)	**33%**	15%	37%	**20%**	32%
Corporate average pricing before risk management (C$/bbl)	**$ 45.81**	$ 102.30	$ 58.03	**$ 82.41**	$ 55.45
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 6.43**	$ 8.78	$ 5.69	**$ 7.71**	$ 6.26
Corporate average pricing before risk management (C$/mcf)	**$ 7.03**	$ 8.82	$ 6.28	**$ 8.39**	$ 6.85

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

(2) Beginning in Q1/08, the Company has quantified the Heavy Differential using the Western Canadian Select ("WCS") blend as the heavy crude oil marker. Prior period amounts have been reclassified.

- In Q4/08, the WCS heavy crude oil differential as a percent of WTI was 33%, compared to 15% in Q3/08. Heavy crude oil differentials widened in Q4/08 due to a weaker worldwide demand for diesel and lower crack spreads, with overall lower demand for crude oil products. Combined with declining heavy crude oil production in Mexico, and increased Venezuelan supply shipments to the Asian markets, US demand has been strong for Canadian heavy crude oil.

- The Company continues its efforts with other industry players to find new markets and to ease the logistical constraints in getting Western Canadian heavy crude oil to new markets, such as the US Gulf Coast. Plans were recently announced to expand the Keystone crude oil pipeline system providing additional capacity to the US Gulf Coast by 2012. Canadian Natural sees this as an important step in its marketing strategy by allowing Canadian heavy crude oil into the US Gulf Coast market and as such has committed 120,000 bbl/d to the Keystone Pipeline US Gulf Coast Expansion for a 20 year period, subject to final regulatory approval for the expansion of the system.

- Canadian Natural has also entered into a 20 year supply agreement with a major US refiner for 100,000 bbl/d of heavy crude oil to US Gulf Coast refineries. These agreements represent a step forward in the defined marketing plan of Canadian Natural to improve the margins on the Company's heavy crude oil production and to reduce the volatility historically experienced in the heavy crude oil market. With the Keystone Pipeline agreement, Canadian Natural will retain full ownership of the resource while gaining access to a key market for Canadian heavy crude oil. The refining capacity in the US Gulf Coast area is approximately 7.5 million bbl/d. The long term supply agreement with a US refiner, which is contingent on the completion of the Keystone Pipeline US Gulf Coast Expansion, ensures a customer at the end of the Keystone Pipeline for a large portion of Canadian Natural's heavy crude oil that is shipped at prevailing US Gulf Coast heavy oil market prices at the points of delivery.

- The Company sees this as a strategic component to its heavy crude oil development which targets an increase to heavy crude oil production capacity from just over 200,000 bbl/d today, to over 500,000 bbl/d over the course of the next 15 years. Canadian heavy crude oil is very competitive against other international grades available in the US Gulf Coast. For Q4/08, the differential for the heavy crude oil marker, Mayan grade, was US$13.90/bbl.

- During Q4/08, the Company contributed approximately 145,000 bbl/d of its heavy crude oil streams to the WCS blend as market conditions resulted in this strategy offering the optimal pricing for bitumen crude oil.

- Natural gas pricing for Q4/08 was volatile compared to prior periods primarily as a result of fluctuations in demand and storage levels. North America natural gas inventory levels increased significantly during the fourth quarter due to increased shale gas production in the US and lower industrial consumption due to the impact of the worldwide financial crisis.

FINANCIAL REVIEW

- The ongoing worldwide economic and financial events have resulted in a significant tightening of the availability of credit and the cost of new sources of liquidity including bank credit facilities and funds derived from debt capital markets. In light of these credit challenges, the Company has undertaken a thorough review of its liquidity sources as well as its exposure to counterparties and has concluded that its capital resources are sufficient to meet ongoing short, medium and long-term commitments. Specifically, the Company continues to believe that its internally generated cash flow from operations supported by the implementation of its hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing 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. Further, the Company believes that its counterparties currently have the financial capacity to settle outstanding obligations in the normal course of business. A brief summary of the Company's strengths are:
  - A diverse asset base geographically and by product - produced in excess of 547,000 boe/d in Q4/08, comprised of approximately 43% natural gas and 57% crude oil - with 95% of production located in G8 countries.
  - Financial stability and liquidity - cash flow from operations of $1.6 billion for Q4/08, with available unused bank lines of $2.1 billion at December 31, 2008.
  - Reduced volatility of commodity prices - a proactive commodity hedging program to reduce the downside risk of volatility in commodity prices supporting cash flow for its capital expenditure program.
  - A strengthening balance sheet with debt to book capitalization of 41% and debt to EBITDA of 1.7 times, both within targeted ranges.
- Under Canadian GAAP, Canadian Natural utilizes the full cost method of accounting for crude oil and natural gas activities and must test for the recoverability of the carrying value of its crude oil and natural gas assets. For Canadian GAAP purposes the future net revenues from crude oil and natural gas assets, based on forward looking strip prices and escalated costs, exceeded the underlying carrying value and no ceiling test impairment was required. The Company is also required to prepare a reconciliation to US GAAP as a footnote to its annual financial statements. Under US GAAP, prescribed rules state that the prices and costs used are to be those at the end of the year, that the future net revenues are to be calculated net of tax, and the future net revenues are to be discounted using a 10% discount rate. As a result, under US GAAP a ceiling test impairment arose which would have reduced property, plant and equipment by $8,665 million in 2008. It is important to note that in January 2009, the SEC announced, among other changes, that the rules relating to single day year end pricing will be changed, effective December 31, 2009, on a go forward basis and will be calculated using a "first day of the month", 12 month average price. Had this change been in effect in 2008, Canadian Natural would not have had a ceiling test impairment under US GAAP.
- In Q1/09 the Company repaid $420 million on the non-revolving syndicated acquisition credit facility maturing in October 2009.
- Ninth consecutive year of dividend increases. The 2009 quarterly dividend on common shares increased by 5% from C$0.10 to C$0.105 per common share, payable April 1, 2009.

OUTLOOK

- Canadian Natural has reduced its capital spending program from $4 billion to $3.2 billion in 2009. In response to the continuing weak commodity prices, particularly in natural gas, the Company has deferred approximately $800 million in expenditures planned for 2009. This, combined with the delayed start up to the Horizon Project and reduced thermal crude oil volumes from Primrose East, will result in production volumes being modestly below previous guidance levels, announced in Q4/08, and accordingly, the Company has revised the 2009 annual corporate guidance.
- The Company forecasts 2009 production levels before royalties to average between 1,272 and 1,328 mmcf/d of natural gas and between 331,000 and 399,000 bbl/d of crude oil and NGLs. Q1/09 production guidance before royalties is forecast to average between 1,365 and 1,394 mmcf/d of natural gas and between 320,000 and 344,000 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, 2008, Canadian Natural retained a qualified independent reserves evaluator, Sproule Associates Limited ("Sproule"), to evaluate 100% of the Company's conventional proved and proved and probable crude oil and natural gas reserves and prepare Evaluation Reports on the Company's total reserves. Canadian Natural has been granted an exemption from 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 United States Securities and Exchange Commission ("SEC") requirements for certain disclosures required under NI 51-101. There are three principal differences between the two standards. The first is the requirement under NI 51-101 to disclose both proved and proved and probable reserves, as well as the related net present value of future net revenues using forecast prices and costs. The second is in the definition of proved reserves; however, as discussed in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), the standards that NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material. The third is the requirement to disclose a gross reserve reconciliation (before the consideration of royalties). Canadian Natural discloses its reserve reconciliation net of royalties in adherence to SEC requirements.
- The Company has disclosed proved reserves using constant prices and costs as mandated by the SEC and has also provided proved and probable reserves under the same parameters as voluntary additional information.
- The SEC requires that oil sands mining reserves be disclosed separately from conventional oil and gas disclosure. Canadian Natural retained a qualified independent reserves evaluator, GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate Phase 1 to Phase 3 of the Company's Horizon Project under SEC Industry Guide 7 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 conventional net reserves

- Crude oil, natural gas and NGLs proved reserves decreased by 0.5% replacing 95% of production. This was accomplished at all-in finding and on-stream costs of $20.68 per barrel of oil equivalent for proved reserves and $14.66 per barrel of oil equivalent for proved and probable reserves.
- In the Evaluation Reports, 53% of crude oil and NGLs proved reserves were assigned to the proved undeveloped category, a 7 percentage point increase from the 46% recorded in 2007.
- In the Evaluation Reports, 23% of natural gas proved reserves were assigned to the proved undeveloped category reflecting the generally shorter lead times required for natural gas developments in Canada.
- In the Evaluation Reports, total proved and probable reserves increased by 2%.

North America conventional net reserves

- Crude oil and NGLs proved reserves increased by 3% replacing 137% of production. Natural gas proved reserves increased by 0.1% replacing 100% of 2008 production.

International conventional net reserves

- North Sea proved reserves decreased by 56 million barrels to 267 million barrels of oil equivalent, which represents 14% of the total proved Company reserves. The decrease was primarily due to changes in year over year pricing.
- In Offshore West Africa proved reserves increased to 158 million barrels in 2008 from 139 million barrels in 2007.

Horizon Oil Sands Project mining net reserves

- The net proved synthetic crude oil reserves increased 11% year over to year to 1.95 billion barrels primarily due to price revisions. The net proved and probable synthetic crude oil reserves were 2.94 billion barrels.

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

	December 31, 2008			
	Proved Developed[2]	Proved Undeveloped[2]	Proved Total[2]	Proved and Probable[3]
Crude oil and NGLs (mmbbl)				
North America	428	520	948	1,599
North Sea	97	159	256	399
Offshore West Africa	107	35	142	191
	632	**714**	**1,346**	**2,189**
Natural gas (bcf)				
North America	2,690	833	3,523	4,619
North Sea	45	22	67	94
Offshore West Africa	89	5	94	131
	2,824	**860**	**3,684**	**4,844**
Total reserves (mmboe)	**1,103**	**857**	**1,960**	**2,996**
Reserve replacement ratio[4] (%)			95%	134%
Cost to develop[5] ($/boe)				
10% discount	$ 0.80	$ 6.94	$ 3.48	$ 3.03
15% discount	$ 0.70	$ 6.04	$ 3.03	$ 2.60
Present value of conventional reserves[6] ($ millions)				
10% discount	$ 12,987	$ 2,200	$ 15,187	$ 19,264
15% discount	$ 11,253	$ 1,164	$ 12,417	$ 15,179

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

	December 31, 2007			
	Proved Developed[2]	Proved Undeveloped[2]	Proved Total[2]	Proved and Probable[3]
Crude oil and NGLs (mmbbl)				
North America	426	494	920	1,545
North Sea	240	70	310	405
Offshore West Africa	70	58	128	186
	736	622	1,358	2,136
Natural gas (bcf)				
North America	2,731	790	3,521	4,602
North Sea	58	23	81	113
Offshore West Africa	53	11	64	88
	2,842	824	3,666	4,803
Total reserves (mmboe)	1,210	759	1,969	2,937
Reserve replacement ratio[4] (%)			110%	87%
Cost to develop[5] ($/boe)				
10% discount	$ 1.25	$ 6.73	$ 3.36	$ 3.20
15% discount	$ 1.09	$ 6.43	$ 3.15	$ 2.99
Present value of conventional reserves[6] ($ millions)				
10% discount	$ 25,767	$ 8,810	$ 34,577	$ 44,286
15% discount	$ 21,924	$ 6,082	$ 28,006	$ 34,604

OIL SANDS MINING RESERVES, NET OF ROYALTIES[1][7]

The following table sets out Canadian Natural's reserves of synthetic crude oil from the Horizon Project Oil Sands leases.

	As at Dec 31, 2008		As at Dec 31, 2007	
	Proved Total	**Proved and Probable**	Proved Total	Proved and Probable
Net reserves, after royalties (mmbbl)				
Synthetic crude oil	**1,946**	**2,944**	1,761	2,680

CONVENTIONAL CRUDE OIL AND NGLs RESERVES RECONCILIATION, NET OF ROYALTIES(1)(8)

Proved reserves (mmbbl)	North America	North Sea	Offshore West Africa	Total
Reserves, December 31, 2006	887	299	130	1,316
Extensions and discoveries	30	-	-	30
Infill drilling	10	6	-	16
Improved recovery	3	-	-	3
Property purchases	1	-	-	1
Property disposals	-	(3)	-	(3)
Production	(77)	(20)	(10)	(107)
Revisions of prior estimates	66	28	8	102
Reserves, December 31, 2007	920	310	128	1,358
Extensions and discoveries	51	-	-	51
Infill drilling	7	6	4	17
Improved recovery	10	-	-	10
Property purchases	-	-	-	-
Property disposals	-	-	-	-
Production	(76)	(17)	(8)	(101)
Economic revisions due to prices	28	(81)	8	(45)
Revisions of prior estimates	8	38	10	56
Reserves, December 31, 2008	**948**	**256**	**142**	**1,346**
Proved and probable reserves (mmbbl)				
Reserves, December 31, 2006	1,502	422	195	2,119
Extensions and discoveries	41	-	-	41
Infill drilling	52	6	-	58
Improved recovery	4	-	-	4
Property purchases	2	6	-	8
Property disposals	-	(3)	-	(3)
Production	(77)	(20)	(10)	(107)
Revisions of prior estimates	21	(6)	1	16
Reserves, December 31, 2007	1,545	405	186	2,136
Extensions and discoveries	76	-	-	76
Infill drilling	9	4	-	13
Improved recovery	23	-	-	23
Property purchases	6	-	-	6
Property disposals	-	-	-	-
Production	(76)	(17)	(8)	(101)
Economic revisions due to prices	59	(45)	8	22
Revisions of prior estimates	(43)	52	5	14
Reserves, December 31, 2008	**1,599**	**399**	**191**	**2,189**

CONVENTIONAL NATURAL GAS RESERVES RECONCILIATION, NET OF ROYALTIES(1)(8)

Proved reserves (bcf)	North America	North Sea	Offshore West Africa	Total
Reserves, December 31, 2006	3,705	37	56	3,798
Extensions and discoveries	134	-	-	134
Infill drilling	124	3	-	127
Improved recovery	8	-	-	8
Property purchases	12	-	-	12
Property disposals	-	-	-	-
Production	(503)	(5)	(4)	(512)
Revisions of prior estimates	41	46	12	99
Reserves, December 31, 2007	3,521	81	64	3,666
Extensions and discoveries	140	-	-	140
Infill drilling	46	(1)	6	51
Improved recovery	6	-	-	6
Property purchases	77	-	-	77
Property disposals	(1)	-	-	(1)
Production	(449)	(4)	(4)	(457)
Economic revisions due to prices	(19)	(56)	6	(69)
Revisions of prior estimates	202	47	22	271
Reserves, December 31, 2008	**3,523**	**67**	**94**	**3,684**
Proved and probable reserves (bcf)				
Reserves, December 31, 2006	4,857	93	99	5,049
Extensions and discoveries	177	-	-	177
Infill drilling	163	3	-	166
Improved recovery	8	-	-	8
Property purchases	17	1	-	18
Property disposals	(1)	-	-	(1)
Production	(503)	(5)	(4)	(512)
Revisions of prior estimates	(116)	21	(7)	(102)
Reserves, December 31, 2007	4,602	113	88	4,803
Extensions and discoveries	182	-	-	182
Infill drilling	58	(3)	-	55
Improved recovery	8	-	-	8
Property purchases	93	-	-	93
Property disposals	(6)	-	-	(6)
Production	(449)	(4)	(4)	(457)
Economic revisions due to prices	(27)	(63)	8	(82)
Revisions of prior estimates	158	51	39	248
Reserves, December 31, 2008	**4,619**	**94**	**131**	**4,844**

The following information for reserves before royalties is provided for comparative purposes:

CONVENTIONAL RESERVES, BEFORE ROYALTIES[1]

	December 31, 2008			
	Proved Developed[2]	**Proved Undeveloped[2]**	**Proved Total[2]**	**Proved and Probable[3]**
Crude oil and NGLs (mmbbl)				
North America	488	569	1,057	1,760
North Sea	97	159	256	399
Offshore West Africa	119	38	157	212
	704	**766**	**1,470**	**2,371**
Natural gas (bcf)				
North America	3,124	953	4,077	5,339
North Sea	45	22	67	94
Offshore West Africa	102	5	107	151
	3,271	**980**	**4,251**	**5,584**
Total reserves (mmboe)	**1,249**	**929**	**2,178**	**3,302**

	December 31, 2007			
	Proved Developed[2]	Proved Undeveloped[2]	Proved Total[2]	Proved and Probable[3]
Crude oil and NGLs (mmbbl)				
North America	505	579	1,084	1,806
North Sea	242	69	311	406
Offshore West Africa	81	67	148	218
	828	715	1,543	2,430
Natural gas (bcf)				
North America	3,330	945	4,275	5,582
North Sea	58	23	81	113
Offshore West Africa	66	13	79	109
	3,454	981	4,435	5,804
Total reserves (mmboe)	1,404	879	2,282	3,397

CONVENTIONAL FINDING AND ON-STREAM COSTS

		2008		2007		2006		Three Year Total
Net reserve replacement expenditures ($ millions)	**$**	**3,475**	$	3,027	$	8,727	**$**	**15,229**
Net reserve additions (mmboe) [9]								
Proved		**168**		212		540		**920**
Proved and probable		**237**		168		865		**1,270**
Finding and on-stream costs ($/boe) [10]								
Proved	**$**	**20.68**	$	14.28	$	16.16	**$**	**16.55**
Proved and probable	**$**	**14.66**	$	18.02	$	10.09	**$**	**11.99**

(1) Reserve estimates and present value calculations are based upon year end constant reference price assumptions as detailed below as well as constant year-end costs.

Crude oil and NGLs		*Company Average Price (C$/bbl)*		*WTI @ Cushing Oklahoma (US$/bbl)*		*Hardisty Heavy 12º API (C$/bbl)*		*North Sea Brent (US$/bbl)*
2008	***$***	***34.51***	***$***	***44.60***	***$***	***26.11***	***$***	***41.76***
2007	*$*	*62.87*	*$*	*96.00*	*$*	*41.70*	*$*	*96.02*
2006	*$*	*51.11*	*$*	*61.05*	*$*	*41.94*	*$*	*58.93*

Natural gas		*Company Average Price (C$/mcf)*		*Henry Hub Louisiana (US$/mmbtu)*		*Alberta AECO C (C$/mmbtu)*		*British Columbia Huntingdon Sumas (C$/mmbtu)*
2008	***$***	***6.51***	***$***	***5.63***	***$***	***6.34***	***$***	***7.48***
2007	*$*	*6.48*	*$*	*6.80*	*$*	*6.52*	*$*	*6.96*
2006	*$*	*6.07*	*$*	*5.52*	*$*	*6.13*	*$*	*6.52*

A foreign exchange rate of US$0.82/C$1.00 was used in the 2008 evaluation; US$1.01/C$1.00 was used in the 2007 evaluation; US$0.86/C$1.00 was used in the 2006 evaluation.

(2) Proved reserve estimates and values were evaluated in accordance with the SEC requirements. The stated reserves have a reasonable certainty of being economically recoverable using year-end prices and costs held constant throughout the productive life of the properties.

(3) Proved and probable reserve estimates and values were evaluated in accordance with the standards of the COGEH and as mandated by NI 51-101. The stated reserves have a 50% probability of equaling or exceeding the indicated quantities and were evaluated using year-end costs and prices held constant throughout the productive life of the properties.

(4) Reserve replacement ratios were calculated using annual net reserve additions comprised of all change categories divided by the net production for that year.

(5) Cost to develop represents total discounted future capital for each reserves category excluding abandonment capital divided by the reserves associated with that category.

(6) Present value of reserves are based upon discounted cash flows associated with prices and operating expenses held constant into the future, before income taxes. Future development costs and associated material well abandonment costs have been applied against future net revenues.

(7) Synthetic crude oil reserves are based on upgrading of the bitumen volumes using technologies implemented at the Horizon Project.

(8) In 2007, revisions of prior estimates includes revisions due to prices.

(9) Reserves additions are comprised of all categories of reserves changes, exclusive of production.

(10) 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 Project.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Forward-Looking Statements

Certain statements 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"), constitutes forward-looking statements. 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.

These statements are not guarantees of future performance and are subject to certain risks and the reader should not place undue reliance on these forward-looking statements as there can be no assurance that the plans, initiatives or expectations upon which they are based will occur.

The forward-looking statements are based on current expectations, estimates and projections about Canadian Natural Resources Limited (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, uncertainties and other factors 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 factors 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, 2008 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2007.

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 and cash flow from operations. 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 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 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 year and three months ended December 31, 2008 in relation to the comparable periods in 2007 and the third quarter of 2008. The accompanying tables form an integral part of this MD&A. This MD&A is dated March 4, 2009. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2007, is available on SEDAR at www.sedar.com.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Year Ended	
	Dec 31 2008	Sep 30 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Revenue, before royalties	**$ 2,511**	$ 4,583	$ 3,200	**$ 16,173**	$ 12,543
Net earnings	**$ 1,770**	$ 2,835	$ 798	**$ 4,985**	$ 2,608
Per common share – basic and diluted	**$ 3.27**	$ 5.25	$ 1.48	**$ 9.22**	$ 4.84
Adjusted net earnings from operations (1)	**$ 697**	$ 963	$ 546	**$ 3,492**	$ 2,406
Per common share – basic and diluted	**$ 1.29**	$ 1.78	$ 1.02	**$ 6.46**	$ 4.46
Cash flow from operations (2)	**$ 1,570**	$ 1,815	$ 1,486	**$ 6,969**	$ 6,198
Per common share – basic and diluted	**$ 2.90**	$ 3.36	$ 2.75	**$ 12.89**	$ 11.49
Capital expenditures, net of dispositions	**$ 1,827**	$ 1,744	$ 1,514	**$ 7,451**	$ 6,425

(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 2008	Sep 30 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Net earnings as reported	**$ 1,770**	$ 2,835	$ 798	**$ 4,985**	$ 2,608
Stock-based compensation (recovery) expense, net of tax [a]	**(145)**	(221)	(11)	**(38)**	134
Unrealized risk management (gain) loss, net of tax [b]	**(1,435)**	(1,750)	593	**(2,112)**	977
Unrealized foreign exchange loss (gain), net of tax [c]	**507**	99	(41)	**698**	(449)
Effect of statutory tax rate and other legislative changes on future income tax liabilities [d]	**-**	-	(793)	**(41)**	(864)
Adjusted net earnings from operations	**$ 697**	$ 963	$ 546	**$ 3,492**	$ 2,406

(a) The Company's employee stock option plan provides for a cash payment option. Accordingly, the intrinsic value of 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 as part of the Horizon Oil Sands Project during the construction period.

(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 swap hedges, 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 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. Income tax rate and other legislative changes in the fourth quarter of 2007 resulted in a reduction of future income tax liabilities of approximately $793 million in North America. Income tax rate changes in the second quarter of 2007 resulted in a reduction of future income tax liabilities of approximately $71 million in North America.

Cash Flow from Operations

($ millions)	Three Months Ended **Dec 31 2008**	Sep 30 2008	Dec 31 2007	Year Ended **Dec 31 2008**	Dec 31 2007
Net earnings	***$ 1,770***	*$ 2,835*	*$ 798*	***$ 4,985***	*$ 2,608*
Non-cash items:					
Depletion, depreciation and amortization	***666***	*659*	*719*	***2,683***	*2,863*
Asset retirement obligation accretion	***19***	*18*	*17*	***71***	*70*
Stock-based compensation (recovery) expense	***(203)***	*(308)*	*(16)*	***(52)***	*193*
Unrealized risk management (gain) loss	***(2,107)***	*(2,506)*	*845*	***(3,090)***	*1,400*
Unrealized foreign exchange loss (gain)	***613***	*113*	*(47)*	***832***	*(524)*
Deferred petroleum revenue tax (recovery) expense	***(5)***	*(7)*	*17*	***(67)***	*44*
Future income tax expense (recovery)	***817***	*1,011*	*(847)*	***1,607***	*(456)*
Cash flow from operations	***$ 1,570***	*$ 1,815*	*$ 1,486*	***$ 6,969***	*$ 6,198*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the year ended December 31, 2008 were $4,985 million compared to $2,608 million for the year ended December 31, 2007. Net earnings for the year ended December 31, 2008 included net unrealized after-tax income of $1,493 million related to the effects of risk management activities, changes in foreign exchange rates and stock-based compensation, and the impact of statutory tax rate and other legislative changes on future income tax liabilities, compared to $202 million for the year ended December 31, 2007. Excluding these items, adjusted net earnings from operations for the year ended December 31, 2008 increased to $3,492 million compared to $2,406 million for the year ended December 31, 2007. The increase in adjusted net earnings from 2007 was primarily due to the impact of higher realized pricing, lower depletion, depreciation and amortization expense, and lower interest and administration expense. These factors were partially offset by higher realized risk management losses, higher royalty and production expense, lower sales volumes, and the impact of the stronger Canadian dollar relative to the US dollar during the first half of the year.

Net earnings for the fourth quarter of 2008 were $1,770 million compared to net earnings of $798 million for the fourth quarter of 2007 and net earnings of $2,835 million for the prior quarter. Net earnings for the fourth quarter of 2008 included net unrealized after-tax income of $1,073 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 $252 million for the fourth quarter of 2007 and $1,872 million for the prior quarter. Excluding these items, adjusted net earnings from operations for the fourth quarter of 2008 were $697 million compared to $546 million for the fourth quarter of 2007 and $963 million for the prior quarter. The increase in adjusted net earnings from the fourth quarter of 2007 was primarily due to the impact of higher realized natural gas pricing, lower depletion, depreciation and amortization expense, lower royalty expense, higher realized risk management gains, and lower interest expense. These factors were partially offset by the impact of lower realized crude oil pricing, higher production expense, and lower sales volumes. The decrease in adjusted net earnings from the prior quarter was primarily due to the impact of lower realized pricing and lower sales volumes, partially offset by the impact of higher realized risk management gains, lower royalty and production expense, and the impact of the weaker 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, 2008 increased to $6,969 million compared to $6,198 million for the year ended December 31, 2007. The increase from the comparable period in 2007 was primarily due to the impact of higher realized pricing and lower interest and administration expense, partially offset by higher realized risk management losses, higher royalty and production expense, higher current income tax expense, lower sales volumes, and the impact of the stronger Canadian dollar relative to the US dollar during the first half of the year.

Cash flow from operations for the fourth quarter of 2008 increased to $1,570 million compared to $1,486 million for the fourth quarter of 2007 and decreased from $1,815 million for the prior quarter. The increase from the fourth quarter of 2007 was primarily due to the impact of higher realized natural gas pricing, lower royalty expense, higher realized risk management gains, lower cash income tax expense, and lower interest expense. These factors were partially offset by the impact of lower realized crude oil pricing, higher production expense, and lower sales volumes. The decrease from the prior quarter was primarily due to the impact of lower realized pricing and lower sales volumes, partially offset by the impact of higher realized risk management gains, lower royalty and production expense, lower cash income tax expense, and the impact of the weaker Canadian dollar relative to the US dollar.

Total production before royalties for the year ended December 31, 2008 decreased 7% to average 564,845 boe/d from 609,206 boe/d for the year ended December 31, 2007. Production for the fourth quarter of 2008 decreased 9% to 547,399 boe/d from 601,908 boe/d for the fourth quarter of 2007 and 1% from 555,356 boe/d for the prior quarter. Total production for the fourth quarter of 2008 was within the Company's previously issued guidance.

For a discussion of the impact of current worldwide financial and economic events, please refer to the "Liquidity and Capital Resources" section of this MD&A.

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 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

($ millions, except per common share amounts)		Dec 31 2007		Sep 30 2007		Jun 30 2007		Mar 31 2007
Revenue, before royalties	$	3,200	$	3,073	$	3,152	$	3,118
Net earnings	$	798	$	700	$	841	$	269
Net earnings per common share								
– Basic and diluted	$	1.48	$	1.30	$	1.56	$	0.50

Net earnings (loss) over the eight most recently completed quarters generally reflected fluctuations in realized crude oil and natural gas prices, fluctuations in sales volumes, the impact of mark-to-market accounting of derivative financial instruments and stock-based compensation, fluctuations in depletion, depreciation and amortization charges and foreign exchange rates, and adjustments to future income tax liabilities due to statutory tax rate and other legislative changes. More specifically, volatility in quarterly net earnings was primarily due to:

- Crude oil pricing

  Crude oil prices reflected fluctuating demand, geopolitical uncertainties and fluctuations in the Heavy Crude Oil Differential from WTI ("Heavy Differential") in North America.

- Natural gas pricing

  Natural gas prices primarily reflected seasonal fluctuations in both the demand for natural gas and inventory storage levels, fluctuations in liquefied natural gas imports into the US, and increased shale gas production in the US.

- Crude oil and NGLs sales volumes

  Crude oil and NGLs sales volumes primarily reflected increased production from the Company's Primrose thermal projects, the results from the Pelican Lake water and polymer flood projects, and development of the Espoir Field. Crude oil and NGLs sales volumes also reflected fluctuations in production from the North Sea and Offshore West Africa due to timing of liftings and maintenance activities and the impact of the shut in of a portion of the Baobab Field production.

- Natural gas sales volumes

  Natural gas sales volumes primarily reflected production declines due to the Company's strategic decision to reduce natural gas drilling activity due to the allocation of capital to higher return crude oil projects, as well as natural decline rates.

- 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.

- Risk management

  Net earnings (loss) have fluctuated 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.

- Changes in income tax expense

  Fluctuations in income tax expense (recovery) include statutory tax rate and other legislative changes substantively enacted or enacted in the various periods.

- Stock-based compensation

  Net earnings (loss) have fluctuated 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 over the eight most recently completed quarters.

- Production expense

  Production expense has fluctuated company wide primarily due to the impact of the demand for services, industry-wide inflationary cost pressures experienced in prior quarters in all segments, fluctuations in product mix, and the impact of seasonal costs that are dependent on weather.

- Depletion, depreciation and amortization

  Depletion, depreciation and amortization expense has fluctuated due to changes in sales volumes, finding and development costs associated with crude oil and natural gas exploration, and estimated future costs to develop the Company's proved undeveloped reserves.

OPERATING HIGHLIGHTS

	Three Months Ended			Year Ended	
	Dec 31 2008	Sep 30 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 45.81**	$ 102.30	$ 58.03	**$ 82.41**	$ 55.45
Royalties	**4.49**	14.17	6.66	**10.48**	5.94
Production expense	**16.33**	17.61	11.53	**16.26**	13.34
Netback	**$ 24.99**	$ 70.52	$ 39.84	**$ 55.67**	$ 36.17
Natural gas ($/mcf) (1)					
Sales price (2)	**$ 7.03**	$ 8.82	$ 6.28	**$ 8.39**	$ 6.85
Royalties	**1.08**	1.55	0.94	**1.46**	1.11
Production expense	**1.06**	1.05	0.91	**1.02**	0.91
Netback	**$ 4.89**	$ 6.22	$ 4.43	**$ 5.91**	$ 4.83
Barrels of oil equivalent ($/boe) (1)					
Sales price (2)	**$ 43.84**	$ 80.60	$ 49.23	**$ 68.62**	$ 49.05
Royalties	**5.37**	12.06	6.21	**9.78**	6.26
Production expense	**12.05**	12.52	8.85	**11.79**	9.75
Netback	**$ 26.42**	$ 56.02	$ 34.17	**$ 47.05**	$ 33.04

(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.

BUSINESS ENVIRONMENT

	Three Months Ended			Year Ended	
	Dec 31 2008	Sep 30 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
WTI benchmark price (US$/bbl)	**$ 58.75**	$ 118.13	$ 90.63	**$ 99.65**	$ 72.40
Dated Brent benchmark price (US$/bbl)	**$ 54.93**	$ 114.96	$ 88.65	**$ 96.99**	$ 72.59
WCS blend differential from WTI (US$/bbl) (1)	**$ 19.13**	$ 17.98	$ 33.74	**$ 20.03**	$ 23.25
WCS blend differential from WTI (%) (1)	**33%**	15%	37%	**20%**	32%
Condensate benchmark price (US$/bbl)	**$ 59.01**	$ 118.57	$ 90.89	**$ 100.10**	$ 72.88
NYMEX benchmark price (US$/mmbtu)	**$ 6.82**	$ 10.11	$ 7.03	**$ 8.95**	$ 6.92
AECO benchmark price (C$/GJ)	**$ 6.43**	$ 8.78	$ 5.69	**$ 7.71**	$ 6.26
US / Canadian dollar average exchange rate	**$ 0.8252**	$ 0.9605	$ 1.0193	**$ 0.9381**	$ 0.9304

(1) Beginning in the first quarter of 2008, the Company has quantified the Heavy Differential using the Western Canadian Select ("WCS") blend as the heavy crude oil marker. Prior period amounts have been reclassified.

Commodity Prices

Crude oil sales contracts in North America are typically based on WTI benchmark pricing. WTI averaged US$99.65 per bbl for the year ended December 31, 2008, an increase of 38% from US$72.40 per bbl for the year ended December 31, 2007. WTI averaged US$58.75 per bbl for the fourth quarter of 2008, a decrease of 35% from US$90.63 per bbl for the fourth quarter of 2007, and a decrease of 50% from US$118.13 per bbl for the prior quarter. During the fourth quarter of 2008, WTI pricing reflected a significant reduction in North American demand for crude oil as a result of worldwide financial and economic events. WTI pricing weakened toward the end of the third quarter and throughout the fourth quarter and traded at a low of US$32.40 per bbl in December 2008, a significant reduction from the all time high for WTI crude oil futures of US$147.27 per bbl reached in July 2008. This decrease in WTI pricing in the fourth quarter of 2008 was partially offset by a weakening in the Canadian dollar compared to the US dollar.

Crude oil sales contracts for the North Sea and Offshore West Africa are typically based on Dated Brent ("Brent") pricing, which was also impacted by worldwide financial and economic events during the fourth quarter of 2008. Brent averaged US$96.99 per bbl for 2008; an increase of 34% compared to US$72.59 per bbl for 2007. In the fourth quarter of 2008, Brent averaged US$54.93 per bbl, a decrease of 38% compared to US$88.65 per bbl for the fourth quarter of 2007, and a decrease of 52% from US$114.96 per bbl for the prior quarter.

The Company's realized crude oil prices increased for the year ended December 31, 2008, benefitting primarily from strong commodity pricing during most of the year and a narrower Heavy Differential. The Heavy Differential averaged 20% for 2008 compared to 32% for 2007. For the fourth quarter of 2008, the Heavy Differential averaged 33% compared to 37% for the fourth quarter of 2007, and 15% for the prior quarter. The narrowing of the Heavy Differential from the comparable periods in 2007 was primarily due to increased demand for heavy crude oil due to reduced refinery cracking margins and worldwide increased demand for diesel. The widening of the Heavy Differential from the prior period reflected seasonal demand fluctuations.

The Company anticipates continued volatility in the crude oil pricing benchmarks due to the unpredictable nature of supply and demand factors, geopolitical events and the global economic slowdown resulting from worldwide financial and economic events. The Heavy Differential is expected to continue to reflect seasonal demand fluctuations and the relatively weaker refinery cracking margins.

NYMEX natural gas prices in 2008 averaged US$8.95 per mmbtu, an increase of 29% from US$6.92 per mmbtu for 2007. For the fourth quarter of 2008, NYMEX natural gas prices averaged US$6.82 per mmbtu, a decrease of 3% from US$7.03 per mmbtu for the fourth quarter of 2007, and a decrease of 33% from US$10.11 per mmbtu for the prior quarter. AECO natural gas prices for the year ended December 31, 2008 increased 23% to average $7.71 per GJ from $6.26 per GJ for the year ended December 31, 2007. For the fourth quarter of 2008, AECO natural gas prices averaged $6.43 per GJ, an increase of 13% from $5.69 per GJ in the fourth quarter of 2007 and a decrease of 27% from $8.78 per GJ for the prior quarter. Fluctuations in natural gas prices from the comparable periods were primarily related to supply and demand dynamics and storage levels. Demand for natural gas in the fourth quarter of 2008 was significantly lower primarily due to the impact of reduced industrial consumption in North America. North America natural gas inventory levels continued to be high during the fourth quarter of 2008 as a result of increased shale gas production in the US and lower overall demand.

Operating, Royalty and Capital Costs

Strong commodity prices over the last several years have resulted in increased demand for oilfield services worldwide. This has led to inflationary operating and capital cost pressures throughout the crude oil and natural gas industry, particularly related to drilling activities and oil sands developments.

The crude oil and natural gas industry is also experiencing cost pressures related to environmental regulations, both in North America and internationally. In Canada, the Federal Government has indicated its intent to develop regulations that would be in effect in 2010 to address industrial greenhouse gas (“GHG”) emissions; however future Federal regulatory requirements remain uncertain. The Federal Government has also outlined national and sectoral reduction targets for several categories of air pollutants. In Alberta, GHG regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually. Two of the Company’s facilities, the Primrose/Wolf Lake in-situ heavy crude oil facilities and the Hays sour natural gas plant, fall under the regulations. Commencing July 1, 2008, the British Columbia carbon tax is being assessed at $10/tonne of CO_2e on fuel consumed in the province, increasing to $30/tonne by July 1, 2012. In the UK, GHG regulations have been in effect since 2005. During Phase 1 (2005 –2007) of the UK National Allocation Plan, the Company operated below its CO_2 allocation. For Phase 2 (2008 – 2012) the Company’s CO_2 allocation has been decreased below the Company’s estimated current operations emissions. The Company does not expect Phase 2 compliance costs to be material. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO_2 emissions at its major facilities and on trading mechanisms to ensure compliance with requirements now in effect.

Continued cost pressures and the final outcome of changes to environmental regulations may adversely impact the Company’s future net earnings, cash flow and capital projects.

The Alberta Government implemented its New Royalty Framework (“NRF”) effective January 1, 2009. The NRF includes a number of changes to royalty rates for natural gas, conventional crude oil, and oil sands production. Under the NRF, royalties payable vary according to commodity prices and the productivity of wells. Leading up to the January 2009 implementation of the NRF, the Alberta Government made several adjustments to the originally proposed formula to address unintended consequences. These adjustments affect royalties payable for certain natural gas and crude oil production wells.

PRODUCT PRICES

	Three Months Ended			Year Ended	
	Dec 31 2008	Sep 30 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Crude oil and NGLs ($/bbl) [(1) (2)]					
North America	**$ 40.39**	$ 99.05	$ 50.49	**$ 77.42**	$ 49.16
North Sea	**$ 63.07**	$ 109.82	$ 83.44	**$ 100.31**	$ 74.99
Offshore West Africa	**$ 65.80**	$ 125.71	$ 81.89	**$ 97.96**	$ 71.68
Company average	**$ 45.81**	$ 102.30	$ 58.03	**$ 82.41**	$ 55.45
Natural gas ($/mcf) [(1) (2)]					
North America	**$ 7.00**	$ 8.83	$ 6.31	**$ 8.41**	$ 6.87
North Sea	**$ 5.19**	$ 3.65	$ 3.62	**$ 4.09**	$ 4.26
Offshore West Africa	**$ 12.54**	$ 11.18	$ 5.49	**$ 10.03**	$ 5.68
Company average	**$ 7.03**	$ 8.82	$ 6.28	**$ 8.39**	$ 6.85
Company average ($/boe) [(1) (2)]	**$ 43.84**	$ 80.60	$ 49.23	**$ 68.62**	$ 49.05
Percentage of gross revenue [(2)] (excluding midstream revenue)					
Crude oil and NGLs	**60%**	70%	66%	**68%**	62%
Natural gas	**40%**	30%	34%	**32%**	38%

(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.

The Company's realized crude oil prices increased 49% to average $82.41 per bbl for the year ended December 31, 2008 from $55.45 per bbl for the year ended December 31, 2007. Realized crude oil prices for the fourth quarter of 2008 decreased 21% to average $45.81 per bbl from $58.03 per bbl for the fourth quarter of 2007, and decreased 55% from $102.30 per bbl for the prior quarter. The Company's realized crude oil prices increased from the year ended December 31, 2007 primarily as a result of higher WTI and Brent benchmark prices during most of 2008 and a narrower Heavy Differential. The decrease from the prior quarter was primarily due to declining WTI and Brent benchmark prices, and a wider Heavy Differential, partially offset by the impact of the weakening Canadian dollar relative to the US dollar.

The Company's realized natural gas price increased 22% to average $8.39 per mcf for the year ended December 31, 2008 from $6.85 per mcf for the year ended December 31, 2007. Realized natural gas prices for the fourth quarter of 2008 increased 12% to average $7.03 per mcf from $6.28 per mcf for the fourth quarter of 2007, and decreased 20% from $8.82 per mcf for the prior quarter. The increase in realized natural gas prices from the comparable periods in 2007 primarily reflected increased AECO benchmark prices and lower liquefied natural gas imports into the US in the first half of 2008, partially offset by higher storage levels due to increased shale gas production in the US. The decrease in realized natural gas prices from the prior quarter was primarily due to the significant reduction in industrial demand during the fourth quarter of 2008 as a result of worldwide financial and economic events.

North America

North America realized crude oil prices increased 57% to average $77.42 per bbl for the year ended December 31, 2008 from $49.16 per bbl for the year ended December 31, 2007. Realized crude oil prices decreased 20% to average $40.39 per bbl for the fourth quarter of 2008 from $50.49 per bbl for the fourth quarter of 2007, and decreased 59% from $99.05 bbl for the prior quarter. The increase from the year ended December 31, 2007 was due to the increase in WTI benchmark pricing and a narrower Heavy Differential. The decrease from the prior quarter was due to declining WTI benchmark pricing and a wider Heavy Differential, partially offset by the impact of the weakening Canadian dollar relative to the US dollar.

In North America, the Company continues to focus on its crude oil marketing strategy, including the development of a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil conversion capacity. During the fourth quarter, the Company contributed approximately 145,000 bbl/d of heavy crude oil blends to the WCS stream. The Company has entered into a 20 year transportation agreement to commit to ship 120,000 bbl/d of heavy sour crude oil on the proposed 500,000 bbl/d Keystone Pipeline US Gulf Coast expansion from Hardisty, Alberta to the US Gulf Coast. Contemporaneously, the Company also entered into a 20 year crude oil purchase and sales agreement to sell 100,000 bbl/d of heavy sour crude oil to a major US refiner. Deliveries under the agreements are expected to commence in 2012 upon completion of the pipeline expansion and are subject to Keystone’s receipt of regulatory approval of the pipeline expansion.

North America realized natural gas prices increased 22% to average $8.41 per mcf for the year ended December 31, 2008 from $6.87 per mcf for the year ended December 31, 2007. Realized North America natural gas prices increased 11% to average $7.00 per mcf for the fourth quarter of 2008 from $6.31 per mcf for the fourth quarter of 2007, and decreased 21% from $8.83 per mcf for the prior quarter. The fluctuations in natural gas prices from the comparable periods in 2007 and the prior quarter were primarily related to the fluctuations in benchmark prices and storage levels.

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

	Dec 31 2008	Sep 30 2008	Dec 31 2007
Wellhead Price (1) (2)			
Light/medium crude oil and NGLs (C$/bbl)	**$ 46.58**	$ 108.13	$ 74.96
Pelican Lake crude oil (C$/bbl)	**$ 40.91**	$ 95.58	$ 47.01
Primary heavy crude oil (C$/bbl)	**$ 37.85**	$ 97.30	$ 43.30
Thermal heavy crude oil (C$/bbl)	**$ 38.68**	$ 97.06	$ 42.76
Natural gas (C$/mcf)	**$ 7.00**	$ 8.83	$ 6.31

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

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

North Sea

North Sea realized crude oil prices increased 34% to average $100.31 per bbl for the year ended December 31, 2008 from $74.99 per bbl for the year ended December 31, 2007. Realized North Sea crude oil prices decreased 24% to average $63.07 per bbl for the fourth quarter of 2008 from $83.44 per bbl for the fourth quarter of 2007, and decreased 43% from $109.82 per bbl for the prior quarter. Realized crude oil prices per bbl in any particular quarter are dependant on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices at the time of lifting. Realized crude oil prices in the North Sea during the fourth quarter were impacted by the declining Brent benchmark pricing, partially offset by the impact of the weakening of the Canadian dollar.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 37% to average $97.96 per bbl for the year ended December 31, 2008 from $71.68 per bbl for the year ended December 31, 2007. Realized Offshore West Africa crude oil prices decreased 20% to average $65.80 per bbl for the fourth quarter of 2008 from $81.89 per bbl for the fourth quarter of 2007, and decreased 48% from $125.71 per bbl for the prior quarter. Realized crude oil prices per bbl in any particular quarter are dependant on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices at the time of lifting. Realized crude oil prices in Offshore West Africa during the fourth quarter were impacted by the declining Brent benchmark pricing, partially offset by the impact of the weakening of the Canadian dollar.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2008	Sep 30 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Crude oil and NGLs (bbl/d)					
North America	**240,831**	239,973	256,843	**243,826**	246,779
North Sea	**42,991**	42,760	52,709	**45,274**	55,933
Offshore West Africa	**25,748**	24,237	27,688	**26,567**	28,520
	309,570	306,970	337,240	**315,667**	331,232
Natural gas (mmcf/d)					
North America	**1,405**	1,467	1,562	**1,472**	1,643
North Sea	**10**	9	13	**10**	13
Offshore West Africa	**12**	14	14	**13**	12
	1,427	1,490	1,589	**1,495**	1,668
Total barrels of oil equivalent (boe/d)	**547,399**	555,356	601,908	**564,845**	609,206
Product mix					
Light/medium crude oil and NGLs	**22%**	21%	23%	**22%**	23%
Pelican Lake crude oil	**7%**	7%	6%	**6%**	6%
Primary heavy crude oil	**16%**	16%	15%	**16%**	15%
Thermal heavy crude oil	**12%**	11%	12%	**12%**	11%
Natural gas	**43%**	45%	44%	**44%**	45%

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2008	Sep 30 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Crude oil and NGLs (bbl/d)					
North America	**210,496**	202,419	217,886	**207,933**	210,769
North Sea	**42,910**	42,665	52,586	**45,182**	55,825
Offshore West Africa	**23,907**	19,050	25,123	**22,641**	26,012
	277,313	264,134	295,595	**275,756**	292,606
Natural gas (mmcf/d)					
North America	**1,198**	1,217	1,327	**1,225**	1,378
North Sea	**10**	9	13	**10**	13
Offshore West Africa	**10**	11	12	**11**	11
	1,218	1,237	1,352	**1,246**	1,402
Total barrels of oil equivalent (boe/d)	**480,409**	470,268	520,887	**483,541**	526,193

Daily production and per bbl statistics are presented throughout this MD&A on a “before royalty” or “gross” basis. Production on an “after royalty” or “net” basis is also presented.

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 and thermal heavy crude oil.

Total production averaged 564,845 boe/d for the year ended December 31, 2008, a 7% decrease from 609,206 boe/d for the year ended December 31, 2007. Production for the fourth quarter of 2008 decreased 9% to average 547,399 boe/d, from 601,908 boe/d for the fourth quarter of 2007, and a 1% decrease from 555,356 boe/d for the prior quarter.

Total crude oil and NGLs production for the year ended December 31, 2008 decreased 5% to 315,667 bbl/d from 331,232 bbl/d for the year ended December 31, 2007. Fourth quarter crude oil and NGLs production decreased 8% to 309,570 bbl/d from 337,240 bbl/d for the fourth quarter of 2007, and increased 1% from 306,970 bbl/d for the prior quarter. The decrease from the comparable periods in 2007 was primarily due to lower production in the North Sea and Offshore West Africa due to the timing of field turnarounds, and in North America due to the cyclic nature of the Company’s thermal production. Crude oil and NGLs production in the fourth quarter of 2008 was above the midpoint of the Company’s previously issued guidance of 300,000 to 316,000 bbl/d.

Natural gas production continued to represent the Company’s largest product offering, accounting for 43% of the Company’s total production in the fourth quarter of 2008. Natural gas production for the year ended December 31, 2008 decreased 10% to average 1,495 mmcf/d compared to 1,668 mmcf/d for the year ended December 31, 2007. Fourth quarter natural gas production decreased 10% to average 1,427 mmcf/d compared to 1,589 mmcf/d for the fourth quarter of 2007 and decreased 4% compared to 1,490 mmcf/d for the prior quarter. The decrease in natural gas production from the comparable periods primarily reflected production declines due to the Company’s strategic decision to reduce natural gas drilling activity to focus on higher return crude oil projects, natural production declines, as well as impact of prolonged cold weather during December 2008. Fourth quarter natural gas production was marginally below the Company’s previously issued guidance of 1,430 to 1,455 mmcf/d.

For 2009, revised annual production guidance is targeted to average between 331,000 and 399,000 bbl/d of crude oil and NGLs and between 1,272 and 1,328 mmcf/d of natural gas. First quarter 2009 production guidance is targeted to average between 320,000 and 344,000 bbl/d of crude oil and NGLs and between 1,365 and 1,394 mmcf/d of natural gas.

North America

North America crude oil and NGLs production for the year ended December 31, 2008 decreased 1% to average 243,826 bbl/d from 246,779 bbl/d for the year ended December 31, 2007. Fourth quarter North America crude oil and NGLs production decreased 6% to average 240,831 bbl/d from 256,843 bbl/d for the fourth quarter of 2007, and increased marginally from 239,973 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.

For the year ended December 31, 2008, natural gas production decreased 10% to 1,472 mmcf/d from 1,643 mmcf/d for the year ended December 31, 2007. For the fourth quarter of 2008, natural gas production decreased 10% to 1,405 mmcf/d from 1,562 mmcf/d for the fourth quarter of 2007, and decreased 4% from 1,467 mmcf/d for the prior quarter. The decrease in natural gas production from the prior periods reflected production declines due to the Company's strategic decision to reduce natural gas drilling activity to focus on higher return crude oil projects, natural production declines, as well as the impact of prolonged cold weather in December 2008.

North Sea

North Sea crude oil production for the year ended December 31, 2008 decreased 19% to 45,274 bbl/d from 55,933 bbl/d for the year ended December 31, 2007. Fourth quarter North Sea crude oil production decreased 18% to 42,991 bbl/d from 52,709 bbl/d for the fourth quarter of 2007 and increased slightly from 42,760 bbl/d for the prior quarter. Fourth quarter production was consistent with the prior quarter, with planned maintenance shutdowns in both quarters. During the fourth quarter of 2008, planned maintenance shutdowns were successfully completed at two of the Ninian Field platforms.

Offshore West Africa

Offshore West Africa crude oil production decreased 7% to 26,567 bbl/d for the year ended December 31, 2008 from 28,520 bbl/d for the year ended December 31, 2007. Fourth quarter Offshore West Africa crude oil production decreased 7% to 25,748 bbl/d from 27,688 bbl/d for the fourth quarter of 2007, and increased 6% from 24,237 bbl/d for the prior quarter. During the fourth quarter of 2008, three new wells from the Baobab Field drilling program came on production, with a fourth well due to come on-stream in the second quarter of 2009.

Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. The related crude oil volumes by segment, which have not been recognized in revenue, were as follows:

(bbl)	**Dec 31 2008**	Sep 30 2008	Dec 31 2007
North America, related to pipeline fill	**761,351**	1,097,526	1,097,526
North Sea, related to timing of liftings	**558,904**	628,642	1,032,723
Offshore West Africa, related to timing of liftings	**609,444**	862,183	8,578
	1,929,699	2,588,351	2,138,827

During the fourth quarter of 2008, the North America pipeline fill was reduced, increasing cash flow from operations by approximately $18 million.

In addition, during the fourth quarter of 2008, an additional 322,000 barrels of crude oil produced in the Company's international operations, which were deferred and included in inventory at September 30, 2008, were sold, increasing cash flow from operations by approximately $43 million.

ROYALTIES

	Three Months Ended			Year Ended	
	Dec 31 2008	Sep 30 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 5.25**	$ 15.76	$ 7.66	**$ 11.99**	$ 7.19
North Sea	**$ 0.12**	$ 0.24	$ 0.19	**$ 0.21**	$ 0.14
Offshore West Africa	**$ 4.71**	$ 26.90	$ 7.59	**$ 14.81**	$ 6.40
Company average	**$ 4.49**	$ 14.17	$ 6.66	**$ 10.48**	$ 5.94
Natural gas ($/mcf) (1)					
North America	**$ 1.09**	$ 1.55	$ 0.95	**$ 1.47**	$ 1.12
Offshore West Africa	**$ 1.26**	$ 2.24	$ 0.52	**$ 1.52**	$ 0.51
Company average	**$ 1.08**	$ 1.55	$ 0.94	**$ 1.46**	$ 1.11
Company average ($/boe) (1)	**$ 5.37**	$ 12.06	$ 6.21	**$ 9.78**	$ 6.26
Percentage of revenue (2)					
Crude oil and NGLs	**10%**	14%	11%	**13%**	11%
Natural gas	**15%**	18%	15%	**17%**	16%
Boe	**12%**	15%	13%	**14%**	13%

(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 crude oil and NGLs royalties per bbl for the year ended December 31, 2008 reflected strong realized crude oil prices for most of the year. Crude oil and NGLs royalties per bbl averaged 15% of gross revenues for 2008, slightly below the anticipated average of 16% to 18% of gross revenue for 2008, due to lower pricing in the fourth quarter of 2008. Due to significant declines in commodity prices late in the year, crude oil and NGLs royalties averaged approximately 13% of gross revenues for the fourth quarter of 2008, compared to 15% for the fourth quarter in 2007 and 16% in the prior quarter.

Natural gas royalties per mcf generally fluctuate with natural gas prices. Due to the impact of lower benchmark prices, natural gas royalties per mcf averaged 18% of gross revenue for 2008, within the anticipated average of 17% to 20% of gross revenue for 2008. Natural gas royalties averaged approximately 16% of revenues for the fourth quarter of 2008 compared to 15% for the fourth quarter of 2007 and 18% for the prior quarter.

North Sea

North Sea government royalties on crude oil were eliminated effective January 1, 2003. The remaining royalty is a gross overriding royalty on the Ninian Field.

Offshore West Africa

Offshore West Africa production is governed by the terms of the various Production Sharing Contracts (“PSCs”). Under the PSCs, revenues are divided into cost recovery oil and profit oil. Cost recovery oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the Government State Oil Companies. Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Governments. The Governments’ share of profit oil attributable to the Company’s equity interest is allocated between royalty expense and current income tax expense in accordance with the PSCs. The Company’s capital investments in the Espoir Fields were fully recovered in the first quarter of 2007, increasing royalty rates and current income taxes in accordance with the terms of the PSCs.

Royalty rates as a percentage of revenue averaged approximately 7% for the fourth quarter of 2008 compared to 9% for the fourth quarter of 2007 and 21% for the prior quarter. Royalty expense in the fourth quarter reflected a higher proportion of Baobab sales in the period, which have lower royalty rates, combined with lower royalty rates on Espoir sales due to the lower realized crude oil price. The decrease was partially offset by the impact of the reduction in the Côte d’Ivoire corporate income tax rate enacted in the first quarter of 2008, which had the effect of increasing the allocation of the Governments’ share of profit oil to royalties.

PRODUCTION EXPENSE

	Three Months Ended			Year Ended	
	Dec 31 2008	Sep 30 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 14.31**	$ 16.23	$ 10.54	**$ 14.96**	$ 12.26
North Sea	**$ 28.77**	$ 29.21	$ 18.95	**$ 26.29**	$ 20.78
Offshore West Africa	**$ 14.47**	$ 7.74	$ 9.32	**$ 10.29**	$ 8.32
Company average	**$ 16.33**	$ 17.61	$ 11.53	**$ 16.26**	$ 13.34
Natural gas ($/mcf) (1)					
North America	**$ 1.04**	$ 1.03	$ 0.90	**$ 1.00**	$ 0.90
North Sea	**$ 1.96**	$ 3.09	$ 1.50	**$ 2.51**	$ 2.17
Offshore West Africa	**$ 2.51**	$ 1.58	$ 1.89	**$ 1.61**	$ 1.48
Company average	**$ 1.06**	$ 1.05	$ 0.91	**$ 1.02**	$ 0.91
Company average ($/boe) (1)	**$ 12.05**	$ 12.52	$ 8.85	**$ 11.79**	$ 9.75

(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, 2008 increased 22% to $14.96 per bbl from $12.26 per bbl for the year ended December 31, 2007. Fourth quarter North America crude oil and NGLs production expense increased 36% to $14.31 per bbl from $10.54 per bbl for the fourth quarter of 2007 and decreased 12% from $16.23 per bbl for the prior quarter. The increase in production expense per bbl from the comparable periods in 2007 was primarily a result of the higher cost of natural gas for fuel for the Company’s thermal operations and increased property tax and power costs. The decrease in the fourth quarter of 2008 compared to the prior quarter was a result of the timing of steam cycles at thermal properties, partially offset by the impact of lower production volumes on the fixed cost portion of production costs.

North America natural gas production expense for the year ended December 31, 2008 increased 11% to $1.00 per mcf from $0.90 per mcf for the year ended December 31, 2007. Fourth quarter North America natural gas production expense increased 16% to $1.04 per mcf from $0.90 per mcf for the fourth quarter of 2007 and increased slightly from $1.03 per mcf for the prior quarter. The increase in production expense per mcf from the comparable periods was primarily a result of lower production volumes on the fixed cost portion of production costs. In addition, the increase from the prior quarter was impacted by prolonged cold weather in December.

North Sea

North Sea crude oil production expense increased on a per bbl basis from the comparable periods in 2007 due to lower production volumes on a relatively fixed operating cost base as well as due to higher planned maintenance costs.

Offshore West Africa

Offshore West Africa crude oil production expense increased on a per bbl basis from the prior quarter primarily due to the impact of the timing of liftings at the Baobab and Espoir Fields, resulting in a greater proportion of relatively higher fixed cost Baobab sales in the quarter. The increase over the comparable periods in 2007 was largely due to lower production volumes on a relatively fixed operating cost base.

MIDSTREAM

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2008**	Sep 30 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Revenue	**$ 17**	$ 20	$ 19	**$ 77**	$ 74
Production expense	**6**	6	6	**25**	22
Midstream cash flow	**11**	14	13	**52**	52
Depreciation	**2**	2	2	**8**	8
Segment earnings before taxes	**$ 9**	$ 12	$ 11	**$ 44**	$ 44

The Company's midstream assets consist of three crude oil pipeline systems and a 50% working interest in an 84-megawatt cogeneration plant at Primrose. Approximately 80% of the Company's heavy crude oil production is transported to international mainline liquid pipelines via the 100% owned and operated ECHO Pipeline, the 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold Lake Pipeline. The midstream pipeline assets allow the Company to control the transport of its own production volumes as well as earn third party revenue. This transportation control enhances the Company's ability to manage the full range of costs associated with the development and marketing of its heavier crude oil.

DEPLETION, DEPRECIATION AND AMORTIZATION (1)

	Three Months Ended			Year Ended	
	Dec 31 2008	Sep 30 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Expense ($ millions) (2)	**$ 664**	$ 657	$ 717	**$ 2,675**	$ 2,855
$/boe (3)	**$ 13.20**	$ 12.93	$ 12.99	**$ 12.97**	$ 12.84

(1) DD&A excludes depreciation on midstream assets.

(2) Amounts include the impact of intersegment eliminations.

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

Depletion, Depreciation and Amortization ("DD&A") for the year ended December 31, 2008 and the fourth quarter decreased in total from the comparable periods in 2007, primarily due to the impact of lower sales volumes. The increase from the prior quarter was primarily due to the impact of the weaker Canadian dollar on DD&A charges in the UK, as well as an increase in sales volumes during the fourth quarter in Offshore West Africa, where DD&A rates are higher.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three Months Ended			Year Ended	
	Dec 31 2008	Sep 30 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Expense ($ millions)	**$ 19**	$ 18	$ 17	**$ 71**	$ 70
$/boe (1)	**$ 0.38**	$ 0.35	$ 0.31	**$ 0.34**	$ 0.32

(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. Accretion expense for the year ended December 31, 2008 and the fourth quarter was consistent with the comparable periods.

ADMINISTRATION EXPENSE

	Three Months Ended			Year Ended	
	Dec 31 2008	Sep 30 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Expense ($ millions)	**$ 46**	$ 46	$ 42	**$ 180**	$ 208
$/boe (1)	**$ 0.91**	$ 0.91	$ 0.76	**$ 0.87**	$ 0.93

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

Administration expense for the year ended December 31, 2008 decreased from the year ended December 31, 2007 primarily due to decreased staffing costs, including costs related to the Company's share bonus program, as well as due to lower office lease costs.

STOCK-BASED COMPENSATION (RECOVERY) EXPENSE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2008**	Sep 30 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
(Recovery) expense	**$ (203)**	$ (308)	$ (16)	**$ (52)**	$ 193

The Company's Stock Option Plan (the "Option Plan") provides current employees (the "option holders") with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. The design of the Option Plan balances the need for a long-term compensation program to retain employees with the benefits of reducing the impact of dilution on current Shareholders and the reporting of the obligations associated with stock options. Transparency of the cost of the Option Plan is increased as changes in the intrinsic value of outstanding stock options are recognized each period. The cash payment feature provides option holders with substantially the same benefits and allows them to realize the value of their options through a simplified administration process.

The Company recorded a $52 million ($38 million after-tax) stock-based compensation recovery for the year ended December 31, 2008 as a result of a 33% decrease in the Company's share price for the year ended December 31, 2008 (Company's share price as at: December 31, 2008 – C$48.75; September 30, 2008 – C$73.00; December 31, 2007 – C$72.58), offset by the impact of normal course graded vesting of options granted in prior periods and the impact of vested options exercised or surrendered during the period. For the three months ended December 31, 2008, the Company recorded a $203 million ($145 million after-tax) stock-based compensation recovery, primarily due to a 33% decrease in the Company's share price during the fourth quarter of 2008. As required by GAAP, the Company records a liability for potential cash payments to settle its outstanding employee stock options each reporting period based on the difference between the exercise price of the stock options and the market price of the Company's common shares, pursuant to a graded vesting schedule. The liability is revalued quarterly to reflect changes in the market price of the Company's common shares and the options exercised or surrendered in the period, with the net change recognized in net earnings, or capitalized during the construction period in the case of the Horizon Project. For the year ended December 31, 2008, the Company recorded a $23 million recovery of previously capitalized stock-based compensation on the Horizon Project (December 31, 2007 – $58 million capitalized).

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, 2008. In periods when substantial stock price changes occur, the Company's earnings are subject to significant volatility. The Company utilizes its stock-based compensation plan to attract and retain employees in a competitive environment. All employees participate in this plan.

For the year ended December 31, 2008, the Company paid $207 million for stock options surrendered for cash settlement (December 31, 2007 – $375 million).

INTEREST EXPENSE

	Three Months Ended			Year Ended	
($ millions, except per boe amounts)	**Dec 31 2008**	Sep 30 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Expense, gross	**$ 158**	$ 150	$ 160	**$ 609**	$ 632
Less: capitalized interest, Horizon Project	**135**	125	109	**481**	356
Expense, net	**$ 23**	$ 25	$ 51	**$ 128**	$ 276
$/boe [1]	**$ 0.45**	$ 0.49	$ 0.92	**$ 0.62**	$ 1.24
Average effective interest rate	**5.0%**	5.0%	5.5%	**5.1%**	5.5%

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

Gross interest expense and the Company's average effective interest rate decreased in the year ended December 31, 2008 from the comparable period in 2007 primarily due to a decrease in short term borrowing rates during the last half of 2008 and the impact of the stronger Canadian dollar relative to the US dollar during the first half of 2008.

On commencement of operations of Phase 1 of the Horizon Project, interest capitalization will cease on this Phase, increasing interest expense accordingly.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, currency and interest rate exposures. The Company's risk management program is not used for speculative purposes.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2008**	Sep 30 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Crude oil and NGLs financial instruments	**$ (179)**	$ 792	$ 308	**$ 2,020**	$ 505
Natural gas financial instruments	**-**	16	(127)	**(21)**	(343)
Foreign currency contracts	**(122)**	(17)	-	**(139)**	-
Realized (gain) loss	**$ (301)**	$ 791	$ 181	**$ 1,860**	$ 162
Crude oil and NGLs financial instruments	**$ (2,112)**	$ (2,423)	$ 770	**$ (3,104)**	$ 1,244
Natural gas financial instruments	**(13)**	(68)	75	**16**	156
Foreign currency contracts	**18**	(15)	-	**(2)**	-
Unrealized (gain) loss	**$ (2,107)**	$ (2,506)	$ 845	**$ (3,090)**	$ 1,400
Net (gain) loss	**$ (2,408)**	$ (1,715)	$ 1,026	**$ (1,230)**	$ 1,562

The net realized (gain) loss from crude oil and natural gas financial instruments would have (increased) decreased the Company's average realized prices as follows:

	Three Months Ended			Year Ended	
	Dec 31 2008	Sep 30 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Crude oil and NGLs ($/bbl) (1)	**$ (6.16)**	$ 28.37	$ 9.99	**$ 17.45**	$ 4.18
Natural gas ($/mcf) (1)	**$ -**	$ 0.11	$ (0.87)	**$ (0.04)**	$ (0.56)

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

Complete details related to outstanding derivative financial instruments at December 31, 2008 are disclosed in note 11 to the Company's unaudited interim consolidated financial statements.

The commodity derivative financial instruments currently outstanding have not been designated as hedges for accounting purposes (the "non-designated hedges"). The fair value of these non-designated hedges is based on prevailing forward commodity prices in effect at the end of each reporting period and is reflected in risk management activities in consolidated net earnings. The cash settlement amount of the risk management derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the derivative financial instruments, as compared to their mark-to-market value at December 31, 2008.

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 gain of $3,090 million ($2,112 million after-tax) on its risk management activities for the year ended December 31, 2008, including a $2,107 million ($1,435 million after-tax) net unrealized gain for the fourth quarter of 2008 (September 30, 2008 – unrealized gain of $2,506 million, $1,750 million after-tax; December 31, 2007 – unrealized loss of $845 million, $593 million after-tax).

FOREIGN EXCHANGE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2008**	Sep 30 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Net realized (gain) loss	**$ (51)**	$ (40)	$ -	**$ (114)**	$ 53
Net unrealized loss (gain) (1)	**613**	113	(47)	**832**	(524)
Net loss (gain)	**$ 562**	$ 73	$ (47)	**$ 718**	$ (471)

(1) Amounts are reported net of the hedging effect of cross currency swap hedges as described in Risk Management Activities.

The Company's operating results are affected by fluctuations in the exchange rates between the Canadian dollar, US dollar, and UK pound sterling. A majority of the Company's revenue is based on reference to US dollar benchmark prices. An increase in the value of the Canadian dollar in relation to the US dollar results in decreased revenue from the sale of the Company's production. Conversely, a decrease in the value of the Canadian dollar in relation to the US dollar results in increased revenue from the sale of the Company's production. Production expenses and future income tax liabilities in the North Sea are subject to foreign currency fluctuations due to changes in the exchange rate of the UK pound sterling to the US dollar. The value of the Company's US dollar denominated debt is also impacted by the value of the Canadian dollar in relation to the US dollar.

The net unrealized foreign exchange loss for the year ended December 31, 2008 was primarily related to the weakening of the Canadian dollar in relation to the US dollar with respect to the US dollar denominated debt, offset by the impact of the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars. Included in the net unrealized loss for the year ended December 31, 2008 was an unrealized gain of $449 million (year ended December 31, 2007 – unrealized loss of $350 million) related to the impact of cross currency swap hedges. The net realized foreign exchange gain for the year ended December 31, 2008 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 and the repayment of US dollar denominated debt. The Canadian dollar ended the fourth quarter at US$0.8166 compared to US$0.9435 at September 30, 2008 (December 31, 2007 – US$1.0120).

TAXES

($ millions, except income tax rates)	Three Months Ended Dec 31 2008	Sep 30 2008	Dec 31 2007	Year Ended Dec 31 2008	Dec 31 2007
Current	**$ 27**	$ 52	$ 16	**$ 245**	$ 121
Deferred	**(5)**	(7)	17	**(67)**	44
Taxes other than income tax	**$ 22**	$ 45	$ 33	**$ 178**	$ 165
North America	**$ -**	$ 6	$ 31	**$ 33**	$ 96
North Sea	**12**	121	65	**340**	210
Offshore West Africa	**12**	44	27	**128**	74
Current income tax	**24**	171	123	**501**	380
Future income tax	**817**	1,011	(847)	**1,607**	(456)
	841	1,182	(724)	**2,108**	(76)
Income tax rate and other legislative changes (1) (2) (3)	**-**	-	793	**41**	864
	$ 841	$ 1,182	$ 69	**$ 2,149**	$ 788
Effective income tax rate before non-recurring benefits	**32.2%**	29.4%	93.2%	**30.3%**	31.1%

(1) Includes the effect of a one time 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.

(2) Includes the effect of a one time recovery of $793 million due to Canadian Federal income tax rate reductions and other legislative changes substantively enacted or enacted during the fourth quarter of 2007.

(3) Includes the effect of a one time recovery of $71 million due to Canadian Federal income tax rate reductions enacted during the second quarter of 2007.

Taxes other than income tax primarily includes current and deferred petroleum revenue tax ("PRT"). PRT 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, North America and North Sea current income taxes will vary depending on available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Dec 31 2008	Sep 30 2008	Dec 31 2007	Year Ended Dec 31 2008	Dec 31 2007
Expenditures on property, plant and equipment					
Net property acquisitions	**$ 34**	$ 47	$ (107)	**$ 336**	$ (39)
Land acquisition and retention	**18**	32	15	**86**	95
Seismic evaluations	**22**	40	17	**107**	124
Well drilling, completion and equipping	**505**	421	341	**1,664**	1,642
Production and related facilities	**382**	311	390	**1,282**	1,205
Total net reserve replacement expenditures	**961**	851	656	**3,475**	3,027
Horizon Project:					
Phase 1 construction costs	**557**	635	691	**2,732**	2,740
Phase 1 operating and capital inventory	**5**	27	-	**87**	-
Phase 1 commissioning costs	**110**	84	-	**277**	-
Phases 2/3 costs	**94**	83	33	**336**	124
Capitalized interest, stock-based compensation and other	**78**	46	108	**480**	437
Total Horizon Project [2]	**844**	875	832	**3,912**	3,301
Midstream	**3**	2	2	**9**	6
Abandonments [3]	**15**	10	16	**38**	71
Head office	**4**	6	8	**17**	20
Total net capital expenditures	**$ 1,827**	$ 1,744	$ 1,514	**$ 7,451**	$ 6,425
By segment					
North America	**$ 486**	$ 578	$ 570	**$ 2,344**	$ 2,428
North Sea	**117**	78	44	**319**	439
Offshore West Africa	**358**	195	43	**811**	159
Other	**-**	-	(1)	**1**	1
Horizon Project	**844**	875	832	**3,912**	3,301
Midstream	**3**	2	2	**9**	6
Abandonments [3]	**15**	10	16	**38**	71
Head office	**4**	6	8	**17**	20
Total	**$ 1,827**	$ 1,744	$ 1,514	**$ 7,451**	$ 6,425

(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 Horizon Project 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, 2008 were $7,451 million compared to $6,425 million for the year ended December 31, 2007. Net capital expenditures for the fourth quarter of 2008 were $1,827 million compared to $1,514 million for the fourth quarter of 2007 and $1,744 million for the prior quarter. The capital expenditures primarily reflected the continued progress on the Company's larger, future growth projects, most notably the Horizon Project, Primrose East, and Gabon, offset by the effects of an overall strategic reduction in the North America natural gas drilling program.

For the year ended December 31, 2008, the Company drilled a total of 1,121 net wells consisting of 269 natural gas wells, 682 crude oil wells, 131 stratigraphic test and service wells and 39 wells that were dry. This compared to 1,322 net wells drilled for the year ended December 31, 2007. The Company achieved an overall success rate of 96% for the year ended December 31, 2008, excluding stratigraphic test and service wells, compared to 91% for the year ended December 31, 2007**.**

For the fourth quarter of 2008, the Company drilled a total of 331 net wells consisting of 41 natural gas wells, 182 crude oil wells, 97 stratigraphic test and service wells and 11 wells that were dry. This compared to 271 net wells drilled for the fourth quarter of 2007 and 315 net wells for the prior quarter. The Company achieved an overall success rate of 95% for the fourth quarter of 2008, excluding stratigraphic test and service wells, compared to 94% for the fourth quarter of 2007 and 96% for the prior quarter**.**

North America

North America, excluding the Horizon Project, accounted for approximately 32% of the total capital expenditures for the year ended December 31, 2008 compared to 39% for the year ended December 31, 2007.

During the year ended December 31, 2008, the Company targeted 280 net natural gas wells, including 27 wells in Northeast British Columbia, 104 wells in the Northern Plains region, 70 wells in Northwest Alberta, and 79 wells in the Southern Plains region. The Company also targeted 704 net crude oil wells during the same period. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 415 heavy crude oil wells, 110 Pelican Lake crude oil wells, 74 thermal crude oil wells and 7 light crude oil wells were targeted. Another 98 wells targeting light crude oil were drilled outside the Northern Plains region.

Due to significant differences in relative commodity prices between crude oil and natural gas throughout most of 2008, 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 2007 and 2008 and as a result of royalty changes under the Alberta NRF, natural gas drilling activities have been reduced to manage overall capital spending. 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 averaged approximately 64,000 bbl/d for the fourth quarter of 2008 compared to 74,000 bbl/d for the fourth quarter of 2007 and approximately 61,000 bbl/d for the prior quarter.

The Primrose East expansion, a new facility located 15 kilometers from the existing Primrose South steam plant and 25 kilometers from the Wolf Lake central processing facility, was completed and first steaming commenced in September 2008, with first production achieved in the fourth quarter of 2008. Subsequent to December 31, 2008, operational issues on one of the pads has caused steaming to cease on all well pads in the Primrose East project area and the Company is working on rectifying the issues.

The next planned phase of the Company's In-Situ Oil Sands Assets expansion is the Kirby project located 120 kilometers north of the existing Primrose facilities. During 2007, the Company filed a combined application and Environmental Impact Assessment for this project with Alberta Environment and the Alberta Energy and Utilities Board. Final corporate sanction and project scope will be impacted by environmental regulations and their associated costs. Subject to regulatory approval, crude oil pricing, and capital costs, the Company may proceed with the detailed engineering and design work.

Development of new pads and secondary recovery conversion projects at Pelican Lake continued as expected throughout the fourth quarter of 2008. Drilling consisted of 18 horizontal wells in the fourth quarter. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 37,000 bbl/d for the third and fourth quarters of 2008 compared to approximately 36,000 bbl/d for the fourth quarter of 2007.

For the first quarter of 2009, the Company's overall planned drilling activity in North America is expected to be comprised of 66 natural gas wells and 106 crude oil wells, excluding stratigraphic and service wells.

Horizon Project

The Company continued the construction, commissioning and staged start up of the Horizon Project with first production of synthetic crude oil from Phase 1 achieved February 28, 2009, representing a major milestone achieved by the Company. Currently, the Company is filling all product tanks in preparation for blending and pipeline shipment.

All major components have been completed and are fully operational with the exception of the Distillate Hydrotreating Plant (Plant 42). The Naphtha and Gas Oil Hydrotreaters (Plants 41 and 43 respectively) are fully operational and currently capable of producing approximately 55,000 bbl/d. Upon completion of Plant 42, the focus will be on reaching full production capacity of 110,000 bbl/d. Plant 42 has now been turned over to operations for commissioning and is targeted to be operational by the end of April subject to any unforeseen start up issues.

During the initial stages of the ramp-up of production, the production volumes will fluctuate on a weekly basis until the end of the second quarter of 2009 when the Company expects to see a steady ramp up to full production by the end of 2009. The Company will work towards full capacity throughout 2009 as the plant continues to be fine tuned to design rates with a focus on safety and reliability.

The Horizon Project was designed, engineered, and constructed in an extremely volatile and inflationary business environment with final construction costs totaling approximately $9.7 billion.

North Sea

In the fourth quarter of 2008, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. At the end of the fourth quarter of 2008, 1.2 net wells were in progress.

A workover was completed at the Columba E Field during the fourth quarter, increasing production. The Company also continued with its strategy of long-term investment in the facilities and infrastructure at the Ninian Field, completing turnarounds at two of the platforms during the fourth quarter within planned timeframes.

Offshore West Africa

During the fourth quarter of 2008, 1.1 net wells were drilled, with an additional 0.9 net wells drilling at the end of the quarter.

At Baobab, the second and third wells in the current-year Baobab drilling program were completed in the quarter, with the final well due to be completed in the second quarter of 2009. At the 90% owned and operated Olowi Field in offshore Gabon, the Conductor Supported Platform was installed in early November, construction was completed on the floating production storage and offtake vessel ("FPSO"), which arrived on location in February 2009, and construction continued on the wellhead towers and subsea facilities. First crude oil is targeted for late in the first quarter or early in the second quarter of 2009.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Dec 31 2008**		Sep 30 2008		Dec 31 2007
Working capital (deficit) [1]	**$**	**392**	$	(1,103)	$	(1,382)
Long-term debt [2] [3]	**$**	**13,016**	$	11,633	$	10,940
Share capital	**$**	**2,768**	$	2,761	$	2,674
Retained earnings		**15,344**		13,628		10,575
Accumulated other comprehensive income		**262**		116		72
Shareholders' equity	**$**	**18,374**	$	16,505	$	13,321
Debt to book capitalization [3] [4]		**41%**		41%		45%
Debt to market capitalization [3] [5]		**33%**		23%		22%
After tax return on average common shareholders' equity [6]		**33%**		29%		22%
After tax return on average capital employed [3] [7]		**19%**		16%		12%

(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 *(2008 – $420 million; 2007 and 2006 – $nil).*

(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 $10,678 million in average capital employed related to the Horizon Project (September 30, 2008 – $9,725 million; December 31, 2007 – $7,001 million).

At December 31, 2008, 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, 2007 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 ongoing worldwide financial and economic events have resulted in a significant tightening of the availability and cost of new sources of liquidity including bank credit facilities and funds derived from debt capital markets. In light of these credit challenges, the Company has undertaken a thorough review of its liquidity sources as well as its exposure to counterparties and has concluded that its capital resources are sufficient to meet ongoing short-, medium- and long-term commitments. Specifically, the Company continues to believe that its internally generated cash flow from operations supported by the implementation of its 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. Further, the Company believes that its counterparties currently have the financial capacity to settle outstanding obligations in the normal course of business.

On an ongoing basis, the Company continues to focus on the following areas:

- Monitoring cash flow from operations, which is the primary source of funds;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages;
- Monitoring credit markets, governments, world banks and the Company's bank syndicates to identify associated risks and exposures;
- Maintaining an active commodity risk management program that manages exposure to crude oil and natural gas price volatility. The Company believes this is an effective tool to manage short- and medium-term changes in spot commodity prices. The Company also monitors its commodity risk management counterparties to ensure they are in position to settle obligations within the contractually agreed terms of settlement;
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place to minimize the impact in the event of default; and
- Monitoring the Company's 2009 capital and operating plans to provide the required flexibility to deal with commodity price volatility, commitments in respect of capital and operating expenditures, and commitments to retire its non-revolving bank credit facility maturing in October 2009. The Company actively manages the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner. The Company continued the construction, commissioning and staged start up of the Horizon Project with first production of synthetic crude oil from Phase 1 achieved February 28, 2009.

At the end of the fourth quarter of 2008, the Company had $2,082 million of available credit under its bank credit facilities, which together with cash flow from operating activities to be generated in 2009 supported by its commodity risk management program and the ability to actively manage the capital expenditure programs, is forecasted to be sufficient to repay the $2,350 million non-revolving bank credit facility maturing October 2009. Further, the Company's current debt ratings are BBB (high) with a negative 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, 2008 are discussed below and in note 4 to the Company's unaudited interim consolidated financial statements.

At December 31, 2008, the Company's working capital was $392 million, excluding the current portion of long-term debt and including the current portion of the net mark-to-market asset for risk management derivative financial instruments of $1,851 million and the current portion of the stock-based compensation liability of $159 million, together with related future income tax liabilities of $585 million. The cash settlement amount of the risk management derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the derivative financial instruments, as compared to their mark-to-market value at December 31, 2008. The settlement of the stock-based compensation liability is dependent upon both the surrender of vested stock options for cash settlement by employees and the value of the Company's share price at the time of surrender.

Long-term debt was $13,016 million at December 31, 2008, resulting in a debt to book capitalization ratio of 41% (September 30, 2008 – 41%; December 31, 2007 – 45%). This ratio is near the midpoint of the 35% to 45% range targeted by management, including the impact of capital spending on the Horizon Project. 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 2009 and 2010 at prices that protect investment returns to ensure ongoing balance sheet strength and the completion of its capital expenditure programs. In the future, the Company may also consider the divestiture of certain non-strategic and non-core properties to gain additional balance sheet flexibility.

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, 2008, in accordance with the policy, approximately 6% of budgeted crude oil volumes are hedged using collars for 2009 and approximately 33% of budgeted natural gas volumes are hedged using collars for the first quarter of 2009. In addition, 92,000 bbl/d of crude oil volumes are protected by put options for 2009 at a strike price of US$100.00 per bbl.

The Company had the following net commodity derivative financial instruments outstanding at December 31, 2008:

	Remaining term	Volume	Weighted average price	Index
Crude oil				
Crude oil price collars	Jan – Dec 2009	25,000 bbl/d	US$70.00 – US$111.56	WTI
	Apr – Jun 2009	4,000 bbl/d	US$70.00 – US$90.00	WTI
Crude oil puts	Jan – Dec 2009	92,000 bbl/d	US$100.00	WTI
Natural gas				
Natural gas price collars (1)	Jan – Mar 2009	500,000 GJ/d	C$6.00 – C$8.63	AECO

(1) Subsequent to December 31, 2008, the Company entered into 220,000 GJ/d of C$6.00 – C$8.00 natural gas AECO collars for the period January to December 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.

In addition to the financial derivatives noted above, subsequent to December 31, 2008, the Company entered into natural gas physical sales contracts for 400,000 GJ/d at an average fixed price of C$5.29 per GJ at AECO for the period April to December 2009.

Long-term debt

As at December 31, 2008, the Company had in place unsecured bank credit facilities of $6,232 million, comprised of:

- a $125 million demand credit facility;
- a non-revolving syndicated credit facility of $2,350 million maturing October 2009, as discussed below;
- 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.

In conjunction with the closing of the acquisition of ACC in November 2006, the Company executed a $3,850 million, non-revolving syndicated credit facility maturing October 2009. In March 2007, $1,500 million was repaid, reducing the facility to $2,350 million. During 2009, the Company plans to fully retire this facility from its existing uncommitted borrowing capacity under its other long-term bank credit facilities of $2,050 million, supported by cash flow from operating activities, including the commodity risk management activities. In accordance with these plans, and repayments of $420 million made subsequent to December 31, 2008 on this facility, $420 million has been classified as current.

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $372 million, including $300 million related to the Horizon Project, were outstanding at December 31, 2008.

Medium-term notes

The Company has $2,600 million remaining on its outstanding $3,000 million base shelf prospectus filed in September 2007 that allows for the issue of medium-term notes in Canada until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

Senior unsecured notes

During the second quarter of 2008, US$31 million of the senior unsecured notes were repaid.

US dollar debt securities

During the fourth quarter of 2008, the Company terminated the interest rate swaps that had been designated as a fair value hedge of US$350 million of 5.45% unsecured notes due October 2012. Accordingly, the Company ceased revaluing the related debt from the date of termination of the interest rate swaps for subsequent changes in fair value. The fair value adjustment of $20 million at the date of termination is being amortized to interest expense over the remaining term of the debt.

During the third quarter of 2008, US$8 million of US dollar debt securities were repaid.

In January 2008, the Company issued US$1,200 million of unsecured notes under a US base shelf prospectus, comprised of US$400 million of 5.15% unsecured notes due February 2013, US$400 million of 5.90% unsecured notes due February 2018, and US$400 million of 6.75% unsecured notes due February 2039. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these securities, the Company has US$1,800 million remaining on its outstanding US$3,000 million base shelf prospectus filed in September 2007 that allows for the issue of US dollar debt securities in the United States until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

Share capital

As at December 31, 2008, there were 540,991,000 common shares outstanding and 30,962,000 stock options outstanding. As at March 3, 2009, the Company had 541,149,000 common shares outstanding and 30,285,000 stock options outstanding.

In March 2009, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.42 per common share for 2009. The increase represents a 5% increase from 2008. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

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. These commitments primarily relate to firm commitments for gathering, processing and transmission services; operating leases relating to offshore FPSOs, drilling rigs and office space; expenditures relating to asset retirement obligations; as well as long-term debt and interest payments. As at December 31, 2008, no entities were consolidated under the Canadian Institute of Chartered Accountants ("CICA") Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at December 31, 2008:

($ millions)	2009	2010	2011	2012	2013	Thereafter
Product transportation and pipeline	$ 219	$ 184	$ 159	$ 133	$ 124	$ 1,175
Offshore equipment operating lease	$ 175	$ 145	$ 144	$ 116	$ 117	$ 398
Offshore drilling	$ 251	$ 62	$ -	$ -	$ -	$ -
Asset retirement obligations (1)	$ 6	$ 7	$ 6	$ 6	$ 6	$ 4,443
Long-term debt (2)	$ 2,385	$ 400	$ 490	$ 429	$ 890	$ 6,707
Interest expense (3)	$ 610	$ 565	$ 543	$ 490	$ 428	$ 5,992
Office lease	$ 25	$ 29	$ 23	$ 2	$ 2	$ 1
Other	$ 321	$ 180	$ 17	$ 12	$ 8	$ 19

(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 2009 – 2013 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 $1,725 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 as at December 31, 2008.

Legal proceedings

The Company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. In addition, the Company is subject to certain contractor construction claims related to the Horizon Project. 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 judgements, 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 may 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, 2007.

For the impact of new accounting standards related to capital disclosures, inventory and financial instruments, refer to note 2 of the unaudited interim consolidated financial statements as at December 31, 2008.

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 commenced its IFRS conversion project in 2008 and has established a formal 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 Senior 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 – identification 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 phase. Significant differences were identified in accounting for Property, Plant & Equipment ("PP&E"), including exploration costs, depletion and depreciation, impairment testing, capitalized interest and asset retirement obligations. Other significant differences were noted in accounting for stock-based compensation, risk management activities, and income taxes. The Company is currently performing the necessary research to develop and document IFRS policies to address the major differences noted. At this time, the impact on the Company's future financial position and results of operations is not reasonably determinable. In addition, IFRS is expected to change prior to adoption in 2011, and the impact of these potential changes is not known. Included in the potential IFRS changes is an exposure draft issued in September 2008 by the IASB that proposes transition rules for oil and gas companies following full cost accounting. The proposed transition rule would allow 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. The Company intends to adopt the transition rule if it is approved.

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 2008, excluding mark-to-market gains (losses) on risk management activities and capitalized interest, 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	$ 112	$ 0.21	$ 84	$ 0.16
Including financial derivatives	$ 66	$ 0.12	$ 48	$ 0.09
Natural gas – AECO C$0.10/mcf (1)				
Excluding financial derivatives	$ 38	$ 0.07	$ 28	$ 0.05
Including financial derivatives	$ 38	$ 0.07	$ 28	$ 0.05
Volume changes				
Crude oil – 10,000 bbl/d	$ 87	$ 0.16	$ 38	$ 0.07
Natural gas – 10 mmcf/d	$ 18	$ 0.03	$ 7	$ 0.01
Foreign currency rate change				
$0.01 change in US$ (1)				
Including financial derivatives	$ 89 – 92	$ 0.17	$ 8 – 9	$ 0.02
Interest rate change – **1%**	$ 32	$ 0.06	$ 32	$ 0.06

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

OTHER OPERATING HIGHLIGHTS

NETBACK ANALYSIS

($/boe) [1]	Three Months Ended Dec 31 2008	Sep 30 2008	Dec 31 2007	Year Ended Dec 31 2008	Dec 31 2007
Sales price [2]	**$ 43.84**	$ 80.60	$ 49.23	**$ 68.62**	$ 49.05
Royalties	**5.37**	12.06	6.21	**9.78**	6.26
Production expense [3]	**12.05**	12.52	8.85	**11.79**	9.75
Netback	**26.42**	56.02	34.17	**47.05**	33.04
Midstream contribution [3]	**(0.23)**	(0.28)	(0.24)	**(0.25)**	(0.23)
Administration	**0.91**	0.91	0.76	**0.87**	0.93
Interest, net	**0.45**	0.49	0.92	**0.62**	1.24
Realized risk management (gain) loss	**(5.90)**	15.56	3.27	**8.99**	0.73
Realized foreign exchange (gain) loss	**(0.99)**	(0.80)	-	**(0.55)**	0.24
Taxes other than income tax – current	**0.53**	1.02	0.30	**1.18**	0.54
Current income tax – North America	**-**	0.09	0.56	**0.15**	0.43
Current income tax – North Sea	**0.22**	2.39	1.18	**1.64**	0.95
Current income tax – Offshore West Africa	**0.26**	0.87	0.50	**0.62**	0.33
Cash flow	**$ 31.17**	$ 35.77	$ 26.92	**$ 33.78**	$ 27.88

(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) Excluding intersegment elimination.

FINANCIAL STATEMENTS

Consolidated Balance Sheets

(millions of Canadian dollars, unaudited)	**Dec 31 2008**	Dec 31 2007
ASSETS		
Current assets		
Cash and cash equivalents	**$ 27**	$ 21
Accounts receivable and other	**1,514**	1,662
Future income tax	**-**	480
Current portion of other long-term assets (note 3)	**1,851**	18
	3,392	2,181
Property, plant and equipment (note 13)	**38,966**	33,902
Other long-term assets (note 3)	**292**	31
	$ 42,650	$ 36,114
LIABILITIES		
Current liabilities		
Accounts payable	**$ 383**	$ 379
Accrued liabilities	**1,802**	1,567
Future income tax	**585**	-
Current portion of long-term debt (note 4)	**420**	-
Current portion of other long-term liabilities (note 5)	**230**	1,617
	3,420	3,563
Long-term debt (note 4)	**12,596**	10,940
Other long-term liabilities (note 5)	**1,124**	1,561
Future income tax	**7,136**	6,729
	24,276	22,793
SHAREHOLDERS' EQUITY		
Share capital (note 7)	**2,768**	2,674
Retained earnings	**15,344**	10,575
Accumulated other comprehensive income (note 8)	**262**	72
	18,374	13,321
	$ 42,650	$ 36,114

Commitments (note 12)

Consolidated Statements of Earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended Dec 31 2008	Three Months Ended Dec 31 2007	Year Ended Dec 31 2008	Year Ended Dec 31 2007
Revenue	**$ 2,511**	$ 3,200	**$ 16,173**	$ 12,543
Less: royalties	**(268)**	(343)	**(2,017)**	(1,391)
Revenue, net of royalties	**2,243**	2,857	**14,156**	11,152
Expenses				
Production	**615**	491	**2,451**	2,184
Transportation and blending	**290**	467	**1,936**	1,570
Depletion, depreciation and amortization	**666**	719	**2,683**	2,863
Asset retirement obligation accretion (note 5)	**19**	17	**71**	70
Administration	**46**	42	**180**	208
Stock-based compensation (recovery) expense (note 5)	**(203)**	(16)	**(52)**	193
Interest, net	**23**	51	**128**	276
Risk management activities (note 11)	**(2,408)**	1,026	**(1,230)**	1,562
Foreign exchange loss (gain)	**562**	(47)	**718**	(471)
	(390)	2,750	**6,885**	8,455
Earnings before taxes	**2,633**	107	**7,271**	2,697
Taxes other than income tax	**22**	33	**178**	165
Current income tax expense (note 6)	**24**	123	**501**	380
Future income tax expense (recovery) (note 6)	**817**	(847)	**1,607**	(456)
Net earnings	**$ 1,770**	$ 798	**$ 4,985**	$ 2,608
Net earnings per common share (note 10)				
Basic and diluted	**$ 3.27**	$ 1.48	**$ 9.22**	$ 4.84

Consolidated Statements of Shareholders' Equity

(millions of Canadian dollars, unaudited)	Year Ended **Dec 31 2008**	Dec 31 2007
Share capital (note 7)		
Balance – beginning of year	**$ 2,674**	$ 2,562
Issued upon exercise of stock options	**18**	21
Previously recognized liability on stock options exercised for common shares	**76**	91
Balance – end of year	**2,768**	2,674
Retained earnings		
Balance – beginning of year	**10,575**	8,151
Net earnings	**4,985**	2,608
Dividends on common shares (note 7)	**(216)**	(184)
Balance – end of year	**15,344**	10,575
Accumulated other comprehensive income (note 8)		
Balance – beginning of year	**72**	146
Other comprehensive income (loss), net of taxes	**190**	(74)
Balance – end of year	**262**	72
Shareholders' equity	**$ 18,374**	$ 13,321

Consolidated Statements of Comprehensive Income

	Three Months Ended		Year Ended	
(millions of Canadian dollars, unaudited)	**Dec 31 2008**	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Net earnings	**$ 1,770**	$ 798	**$ 4,985**	$ 2,608
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income during the period, net of taxes of $1 million (2007 - $3 million) – three months ended; $1 million (2007 - $6 million) – year ended	**6**	32	**30**	38
Reclassification to net earnings, net of taxes of $nil (2007 - $21 million) – three months ended; $6 million (2007 - $45 million) – year ended	**(1)**	(45)	**(12)**	(96)
	5	(13)	**18**	(58)
Foreign currency translation adjustment				
Translation of net investment	**141**	-	**172**	(16)
Other comprehensive income (loss), net of taxes	**146**	(13)	**190**	(74)
Comprehensive income	**$ 1,916**	$ 785	**$ 5,175**	$ 2,534

Consolidated Statements of Cash Flows

(millions of Canadian dollars, unaudited)	Three Months Ended Dec 31 2008	Three Months Ended Dec 31 2007	Year Ended Dec 31 2008	Year Ended Dec 31 2007
Operating activities				
Net earnings	**$ 1,770**	$ 798	**$ 4,985**	$ 2,608
Non-cash items				
Depletion, depreciation and amortization	**666**	719	**2,683**	2,863
Asset retirement obligation accretion	**19**	17	**71**	70
Stock-based compensation (recovery) expense	**(203)**	(16)	**(52)**	193
Unrealized risk management (gain) loss	**(2,107)**	845	**(3,090)**	1,400
Unrealized foreign exchange loss (gain)	**613**	(47)	**832**	(524)
Deferred petroleum revenue tax (recovery) expense	**(5)**	17	**(67)**	44
Future income tax expense (recovery)	**817**	(847)	**1,607**	(456)
Other	**2**	31	**25**	38
Abandonment expenditures	**(15)**	(16)	**(38)**	(71)
Net change in non-cash working capital	**(205)**	(264)	**(189)**	(346)
	1,352	1,237	**6,767**	5,819
Financing activities				
Issue (repayment) of bank credit facilities, net	**286**	(128)	**(623)**	(1,925)
Issue of medium-term notes	**-**	398	**-**	273
Repayment of senior unsecured notes	**-**	-	**(31)**	(33)
Issue of US dollar debt securities	**-**	-	**1,215**	2,553
Issue of common shares on exercise of stock options	**1**	2	**18**	21
Dividends on common shares	**(54)**	(46)	**(208)**	(178)
Net change in non-cash working capital	**48**	2	**46**	8
	281	228	**417**	719
Investing activities				
Expenditures on property, plant and equipment	**(1,817)**	(1,603)	**(7,433)**	(6,464)
Net proceeds on sale of property, plant and equipment	**5**	105	**20**	110
Net expenditures on property, plant and equipment	**(1,812)**	(1,498)	**(7,413)**	(6,354)
Net change in non-cash working capital	**192**	33	**235**	(186)
	(1,620)	(1,465)	**(7,178)**	(6,540)
Increase (decrease) in cash and cash equivalents	**13**	-	**6**	(2)
Cash and cash equivalents – beginning of period	**14**	21	**21**	23
Cash and cash equivalents – end of period	**$ 27**	$ 21	**$ 27**	$ 21
Interest paid	**$ 112**	$ 153	**$ 574**	$ 556
Taxes paid				
Taxes other than income tax	**$ 83**	$ 13	**$ 300**	$ 116
Current income tax	**$ 135**	$ 145	**$ 258**	$ 302

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, 2007, 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, 2007.

Comparative Figures

Certain prior period figures have been reclassified to conform to the presentation adopted in 2008.

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2008 the Company adopted the following accounting and disclosure standards issued by the Canadian Institute of Chartered Accountants ("CICA"):

- **Capital Disclosures** – Section 1535 – "Capital Disclosures" requires entities to disclose their objectives, policies and processes for managing capital, as well as quantitative data about capital. The standard also requires the disclosure of any externally imposed capital requirements and compliance with those requirements. The standard does not define capital. This standard affected disclosure only and did not impact the Company's accounting for capital (note 9).
- **Inventories** – Section 3031 – "Inventories" replaces Section 3030 – "Inventories" and establishes new standards for the measurement of cost of inventories and expands disclosure requirements for inventories. Adoption of this standard did not have a material impact on the Company's financial statements.
- **Financial Instruments** – Section 3862 – "Financial Instruments – Disclosure" and Section 3863 – "Financial Instruments – Presentation" replace Section 3861 – "Financial Instruments – Disclosure and Presentation". Section 3862 enhances disclosure requirements concerning risks and requires quantitative and qualitative disclosures about exposures to risks arising from financial instruments. Section 3863 carries forward the presentation requirements from Section 3861 unchanged. These standards affected disclosures only and did not impact the Company's accounting for financial instruments (note 11).

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 is currently assessing which accounting policies will be affected by the change to IFRS and the potential impact of these changes on its financial position and results of operations.

3. OTHER LONG-TERM ASSETS

	Dec 31 2008	Dec 31 2007
Risk management (note 11)	**$ 2,119**	$ -
Other	**24**	49
	2,143	49
Less: current portion	**1,851**	18
	$ 292	$ 31

4. LONG–TERM DEBT

	Dec 31 2008	Dec 31 2007
Canadian dollar denominated debt		
Bank credit facilities (bankers' acceptances)	**$ 4,073**	$ 4,696
Medium-term notes	**1,200**	1,200
	5,273	5,896
US dollar denominated debt		
Senior unsecured notes (2008 - US$31 million; 2007 - US$62 million)	**38**	61
US dollar debt securities (2008 - US$6,300 million; 2007 - US$5,108 million)	**7,715**	5,048
Less – original issue discount on senior unsecured notes and US dollar debt securities (1)	**(23)**	(23)
	7,730	5,086
Fair value impact of interest rate swaps on US dollar debt securities (2)	**68**	9
	7,798	5,095
Long-term debt before transaction costs	**13,071**	10,991
Less: transaction costs (1) (3)	**(55)**	(51)
	13,016	10,940
Less: current portion	**420**	-
	$ 12,596	$ 10,940

(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 $68 million (2007 – $9 million) to reflect the fair value impact of hedge accounting.*

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

Bank credit facilities

As at December 31, 2008, the Company had in place unsecured bank credit facilities of $6,232 million, comprised of:

- a $125 million demand credit facility;
- a non-revolving syndicated credit facility of $2,350 million maturing October 2009;
- 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.

In conjunction with the closing of the acquisition of ACC in November 2006, the Company executed a $3,850 million, non-revolving syndicated credit facility maturing October 2009. In March 2007, $1,500 million was repaid, reducing the facility to $2,350 million. During 2009, the Company plans to fully retire this facility from its existing uncommitted borrowing capacity under its other long-term bank credit facilities of $2,050 million, supported by cash flow from operating activities, including the commodity risk management activities. In accordance with these plans, and repayments of $420 million made subsequent to December 31, 2008 on this facility, $420 million has been classified as current.

The weighted average interest rate of the bank credit facilities outstanding at December 31, 2008, was 2.2% (December 31, 2007 – 5.2%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $372 million, including $300 million related to the Horizon Oil Sands Project ("Horizon Project"), were outstanding at December 31, 2008.

Medium-term notes

The Company has $2,600 million remaining on its outstanding $3,000 million base shelf prospectus filed in September 2007 that allows for the issue of medium-term notes in Canada until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

Senior unsecured notes

During the second quarter of 2008, US$31 million of the senior unsecured notes were repaid.

US dollar debt securities

During the fourth quarter of 2008, the Company terminated the interest rate swaps that had been designated as a fair value hedge of US$350 million of 5.45% unsecured notes due October 2012. Accordingly, the Company ceased revaluing the related debt from the date of termination of the interest rate swaps for subsequent changes in fair value. The fair value adjustment of $20 million at the date of termination is being amortized to interest expense over the remaining term of the debt.

During the third quarter of 2008, US$8 million of US dollar debt securities were repaid.

In January 2008, the Company issued US$1,200 million of unsecured notes under a US base shelf prospectus, comprised of US$400 million of 5.15% unsecured notes due February 2013, US$400 million of 5.90% unsecured notes due February 2018, and US$400 million of 6.75% unsecured notes due February 2039. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these securities, the Company has US$1,800 million remaining on its outstanding US$3,000 million base shelf prospectus filed in September 2007 that allows for the issue of US dollar debt securities in the United States until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

5. OTHER LONG–TERM LIABILITIES

	Dec 31 2008	Dec 31 2007
Asset retirement obligations	**$ 1,064**	$ 1,074
Stock-based compensation	**171**	529
Risk management (note 11)	**-**	1,474
Other	**119**	101
	1,354	3,178
Less: current portion	**230**	1,617
	$ 1,124	$ 1,561

Asset retirement obligations

At December 31, 2008, the Company's total estimated undiscounted costs to settle its asset retirement obligations were approximately $4,474 million (December 31, 2007 – $4,426 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 6.7% (December 31, 2007 – 6.6%). A reconciliation of the discounted asset retirement obligations is as follows:

	Year Ended Dec 31, 2008	Year Ended Dec 31, 2007
Balance – beginning of year	**$ 1,074**	$ 1,166
Liabilities incurred	**18**	21
Liabilities acquired (disposed)	**3**	(65)
Liabilities settled	**(38)**	(71)
Asset retirement obligation accretion	**71**	70
Revision of estimates	**(156)**	35
Foreign exchange	**92**	(82)
Balance – end of year	**$ 1,064**	$ 1,074

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, 2008	Year Ended Dec 31, 2007
Balance – beginning of year	**$ 529**	$ 744
Stock-based compensation	**(52)**	193
Payments for options surrendered	**(207)**	(375)
Transferred to common shares	**(76)**	(91)
Capitalized to Horizon Project	**(23)**	58
Balance – end of year	**171**	529
Less: current portion	**159**	390
	$ 12	$ 139

6. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Year Ended	
	Dec 31 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Current income tax – North America	**$ -**	$ 31	**$ 33**	$ 96
Current income tax – North Sea	**12**	65	**340**	210
Current income tax – Offshore West Africa	**12**	27	**128**	74
Current income tax expense	**24**	123	**501**	380
Future income tax expense (recovery)	**817**	(847)	**1,607**	(456)
Income tax expense (recovery)	**$ 841**	$ (724)	**$ 2,108**	$ (76)

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, North America and North Sea current income taxes will vary depending on available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

During the first quarter of 2008, substantively enacted or enacted income tax rate changes resulted in a reduction of future income tax liabilities of approximately $19 million in British Columbia and $22 million in Côte d'Ivoire, Offshore West Africa.

During the second quarter of 2007, the Canadian Federal Government enacted income tax rate changes, resulting in a reduction of future income tax liabilities of approximately $71 million.

During the fourth quarter of 2007, the Canadian Federal Government substantively enacted or enacted income tax rate and other legislative changes, resulting in a reduction of future income tax liabilities of approximately $793 million.

7. SHARE CAPITAL

Issued Common shares	Year Ended Dec 31, 2008 Number of shares (thousands)	Amount
Balance – beginning of year	**539,729**	**$ 2,674**
Issued upon exercise of stock options	**1,262**	**18**
Previously recognized liability on stock options exercised for common shares	**-**	**76**
Balance – end of year	**540,991**	**$ 2,768**

Dividend policy

In March 2009, the Board of Directors set the regular quarterly dividend at $0.105 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 February 2008, the Board of Directors set the regular quarterly dividend at $0.10 per common share (2007 – $0.085 per common share).

Stock options

	Year Ended Dec 31, 2008 Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of year	**30,659**	**$ 47.23**
Granted	**7,705**	**$ 53.38**
Surrendered for cash settlement	**(3,702)**	**$ 25.60**
Exercised for common shares	**(1,262)**	**$ 14.61**
Forfeited	**(2,438)**	**$ 56.56**
Outstanding – end of year	**30,962**	**$ 51.94**
Exercisable – end of year	**8,809**	**$ 44.58**

8. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Dec 31 2008	Dec 31 2007
Derivative financial instruments designated as cash flow hedges	**$ 119**	$ 101
Foreign currency translation adjustment	**143**	(29)
	$ 262	$ 72

During 2008, the Company determined that its operations in Offshore West Africa were now operationally and financially independent and the current rate method of translation was adopted for translation of the financial statements of its Offshore West African subsidiaries. This change has been applied prospectively. The impact of this change was to increase assets by $32 million, decrease liabilities by $4 million and increase accumulated other comprehensive income by $36 million.

9. CAPITAL DISCLOSURES

As required by Canadian GAAP, effective January 1, 2008, the Company must provide certain disclosures regarding its objectives, policies and processes for managing capital, as well as provide certain quantitative data about capital. As the Company does not have any externally imposed regulatory capital requirements, for the purposes of this disclosure, 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 near the midpoint of the target range at 41% including the impact of capital spending on the Horizon Project.

Readers are cautioned that as the debt to book capitalization ratio has no defined meaning under GAAP, this financial measure may not be comparable to similar measures provided by other reporting entities. 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 2008	Dec 31 2007
Long-term debt (1)	**$ 13,016**	$ 10,940
Total shareholders' equity	**$ 18,374**	$ 13,321
Debt to book capitalization	**41%**	45%

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

10. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Year Ended	
	Dec 31 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Weighted average common shares outstanding (thousands) – basic and diluted	**540,914**	539,652	**540,647**	539,336
Net earnings – basic and diluted	**$ 1,770**	$ 798	**$ 4,985**	$ 2,608
Net earnings per common share – basic and diluted	**$ 3.27**	$ 1.48	**$ 9.22**	$ 4.84

11. FINANCIAL INSTRUMENTS

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

	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**	**-**	**-**
Risk management	**-**	**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 the long-term debt.

	Dec 31, 2007		
Asset (liability)	Loans and receivables at amortized cost	Held for trading at fair value	Other financial liabilities at amortized cost
Cash and cash equivalents	$ -	$ 21	$ -
Accounts receivable	1,143	-	-
Accounts payable	-	-	(379)
Accrued liabilities	-	-	(1,567)
Risk management	-	(1,474)	-
Other long-term liabilities	-	-	(86)
Long-term debt	-	-	(10,940)
	$ 1,143	$ (1,453)	$ (12,972)

The carrying value of the Company's financial instruments approximates their fair value, except for fixed-rate long-term debt as noted below:

	Dec 31, 2008		Dec 31, 2007	
	Carrying value	**Fair value**	Carrying value	Fair value
Fixed rate long-term debt [(1)]	**$ 8,943**	**$ 7,649**	$ 6,244	$ 6,259

(1) 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 $68 million (2007 – $9 million) to reflect the fair value impact of hedge accounting.

Risk management

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

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company has relied primarily 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, 2008		Year Ended Dec 31, 2007
Asset (liability)		**Risk management mark-to-market**		Risk management mark-to-market
Balance – beginning of year	**$**	**(1,474)**	$	128
Retained earnings effect of adoption of financial instrument standards		**-**		14
Net cost of outstanding put options		**297**		58
Net change in fair value of outstanding derivative financial instruments attributable to:				
- Risk management activities		**3,090**		(1,400)
- Interest expense		**60**		9
- Foreign exchange		**449**		(350)
- Other comprehensive income		**18**		125
- Settlement of interest rate swaps		**(20)**		-
		2,420		(1,416)
Add: put premium financing obligations (1)		**(301)**		(58)
Balance – end of year		**2,119**		(1,474)
Less: current portion		**1,851**		(1,227)
	$	**268**	$	(247)

(1) The Company has negotiated payment of put option premiums with various counterparties at the time of actual settlement of the respective options. These obligations have been 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 2008		Dec 31 2007		**Dec 31 2008**		Dec 31 2007
Net realized risk management (gain) loss	**$**	**(301)**	$	181	**$**	**1,860**	$	162
Net unrealized risk management (gain) loss		**(2,107)**		845		**(3,090)**		1,400
	$	**(2,408)**	$	1,026	**$**	**(1,230)**	$	1,562

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, 2008, 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 2009	–	Dec 2009	25,000 bbl/d	US$70.00	–	US$111.56	WTI
	Apr 2009	–	Jun 2009	4,000 bbl/d	US$70.00	–	US$90.00	WTI
Crude oil puts	Jan 2009	–	Dec 2009	92,000 bbl/d			US$100.00	WTI

At December 31, 2008, the net cost of outstanding put options and their respective periods of settlement was as follows:

	Q1 2009	Q2 2009	Q3 2009	Q4 2009
Cost ($ millions)	US$60	US$60	US$61	US$61

	Remaining term			Volume	Weighted average price			Index
Natural gas								
Natural gas price collars (1)	Jan 2009	–	Mar 2009	500,000 GJ/d	C$6.00	–	C$8.63	AECO

(1) Subsequent to December 31, 2008, the Company entered into 220,000 GJ/d of C$6.00 – C$8.00 natural gas AECO collars for the period January to December 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, 2008.

In addition to the derivative financial instruments noted above, subsequent to December 31, 2008, the Company entered into natural gas physical sales contracts for 400,000 GJ/d at an average fixed price of C$5.29 per GJ at AECO for the period April to December 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, 2008, 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 2009	–	Dec 2014	US$350	4.90%	LIBOR (1) + 0.38%

(1) London Interbank Offered Rate

All interest rate related derivative financial instruments designated as hedges at December 31, 2008 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, 2008, 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 2009	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2009	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2009	–	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments designated as hedges at December 31, 2008 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, the Company periodically utilizes foreign currency forward contracts to manage certain foreign currency cash management needs. At December 31, 2008, the Company had US$408 million of these contracts outstanding, with terms of approximately 30 days or less.

Financial instrument sensitivities

As required by Canadian GAAP, the Company must provide certain quantitative sensitivities related to its financial instruments, which are prepared on a different basis than those sensitivities currently disclosed in the Company's other continuous disclosure documents. 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, 2008 resulting from changes in the specified variable, with all other variables held constant. These sensitivities 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	$ (32)	$ -
Decrease WTI US$1.00/bbl	$ 32	$ -
Increase AECO C$0.10/mcf	$ (1)	$ -
Decrease AECO C$0.10/mcf	$ 1	$ -
Interest rate risk		
Increase interest rate 1%	$ (32)	$ (27)
Decrease interest rate 1%	$ 32	$ 33
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$ (35)	$ -
Decrease exchange rate by US$0.01	$ 35	$ -

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, 2008, substantially all of the Company's accounts receivables were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions and other entities. At December 31, 2008, the Company had net risk management assets of $2,119 million with specific counterparties related to derivative financial instruments (December 31, 2007 – $20 million). The Company believes that its counterparties currently have the financial capacity to settle outstanding obligations in the normal course of business.

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	$ 383	$ -	$ -	$ -
Accrued liabilities	$ 1,802	$ -	$ -	$ -
Other long-term liabilities	$ 86	$ 18	$ 1	$ -
Long-term debt (1)	$ 2,385	$ 400	$ 1,809	$ 6,707

(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 $1,725 million of revolving bank credit facilities due to the extendable nature of the facilities.

12. COMMITMENTS

As at December 31, 2008, the Company had committed to certain payments as follows:

	2009	2010	2011	2012	2013	Thereafter
Product transportation and pipeline	$ 219	$ 184	$ 159	$ 133	$ 124	$ 1,175
Offshore equipment operating leases	$ 175	$ 145	$ 144	$ 116	$ 117	$ 398
Offshore drilling	$ 251	$ 62	$ -	$ -	$ -	$ -
Asset retirement obligations (1)	$ 6	$ 7	$ 6	$ 6	$ 6	$ 4,443
Office leases	$ 25	$ 29	$ 23	$ 2	$ 2	$ 1
Other	$ 321	$ 180	$ 17	$ 12	$ 8	$ 19

(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 2009 – 2013 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

13. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America Three Months Ended Dec 31		North America Year Ended Dec 31		North Sea Three Months Ended Dec 31		North Sea Year Ended Dec 31		Offshore West Africa Three Months Ended Dec 31		Offshore West Africa Year Ended Dec 31	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007
Segmented revenue	**2,116**	2,571	**13,496**	10,149	**262**	367	**1,769**	1,597	**186**	260	**944**	776
Less: royalties	**(259)**	(317)	**(1,876)**	(1,318)	**(1)**	(1)	**(4)**	(3)	**(14)**	(25)	**(143)**	(70)
Segmented revenue, net of royalties	**1,857**	2,254	**11,620**	8,831	**261**	366	**1,765**	1,594	**172**	235	**801**	706
Segmented expenses												
Production	**457**	377	**1,881**	1,642	**117**	79	**457**	432	**41**	31	**102**	94
Transportation and blending	**301**	473	**1,975**	1,595	**2**	4	**10**	16	**-**	1	**1**	1
Depletion, depreciation and amortization	**552**	602	**2,236**	2,350	**84**	69	**317**	340	**38**	46	**132**	165
Asset retirement obligation accretion	**10**	10	**42**	38	**8**	7	**27**	30	**1**	-	**2**	2
Realized risk management activities	**(301)**	182	**1,861**	129	**-**	(1)	**(1)**	33	**-**	-	**-**	-
Total segmented expenses	**1,019**	1,644	**7,995**	5,754	**211**	158	**810**	851	**80**	78	**237**	262
Segmented earnings before the following	**838**	610	**3,625**	3,077	**50**	208	**955**	743	**92**	157	**564**	444
Non-segmented expenses												
Administration												
Stock-based compensation (recovery) expense												
Interest, net												
Unrealized risk management activities												
Foreign exchange loss (gain)												
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)	Midstream				Intersegment 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	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007
Segmented revenue	**17**	19	**77**	74	**(70)**	(17)	**(113)**	(53)	**2,511**	3,200	**16,173**	12,543
Less: royalties	**-**	-	**-**	-	**6**	-	**6**	-	**(268)**	(343)	**(2,017)**	(1,391)
Segmented revenue, net of royalties	**17**	19	**77**	74	**(64)**	(17)	**(107)**	(53)	**2,243**	2,857	**14,156**	11,152
Segmented expenses												
Production	**6**	6	**25**	22	**(6)**	(2)	**(14)**	(6)	**615**	491	**2,451**	2,184
Transportation and blending	**-**	-	**-**	-	**(13)**	(11)	**(50)**	(42)	**290**	467	**1,936**	1,570
Depletion, depreciation and amortization	**2**	2	**8**	8	**(10)**	-	**(10)**	-	**666**	719	**2,683**	2,863
Asset retirement obligation accretion	**-**	-	**-**	-	**-**	-	**-**	-	**19**	17	**71**	70
Realized risk management activities	**-**	-	**-**	-	**-**	-	**-**	-	**(301)**	181	**1,860**	162
Total segmented expenses	**8**	8	**33**	30	**(29)**	(13)	**(74)**	(48)	**1,289**	1,875	**9,001**	6,849
Segmented earnings before the following	**9**	11	**44**	44	**(35)**	(4)	**(33)**	(5)	**954**	982	**5,155**	4,303
Non-segmented expenses												
Administration									**46**	42	**180**	208
Stock-based compensation (recovery) expense									**(203)**	(16)	**(52)**	193
Interest, net									**23**	51	**128**	276
Unrealized risk management activities									**(2,107)**	845	**(3,090)**	1,400
Foreign exchange loss (gain)									**562**	(47)	**718**	(471)
Total non-segmented expenses									**(1,679)**	875	**(2,116)**	1,606
Earnings before taxes									**2,633**	107	**7,271**	2,697
Taxes other than income tax									**22**	33	**178**	165
Current income tax expense									**24**	123	**501**	380
Future income tax expense (recovery)									**817**	(847)	**1,607**	(456)
Net earnings									**1,770**	798	**4,985**	2,608

Net additions to property, plant and equipment

	Year Ended					
	Dec 31, 2008			Dec 31, 2007		
	Net Expenditures	**Non Cash/Fair Value Changes (1)**	**Capitalized Costs**	Net Expenditures	Non Cash/Fair Value Changes (1)	Capitalized Costs
North America	**$ 2,344**	**$ (7)**	**$ 2,337**	$ 2,428	$ 52	$ 2,480
North Sea	**319**	**(127)**	**192**	439	(77)	362
Offshore West Africa	**811**	**6**	**817**	159	(11)	148
Other	**1**	**-**	**1**	1	-	1
Horizon Project (2)	**3,912**	**10**	**3,922**	3,301	-	3,301
Midstream	**9**	**-**	**9**	6	-	6
Head office	**17**	**-**	**17**	20	-	20
	$ 7,413	**$ (118)**	**$ 7,295**	$ 6,354	$ (36)	$ 6,318

(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 the Horizon Project also include capitalized interest, stock-based compensation, and the impact of intersegment eliminations.

	Property, plant and equipment		Total assets	
	Dec 31 2008	Dec 31 2007	**Dec 31 2008**	Dec 31 2007
Segmented assets				
North America	**$ 22,151**	$ 22,033	**$ 24,875**	$ 23,617
North Sea	**2,048**	1,728	**2,638**	1,957
Offshore West Africa	**1,894**	1,188	**2,013**	1,354
Other	**26**	25	**64**	41
Horizon Project	**12,573**	8,651	**12,677**	8,740
Midstream	**206**	205	**315**	333
Head office	**68**	72	**68**	72
	$ 38,966	$ 33,902	**$ 42,650**	$ 36,114

Capitalized interest

The Company capitalizes construction period interest based on Horizon Project costs incurred and the Company's cost of borrowing. Interest capitalization on a particular development phase ceases once construction is substantially complete and this phase of the Horizon Project is available for its intended use. For the year ended December 31, 2008, pre-tax interest of $481 million was capitalized to the Horizon Project (December 31, 2007 – $356 million).

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

Under Canadian full cost accounting rules, costs capitalized in each country cost centre are limited to an amount equal to the undiscounted, future net revenues from proved reserves using estimated future prices and costs, plus the carrying amount of unproved properties and major development projects (the “ceiling test”). No ceiling test impairment was recognized under Canadian GAAP at December 31, 2008, as future net revenues exceeded the capitalized costs.

Under generally accepted accounting principles in the United States (“US GAAP”), the Company prepared a ceiling test calculation as at December 31, 2008, 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 prices and costs as at the balance sheet date (“constant dollar pricing”) 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 a ceiling test impairment, reducing property, plant and equipment by $8,665 million in 2008.

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 September 2007. 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, 2008:

Interest coverage (times)	
Net earnings (1)	11.9x
Cash flow from operations (2)	12.5x

(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 5, 2009. The North American conference call number is **1-866-226-1793** and the outside North American conference call number is **001-416-641-6128**. 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 12, 2009. 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 3279962.

WEBCAST

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

The webcast is also being distributed over PrecisionIR's Investor Distribution Network to both institutional and individual investors. Investors can listen to the call through www.vcall.com or by visiting any of the investor sites in PrecisionIR's Individual Investor Network.

2009 FIRST QUARTER RESULTS

2009 first quarter results are scheduled for release on Thursday, May 7, 2009. A conference call will be held on that day at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time.

For further information, please contact:

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