Canadian Natural

News Release

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES
2007 FOURTH QUARTER AND YEAR END RESULTS
CALGARY, ALBERTA – FEBRUARY 28, 2008 – FOR IMMEDIATE RELEASE

Commenting on the Fourth Quarter of 2007 and year end results, Canadian Natural Chairman, Allan Markin stated, “Another solid year of value creation was achieved in 2007 reflecting a strong, well-balanced asset base. Our North American and International conventional assets provide balance between natural gas and crude oil, a solid foundation for future growth and generate significant free cash flow. The Horizon Project, our world class oil sands project, is targeted to produce first oil in Q3/08, creating tremendous value for shareholders. We continue to have a direct and indirect, positive impact on the communities in which we operate and remain committed to working together with stakeholders in these communities. This is even more important in today’s challenging environment of cost pressures, commodity price volatility and ever changing governmental regulation.”

John Langille, Vice Chairman, stated, “Our balance sheet ended the year at 45% debt to book capitalization compared with 51% one year ago and we will continue to strengthen our balance sheet during 2008 and into 2009, creating additional flexibility to take advantage of opportunities as they arise. Based upon strip pricing and production guidance, we estimate that 2008 cash flow may approach $6.0 billion, resulting in a targeted 2008 year end debt to book capitalization of approximately 40%, even after the announced upward revisions to our 2008 capital cost guidance for the Horizon Project. We have the financial strength and the ability to execute on the growth opportunities which we have in the near, medium and long-term.”

Steve Laut, President and Chief Operating Officer of Canadian Natural commented, “In 2007 we effectively executed on our program and delivered results at or exceeding our budget at reasonable costs. Our proved finding and on-stream costs of $14.28 per barrel of oil equivalent, represents a 12% decrease from 2006. Looking forward, 2008 is the year of execution for Canadian Natural as we deliver four major projects. First, Primrose East, the next stage in the development of our expansive thermal in-situ assets, will begin steaming in late 2008 and is targeted to add approximately 40,000 bbl/d of capacity in 2009. Secondly, the Olowi project in Offshore Gabon is targeted to start producing first oil in late 2008 and will reach peak production of 20,000 bbl/d. Thirdly, the deep water drilling rig for our Baobab project in Offshore Côte d’Ivoire is expected to arrive in mid-year 2008. It is anticipated that the resulting repairs to at least three of the five shut-in Baobab wells, will add up to 10,000 bbl/d of capacity by mid 2009. Lastly, we are targeting to have first oil at the Horizon Project, our 110,000 bbl/d oil sands mining project in Q3/08. Again, 2008 is the year of execution and 2009 is the year of reward.”

HIGHLIGHTS

	Quarterly Results			Year End Results	
($ millions, except as noted)	**Q4/07**	Q3/07	Q4/06	**2007**	2006
Net earnings	**$ 798**	$ 700	$ 313	**$ 2,608**	$ 2,524
per common share, basic and diluted	**$ 1.48**	$ 1.30	$ 0.58	**$ 4.84**	$ 4.70
Adjusted net earnings from operations (1)	**$ 546**	$ 644	$ 412	**$ 2,406**	$ 1,664
per common share, basic and diluted	**$ 1.02**	$ 1.19	$ 0.77	**$ 4.46**	$ 3.10
Cash flow from operations (2)	**$ 1,486**	$ 1,577	$ 1,293	**$ 6,198**	$ 4,932
per common share, basic and diluted	**$ 2.75**	$ 2.92	$ 2.41	**$ 11.49**	$ 9.18
Capital expenditures, net of dispositions	**$ 1,514**	$ 1,442	$ 6,497	**$ 6,425**	$ 12,025
Daily production, before royalties					
Natural gas (mmcf/d)	**1,589**	1,647	1,620	**1,668**	1,492
Crude oil and NGLs (bbl/d)	**337,240**	333,062	343,705	**331,232**	331,998
Equivalent production (boe/d)	**601,908**	607,484	613,764	**609,206**	580,724

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

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

Annual

- Total natural gas production in 2007 averaged 1,668 mmcf/d, an increase of 12% from 2006, primarily due to a full year of production from the Anadarko Canada Corporation acquisition in November of 2006. As anticipated, 2007 entry to exit natural gas production volumes declined but the assets continued to perform well.
- Total crude oil and NGLs production in 2007 averaged 331,232 bbl/d, a slight decrease from 2006. North America grew 5%, offset by a decrease in production from the International operations.
- Cash flow from operations increased 26% to $6.2 billion in 2007 from $4.9 billion in 2006, and net earnings increased 3% in 2007 to $2.6 billion from $2.5 billion in 2006. Cash flow was primarily impacted due to increased sales volumes, higher realized pricing, and lower realized risk management losses, offset by increased production expense, higher interest costs, higher current taxes, and the impact of the stronger Canadian dollar relative to the US dollar.

Fourth Quarter

- Natural gas production for Q4/07 averaged 1,589 mmcf/d, down 2% from 1,620 mmcf/d for Q4/06 and down 4% from 1,647 mmcf/d for Q3/07. Volumes in Q4/07 reflected the continued reallocation of capital towards higher return projects in crude oil.
- Total crude oil and NGLs production for Q4/07 was 337,240 bbl/d. Q4/07 production was 2% lower than Q4/06 volumes of 343,705 bbl/d, and increased from Q3/07 volumes of 333,062 bbl/d. Volumes in Q4/07 reflect the transition from steam cycles to production cycles for a number of thermal wells and continued conversion of production wells to polymer injection wells at Pelican Lake.
- Quarterly cash flow from operations was $1.5 billion, an increase of 15% from Q4/06 and a decrease of 6% from Q3/07. The increase from Q4/06 primarily reflected higher crude oil realizations and the impact of higher sales volumes. The decrease from Q3/07 represented lower natural gas sales volumes in Q4/07 and higher risk management losses. Cash flow in Q4/07 continued to be negatively impacted by the strengthening of the Canadian

dollar compared to the US dollar. The average exchange rate for Q4/07 was US$0.9810 per C$1.00 compared with US$1.0455 per C$1.00 for Q3/07 and US$1.1388 per C$1.00 for Q4/06.

- Q4/07 quarterly net earnings were $798 million, a 155% increase from Q4/06 and a 14% increase from Q3/07. Quarterly adjusted net earnings from operations for Q4/07 were $546 million, a 33% increase from Q4/06 and a decrease of 15% from Q3/07 results.
- Completed the Q4/07 North America drilling program targeting 172 net crude oil wells and 92 net natural gas wells with a 94% 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 12 million net acres - a key asset for continued value growth.
- Continued production improvements at the Pelican Lake Field were realized from new drilling activity and the expansion of the enhanced crude oil recovery program. Pelican Lake crude oil production averaged approximately 36,000 bbl/d during the quarter, up 24% or approximately 7,000 bbl/d from Q4/06.
- The Primrose East expansion, which is targeted to add 40,000 bbl/d of capacity, made significant progress and is targeted for first steaming in Q4/08 and production in 2009.
- Secured a deep water drilling rig for the Baobab Field. The equipment is targeted to be mobilized in mid-year 2008, enabling work to begin on the restoration of shut-in production. It is forecasted that a minimum 3 of the 5 shut-in Baobab wells should come back on stream over the course of 2008 and 2009.
- The Olowi project in Offshore Gabon continues on track. Drilling is targeted to commence in Q2/08 and first crude oil is targeted for late 2008.
- Work progress on the Horizon Oil Sands Project ("Horizon Project") exited Q4/07 at 90% complete and remains on track for first oil targeted for Q3/08.
- Independent qualified reserve evaluators evaluated 100% of the Company's conventional crude oil and natural gas reserves under constant prices and costs as at December 31, 2007:
    - Total net proved reserves from conventional operations at the end of 2007 amounted to 1.4 billion barrels of crude oil and NGLs and 3.7 trillion cubic feet of natural gas. Total net proved conventional reserves increased modestly from 2006 to 2007.
    - Net proved reserve additions from conventional operations equaled 110% of 2007 net production, at a finding and on-stream cost of $14.28 per barrel of oil equivalent. The Company's three-year average proved finding and on-stream costs were $15.07 per barrel of oil equivalent.
    - Total net proved and probable reserves from conventional operations at the end of 2007 amounted to 2.1 billion barrels of crude oil and NGLs and 4.8 trillion cubic feet of natural gas. Total proved and probable net conventional reserves remained relatively unchanged from the prior year.
    - Net proved and probable reserve additions from conventional operations equaled 87% of 2007 net production, at a finding and on-stream cost of $18.02 per barrel of oil equivalent. The Company's three-year average net proved and probable finding and on-stream costs were $11.03 per barrel of oil equivalent. As anticipated, the significantly reduced drilling program in 2007 resulted in less proved and probable reserves being booked.
    - Using net proved finding and on-stream costs, the Company achieved an overall recycle ratio of 2.3x during 2007.
- Independent qualified reserve evaluators 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, 2007, which resulted in 2.4 billion barrels of gross lease proved bitumen reserves and 3.5 billion barrels of gross lease proved and probable bitumen reserves. The gross lease proved synthetic crude oil reserves increased by 90 million barrels in 2007 to 2.0 billion barrels. The gross lease proved and probable synthetic crude oil reserves were 3.0 billion barrels.

- On October 25, 2007 the Province of Alberta issued the framework of its proposed changes to the Alberta crude oil and natural gas royalty regime, effective January 1, 2009. The Company is currently awaiting finalization of the royalty implementation regulations, however it expects that its 2009 and future Alberta royalty payments will increase as a result of the proposed royalty changes and that its level of activity in Alberta in aggregate will be reduced from what it otherwise would have been in the absence of such royalty changes.
- In December 2007, the Company issued $400 million of unsecured notes under a Canadian base shelf prospectus maturing December 2010, bearing interest at 5.50%. 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 which have been sold to investors in the United States. Net proceeds from the issue of these notes were used to repay bankers' acceptances.
- For the eighth consecutive year the Company's dividend was increased. The 2008 quarterly cash dividend on common shares has been increased to C$0.10 per common share, payable April 1, 2008, an 18% increase over the 2007 quarterly dividend.

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 and 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, 2007 (thousands of net acres)	Drilling activity year ended Dec 31, 2007 (net wells) [1]
Canadian conventional		
Northeast British Columbia	**2,401**	**61**
Northwest Alberta	**1,489**	**126**
Northern Plains	**6,626**	**636**
Southern Plains	**925**	**169**
Southeast Saskatchewan	**121**	**28**
In-situ Oil Sands	**483**	**192**
	12,045	**1,212**
Horizon Oil Sands Project	**115**	**98**
United Kingdom North Sea	**287**	**7**
Offshore West Africa	**206**	**5**
	12,653	**1,322**

(1) Drilling activity includes stratigraphic test and service wells

Drilling activity (number of wells)

	Year Ended Dec 31			
	2007		2006	
	Gross	**Net**	Gross	Net
Crude oil	**655**	**592**	666	603
Natural gas	**478**	**383**	855	641
Dry	**107**	**93**	133	119
Subtotal	**1,240**	**1,068**	1,654	1,363
Stratigraphic test / service wells	**256**	**254**	376	375
Total	**1,496**	**1,322**	2,030	1,738
Success rate (excluding stratigraphic test / service wells)		**91%**		91%

North America Conventional

North America natural gas

	Quarterly Results			Year End Results	
	Q4/07	Q3/07	Q4/06	**2007**	2006
Natural gas production (mmcf/d)	**1,562**	1,622	1,594	**1,643**	1,468
Net wells targeting natural gas	**92**	106	74	**450**	732
Net successful wells drilled	**80**	96	60	**383**	641
Success rate	**87%**	91%	81%	**85%**	88%

- Natural gas annual average production increased 12% in 2007 as compared to 2006 primarily due to a full year of production from the Anadarko Canada Corporation acquisition in November of 2006.
- Natural gas drilling in 2007 was down 39% from 2006. This reflects the strategic decision to reduce the natural gas development due to a high cost environment and the reallocation of capital to stronger return crude oil projects.
- As anticipated, Q4/07 North America natural gas production decreased slightly by 2% from Q4/06 and decreased by 4% from Q3/07. The decrease reflected the Company's strategic decision to scale back the 2007 drilling program due to reallocating capital to higher return crude oil projects and natural decline rates.
- Canadian Natural targeted 92 net natural gas wells in Q4/07 including 7 wells in the Northern Plains region, 20 wells in the Northwest Alberta region, 59 wells in the Southern Plains region and 6 wells in the Northeast British Columbia region, with an overall success rate of 87%.
- Planned drilling activity for Q1/08 includes 173 targeted natural gas wells compared to 245 in Q1/07.

North America crude oil and NGLs

	Quarterly Results			Year End Results	
	Q4/07	Q3/07	Q4/06	**2007**	2006
Crude oil and NGLs production (bbl/d)	**256,843**	252,095	249,565	**246,779**	235,253
Net wells targeting crude oil	**172**	153	188	**610**	619
Net successful wells drilled	**168**	150	174	**584**	591
Success rate	**98%**	98%	93%	**96%**	95%

- 2007 production increased 5% from 2006 to 246,779 bbl/d due to increased production from Pelican Lake, conventional heavy crude oil, and light crude oil.
- Q4/07 North America crude oil and NGLs production increased 3% from Q4/06 and increased 2% over Q3/07 levels. The majority of the incremental production volume was contributed by thermal crude oil and Pelican Lake crude oil. The issues in Q3/07 at Primrose as a result of lightning strikes and water treatment have been resolved and thermal production recovered as expected in Q4/07.
- 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, is targeted to add approximately 40,000 bbl/d of crude oil. The Primrose East Expansion received Board of Directors' sanction in 2006 and the Alberta Energy and Utilities Board regulatory approval in the first quarter of 2007. Drilling and construction are currently underway, and production is targeted to commence in 2009. Primrose East is the second phase of the 300,000 bbl/d conventional expansion plan identified to unlock the value from Canadian Natural's thermal crude oil resource base.

- In early 2007, Canadian Natural announced its proposed third phase of the thermal growth plan with a development plan for the 45,000 bbl/d Kirby In-Situ Oil Sands Project 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 as part of the Company's normal course of business.
- Development of new pads and secondary recovery conversion projects at Pelican Lake continued as expected throughout Q4/07. The response from the polymer flood project continues to be positive and the Company is moving forward on converting regions currently under waterflood to polymer flood and expanding the polymer flood to new areas. Pelican Lake production averaged approximately 36,000 bbl/d for Q4/07 compared to approximately 29,000 bbl/d for Q4/06.
- Conventional heavy crude oil production volumes decreased slightly in Q4/07 compared to Q3/07, reflecting earlier than expected declines in certain older fields.
- During Q4/07, drilling activity targeted 172 net wells including 102 wells targeting heavy crude oil, 18 wells targeting Pelican Lake crude oil, 11 wells targeting thermal crude oil and 41 wells targeting light crude oil.
- Planned drilling activity for Q1/08 includes 175 net crude oil wells, excluding stratigraphic test and service wells.

International

	Quarterly Results			Year End Results	
	Q4/07	Q3/07	Q4/06	**2007**	2006
Crude oil production (bbl/d)					
North Sea	**52,709**	52,013	61,786	**55,933**	60,056
Offshore West Africa	**27,688**	28,954	32,354	**28,520**	36,689
Natural gas production (mmcf/d)					
North Sea	**13**	10	16	**13**	15
Offshore West Africa	**14**	15	10	**12**	9
Net wells targeting crude oil	**0.6**	2.2	2.3	**7.8**	11.5
Net successful wells drilled	**0.6**	2.2	2.3	**7.8**	11.5
Success rate	**100%**	100%	100%	**100%**	100%

North Sea

- Crude oil production was down 7% in 2007 to 55,933 bbl/d from 2006 production of 60,056 bbl/d primarily due to lower than expected performance from the development of the Lyell and Columbia Fields and water injection challenges encountered at the Ninian Field.
- During Q4/07 no new wells were completed, however 1.6 net wells were drilling at quarter end. Production levels during the quarter were in line with expectations following the successful completion of planned maintenance in Q3/07 that addressed water injection challenges experienced at Ninian Field earlier in the year.
- In December 2007, the Company completed the sale of its entire working interest in the B-Block, in line with its strategy of focusing on its core producing areas. The B-Block comprises the Balmoral, Stirling and Glamis Fields. In 2007, it produced approximately 1,600 bbl/d net to Canadian Natural, representing less than 0.5% of Canadian Natural's total crude oil and NGLs production for the year.

Offshore West Africa

- Offshore West Africa's 2007 crude oil production was 28,520 bbl/d, a 22% decline from 2006 production of 36,689 bbl/d, primarily from the sanding issues experienced at Baobab.
- During Q4/07, 1.2 net crude oil and injection wells were drilled with an additional 0.6 net wells drilling at quarter end.

- The development of West Espoir was successfully completed in early 2008, with the addition of 5 production wells and 2 water injection wells during 2007.
- During 2007, the Company awarded a contract for the upgrade of the Espoir floating production, storage and offtake vessel ("FPSO"), in order to increase the throughput handling capability of the vessel. Design and procurement work commenced during the year. Production volumes will not be significantly impacted during the installation work, scheduled to be completed in late 2009.
- A deep water drilling rig has been secured for the Baobab Field. Due to the rig's ongoing prior commitments, it is now targeted to be mobilized mid-year 2008. The Company is targeting to bring a minimum 3 of 5 of the shut-in Baobab wells back into production over the course of 2008 and 2009.
- At the 90% owned and operated Olowi Field in offshore Gabon, all major construction contracts have been awarded. Platform construction and FPSO conversion are under way. The project is on schedule with drilling targeted to commence in Q2/08 and first crude oil production targeted for late 2008.

Horizon Project

- Canadian Natural achieved 90% completion of the Horizon Project at year end 2007, and remains on track for first oil in the third quarter of 2008. The remaining 10%, however, is the most labour intensive portion of the Horizon Project. Unfortunately, mid to late January and early February saw a significant deterioration in labour productivity on the construction site as much colder than normal weather seriously curtailed activity. The weather also affected the commissioning schedule of certain plants; however, at present this is not expected to have any impact on the targeted completion of Phase 1.
- As of December 31, 2007, the forecasted total costs of the Horizon Project were at 13.4% over the $6.8 billion the Board of Directors authorized as project sanction. After a thorough review of the productivity that has recently been experienced at the Horizon Project construction site, it has been determined that should no improvements in productivity be achieved through the remainder of construction, then the cost estimate for Phase 1 of the Horizon Project would need to be increased to 28% above the original $6.8 billion Board authorization. If the Horizon Project regains targeted labour efficiencies and productivity, this overage could be reduced to approximately 25% above the original $6.8 billion Board authorization. This range of outcomes will result in an on-stream cost of less than $80,000 bbl/d of capacity, including the benefits of the significant pre-build capital invested for Phase 2/3.
- In the fourth quarter of 2007, many significant milestones were achieved including completion of the tailings pond, filling of the raw water pond and preparing two tanks to receive start-up diluent in January 2008. There was some minor slippage in certain non-critical path plants where mechanical completion has moved from the end of the second quarter to early in the third quarter - with no expected impact however on targeted Project completion. The critical path plants, the Delayed Coker / Diluent Recovery Unit and Hydrotreater, remain on track for first oil in the third quarter of 2008.
- In parallel with completing major systems, the Horizon Project is getting ready for operations and has gained significant momentum. Also, all of the maintenance contracts have been awarded, with these contractors immediately mobilizing to site in the last part of the fourth quarter of 2007.
- Canadian Natural remains focused on timely completion of Phase 1, while getting ready to operate the new facilities. Meanwhile, with Tranche 2 of the next expansion, the Company was immediately able to award a contract for an additional Ore Preparation Plant to an existing contractor that is performing well. In addition, other long lead equipment (Coke Drums and Reactors) for Phase 2/3 will be delivered to site during Q1/08.

Project Summary Status	Q3/07	**Q4/07**			Q1/08	
	Actual	Actual	Q4/07 Forecast	Original Plan	Q1/08 Forecast	Original Plan
Phase 1 - Work progress (cumulative)	84%	90%	90%	94%	95%	97%
Phase 1 - Construction capital spending* (cumulative)	89%	99%	99%	92%	110%	97%

**Relative to overall Phase 1 project capital of $6.8 billion*

Accomplished to the end of the Fourth Quarter of 2007

Detailed Engineering
- Overall detailed engineering 98.5% complete and substantially complete in most areas.

Procurement
- Overall procurement progress is 99% complete.
- Awarded over $5.6 billion in purchase orders and contracts to date.
- Only one significant contract remains to be awarded for Phase 1 - mechanical for Sulphur Blocking.
- Commenced receipt and site assembly of Mine Operations Equipment (Shovels and Heavy Haul Trucks).
- Operations and maintenance service and supply agreements have been awarded.

Modularization
- Delivered an additional 54 oversized loads to site for a total of 1,560 loads, representing approximately 94% of the total requirement. Remaining deliveries consist primarily of the balance of required Mine Operations Equipment (Shovels and Heavy Haul Trucks).

Construction
- Overall construction progress is 85% complete.
- Mine overburden removal has moved 49.9 million bank cubic meters, which represents approximately 72% of the total to be moved and is 0.6 million bank cubic meters ahead of schedule.
- Main Control Room Distributed Control Systems equipment powered and tested.
- Commissioned 260kV Transmission line and turned over to operations.
- Commissioned Raw Water Pumphouse and turned over to operations.
- Completed reformer erection in Hydrogen Plant.
- Completed installation and pre-commissioning of CPI Separator Building.
- Completed the closure of Dyke 10 (external tailings pond) in Mining.
- Completed erection of Crushing Plants and conveyors in Ore Preparation Area.
- Completed Primary Separation Cells in Extraction.
- Completed construction of Main Laboratory.

Milestones for the First Quarter of 2008

- Mechanically complete Extraction Plant.
- Mechanically complete Froth Treatment Plant.
- Mechanically complete Amine Plant.
- Complete Auxiliary Boiler installation in Cogeneration.
- Complete Piping in Heat Integration.

MARKETING

	Quarterly Results			Year End Results	
	Q4/07	Q3/07	Q4/06	**2007**	2006
Crude oil and NGLs pricing					
WTI[1] benchmark price (US$/bbl)	**$ 90.63**	$ 75.33	$ 60.21	**$ 72.40**	$ 66.25
Lloyd Blend Heavy oil differential from WTI (%)	**38%**	30%	35%	**32%**	33%
Corporate average pricing before risk management (C$/bbl)	**$ 58.03**	$ 58.10	$ 47.27	**$ 55.45**	$ 53.65
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 5.69**	$ 5.32	$ 6.03	**$ 6.26**	$ 6.62
Corporate average pricing before risk management (C$/mcf)	**$ 6.28**	$ 5.87	$ 6.66	**$ 6.85**	$ 6.72

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

- In Q4/07, the Lloyd Blend heavy crude oil differential as a percent of WTI was 38%, compared to 30% in Q3/07. The Lloyd Blend heavy oil differential increased in Q4/07 due to seasonal demand fluctuations, refinery outages and turn arounds, refiners reducing their inventory levels decreasing demand, and the common carrier pipeline disruption in November 2007. Heavy oil differentials in Q1/08 have improved to approximately 27% of WTI.
- The Company continues efforts towards working with various industry groups to find new markets, such as the U.S. Gulf Coast for Western Canadian heavy crude oil and to ease the logistical constraints in getting crude oil to that area. The heavy crude oil sold to the Gulf Coast receives Mayan index equivalent pricing, a premium to the Lloyd Blend price. For Q4/07, the Mayan differential to WTI averaged US$12.30/bbl or 16%.
- During Q4/07, the Company contributed approximately 155,000 bbl/d of its heavy crude oil streams to the Western Canadian Select blend as market conditions resulted in this strategy offering the optimal pricing for bitumen.
- Natural gas inventories in North America continue to remain high in Q4/07 due to a lack of demand for natural gas and higher storage levels, resulting from the milder weather, and significant increases in liquefied natural gas (LNG) imports to the United States at the beginning of 2007, along with growing production levels in the United States. These factors contributed to depressed pricing for natural gas for North America relative to WTI.

FINANCIAL REVIEW

- Canadian Natural has structured its financial position to profitably grow its conventional crude oil and natural gas operations over the next several years and to build the financial capacity to complete the Horizon Project and other major projects. A brief summary of its strengths are:
  - A diverse asset base geographically and by product - produced in excess of 601,900 boe/d in Q4/07, comprised of approximately 44% natural gas and 56% crude oil - with 95% of production located in G8 countries with stable and secure economies.
  - Financial stability and liquidity – cash flow from operations of $6.2 billion for the fiscal year 2007, available unused bank lines of $1.4 billion at December 31, 2007 and access to capital debt markets supported by strong credit ratings.
  - 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 throughout the Horizon Project.
  - A strengthening balance sheet with debt to book capitalization of 45% and debt to EBITDA of 1.6 times, both within our targeted ranges.

- In December 2007, the Company issued $400 million of unsecured notes maturing December 2010, bearing interest at 5.50%. Subsequent to December 31, 2007, the Company issued US$1,200 million of unsecured notes under its 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. Net proceeds from the issue of these notes were used to repay bankers' acceptances.
- During 2007, the Company did not purchase any common shares for cancellation pursuant to the Normal Course Issuer Bid previously filed for the 12-month period beginning January 24, 2007 and ending January 23, 2008. The Company has decided not to renew the Normal Course Issuer Bid until subsequent to the completion of Phase 1 of the Horizon Project.
- Eighth consecutive year of dividend increases. The 2008 quarterly dividend will increase 18% from $0.085 per common share to $0.10 per common share, effective with the April 1, 2008 payment.

OUTLOOK

The Company forecasts 2008 production levels before royalties to average between 1,429 and 1,513 mmcf/d of natural gas and between 316,000 and 366,000 bbl/d of crude oil and NGLs. Q1/08 production guidance before royalties is forecast to average between 1,522 and 1,557 mmcf/d of natural gas and between 315,000 and 331,000 bbl/d of crude oil and NGLs. Detailed guidance on revised 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, 2007, Canadian Natural retained qualified independent reserve evaluators, Sproule Associates Limited (“Sproule”), and Ryder Scott Company (“Ryder Scott”), 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. Sproule evaluated the Company’s North America assets and Ryder Scott evaluated its international assets. 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 reserve 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 each of Sproule, Ryder Scott and GLJ as to the Company’s reserves.

Corporate Conventional Net Reserves

- Crude oil, natural gas and NGLs proved reserves increased by 1% replacing 110% of production. This was accomplished at all-in finding and on-stream cost of $14.28 per barrel of oil equivalent for proved reserves and $18.02 per barrel of oil equivalent for proved and probable reserves.
- In the Evaluation Reports, 46% of crude oil and NGLs proved reserves were assigned to the proved undeveloped category, a 1 percentage point decrease from the 47% recorded in 2006.
- In the Evaluation Reports, 22% 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 decreased by 1%.

North America Conventional Net Reserves

- Crude oil and NGLs proved reserves increased by 4% replacing 143% of production. Natural gas proved reserves decreased by 5% replacing 63% of 2007 production and reflected the Company’s decision to reduce capital spending on natural gas.

International Conventional Net Reserves

- North Sea proved reserves grew by 18 million barrels to 324 million barrels of oil equivalent or 16% of the total proved Company reserves.
- In Offshore West Africa proved reserves were unchanged at 139 million barrels. This is largely the result of increases in the year end crude oil price which, in the Côte d’Ivoire evaluation, accelerates project payout and increases the government royalties payable.

Horizon Oil Sands Mining Gross Lease Reserves

- The gross lease proved bitumen reserves increased by 110 million barrels to 2.385 billion barrels largely as a result of Tranche 2 capital spending commitments. The gross lease proved and probable bitumen reserves decreased 5 million barrels to 3.525 billion barrels.
- The gross lease proved synthetic crude oil reserves increased by 90 million barrels to 1.956 billion barrels. The gross leased proved and probable synthetic crude oil reserves decreased 4 million barrels to 2.958 billion barrels.

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

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

	December 31, 2006			
	Proved Developed[2]	**Proved Undeveloped[2]**	**Proved Total[2]**	**Proved and Probable[3]**
Crude oil and NGLs (mmbbl)				
North America	420	467	887	1,502
North Sea	214	85	299	422
Offshore West Africa	63	67	130	195
	697	**619**	**1,316**	**2,119**
Natural gas (bcf)				
North America	2,934	771	3,705	4,857
North Sea	17	20	37	93
Offshore West Africa	12	44	56	99
	2,963	**835**	**3,798**	**5,049**
Total reserves (mmboe)	**1,191**	**758**	**1,949**	**2,961**
Reserve replacement ratio[4] (%)			295%	472%
Cost to develop[5] ($/boe)				
10% discount	$ 1.33	$ 6.46	$ 3.32	$ 3.08
15% discount	$ 1.12	$ 5.80	$ 2.94	$ 2.66
Present value of conventional reserves[6] ($ millions)				
10% discount	$ 20,028	$ 7,469	$ 27,497	$ 37,291
15% discount	$ 17,296	$ 5,247	$ 22,543	$ 29,350

OIL SANDS MINING RESERVES[1][7]

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

	As at Dec 31, 2007		As at Dec 31, 2006	
	Proved Total	**Proved and Probable**	**Proved Total**	**Proved and Probable**
Gross reserves*, before royalties (mmbbl)				
Bitumen	**2,385**	**3,525**	2,275	3,530
Synthetic crude oil	**1,956**	**2,958**	1,866	2,962

**Represents gross lease reserves.*
Synthetic crude oil reserves are based upon upgrading of the bitumen reserves. The reserves shown for bitumen and synthetic crude oil are not additive.

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

	North America	North Sea	Offshore West Africa	Total
Proved reserves (mmbbl)				
Reserves, December 31, 2005	694	290	134	1,118
Extensions and discoveries	53	3	-	56
Infill drilling	190	14	-	204
Improved recovery	-	12	-	12
Property purchases	26	-	-	26
Property disposals	-	-	-	-
Production	(75)	(22)	(13)	(110)
Revisions of prior estimates	(1)	2	9	10
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**

	North America	North Sea	Offshore West Africa	Total
Proved and probable reserves (mmbbl)				
Reserves, December 31, 2005	1,035	417	206	1,658
Extensions and discoveries	128	3	-	131
Infill drilling	384	17	-	401
Improved recovery	-	12	-	12
Property purchases	34	-	-	34
Property disposals	-	-	-	-
Production	(75)	(22)	(13)	(110)
Revisions of prior estimates	(4)	(5)	2	(7)
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**

CONVENTIONAL NATURAL GAS RESERVES RECONCILIATION, NET OF ROYALTIES[1]

	North America	North Sea	Offshore West Africa	Total
Proved reserves (bcf)				
Reserves, December 31, 2005	2,741	29	72	2,842
Extensions and discoveries	250	-	-	250
Infill drilling	71	-	-	71
Improved recovery	3	-	-	3
Property purchases	1,111	-	-	1,111
Property disposals	(1)	-	-	(1)
Production	(433)	(5)	(3)	(441)
Revisions of prior estimates	(37)	13	(13)	(37)
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**
Proved and probable reserves (bcf)				
Reserves, December 31, 2005	3,548	69	110	3,727
Extensions and discoveries	307	-	-	307
Infill drilling	95	-	-	95
Improved recovery	4	-	-	4
Property purchases	1,466	-	-	1,466
Property disposals	(1)	-	-	(1)
Production	(433)	(5)	(3)	(441)
Revisions of prior estimates	(129)	29	(8)	(108)
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**

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

CONVENTIONAL RESERVES, BEFORE 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	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**

	December 31, 2006			
	Proved Developed[2]	**Proved Undeveloped[2]**	**Proved Total[2]**	**Proved and Probable[3]**
Crude oil and NGLs (mmbbl)				
North America	495	548	1,043	1,753
North Sea	214	85	299	421
Offshore West Africa	70	75	145	223
	779	**708**	**1,487**	**2,397**
Natural gas (bcf)				
North America	3,587	920	4,507	5,898
North Sea	17	20	37	93
Offshore West Africa	15	54	69	121
	3,619	**994**	**4,613**	**6,112**
Total reserves (mmboe)	**1,382**	**874**	**2,256**	**3,416**

CONVENTIONAL FINDING AND ON-STREAM COSTS

		2007		2006		2005		Three Year Total
Net reserve replacement expenditures ($ millions)	**$**	**3,027**	$	8,727	$	3,361	**$**	**15,115**
Net reserve additions (mmboe) [8]								
Proved		**212**		540		251		**1,003**
Proved and probable		**168**		865		337		**1,370**
Finding and on-stream costs ($/boe) [9]								
Proved	**$**	**14.28**	$	16.16	$	13.41	**$**	**15.07**
Proved and probable	**$**	**18.02**	$	10.09	$	9.97	**$**	**11.03**

(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)*
2007	*$*	*62.87*	*$*	*96.00*	*$*	*41.70*	*$*	*96.02*
2006	*$*	*51.11*	*$*	*61.05*	*$*	*41.94*	*$*	*58.93*
2005	*$*	*46.12*	*$*	*61.04*	*$*	*32.64*	*$*	*58.21*

Natural gas		*Company Average Price (C$/mcf)*		*Henry Hub Louisiana (US$/mmbtu)*		*Alberta AECO C (C$/mmbtu)*		*British Columbia Huntingdon Sumas (C$/mmbtu)*
2007	*$*	*6.48*	*$*	*6.80*	*$*	*6.52*	*$*	*6.96*
2006	*$*	*6.07*	*$*	*5.52*	*$*	*6.13*	*$*	*6.52*
2005	*$*	*9.45*	*$*	*10.08*	*$*	*9.99*	*$*	*9.53*

A foreign exchange rate of US$1.01/C$1.00 was used in the 2007 evaluation; US$0.86/C$1.00 was used in the 2006 and 2005 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 reserves using technologies implemented at the Horizon Project. The reserve values shown for bitumen and synthetic crude oil are not additive.

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

(9) Reserves finding and on-stream costs are determined by dividing total capital cash 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 2008 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 its 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 at times 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 interdependent 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 important 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, 2007 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2006.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("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 measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings in the "Financial Highlights" section.

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 exclude the effect of risk management activities and transportation and blending costs, except where noted otherwise. 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, 2007 in relation to the comparable periods in 2006 and the third quarter of 2007. The accompanying tables form an integral part of this MD&A. This MD&A is dated February 26, 2008. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2006, is available on SEDAR at www.sedar.com.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Year Ended	
	Dec 31 2007	Sep 30 2007	Dec 31 2006	**Dec 31 2007**	Dec 31 2006
Revenue, before royalties	**$ 3,200**	$ 3,073	$ 2,826	**$ 12,543**	$ 11,643
Net earnings	**$ 798**	$ 700	$ 313	**$ 2,608**	$ 2,524
Per common share – basic and diluted	**$ 1.48**	$ 1.30	$ 0.58	**$ 4.84**	$ 4.70
Adjusted net earnings from operations [(1)]	**$ 546**	$ 644	$ 412	**$ 2,406**	$ 1,664
Per common share – basic and diluted	**$ 1.02**	$ 1.19	$ 0.77	**$ 4.46**	$ 3.10
Cash flow from operations [(2)]	**$ 1,486**	$ 1,577	$ 1,293	**$ 6,198**	$ 4,932
Per common share – basic and diluted	**$ 2.75**	$ 2.92	$ 2.41	**$ 11.49**	$ 9.18
Capital expenditures, net of dispositions	**$ 1,514**	$ 1,442	$ 6,497	**$ 6,425**	$ 12,025

(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" 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" 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

	Three Months Ended			*Year Ended*	
($ millions)	***Dec 31 2007***	*Sep 30 2007*	*Dec 31 2006*	***Dec 31 2007***	*Dec 31 2006*
Net earnings as reported	***$ 798***	*$ 700*	*$ 313*	***$ 2,608***	*$ 2,524*
Stock-based compensation (recovery) expense, net of tax[(a)]	***(11)***	*54*	*120*	***134***	*95*
Unrealized risk management loss (gain), net of tax[(b)]	***593***	*57*	*(166)*	***977***	*(674)*
Unrealized foreign exchange (gain) loss, net of tax[(c)]	***(41)***	*(167)*	*145*	***(449)***	*114*
Effect of statutory tax rate and other legislative changes on future income tax liabilities[(d)]	***(793)***	*-*	*-*	***(864)***	*(395)*
Adjusted net earnings from operations	***$ 546***	*$ 644*	*$ 412*	***$ 2,406***	*$ 1,664*

(a) The Company's employee stock option plan provides for a cash payment option. Accordingly, the intrinsic value of the outstanding vested options is recorded as a liability on the Company's balance sheet and periodic changes in the intrinsic value are recognized in net earnings or are capitalized 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 the fair value of non-designated hedges flowing through net earnings. The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil and natural gas.

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

(d) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's balance sheet in determining future income tax assets and liabilities. The impact of these tax rate changes is recorded in net earnings during the period the legislation is substantively enacted. 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. Income tax rate changes in the first quarter of 2006 resulted in an increase of future income tax liabilities of approximately $110 million in the UK North Sea. Income tax rate changes in the second quarter of 2006 resulted in a reduction of future income tax liabilities of approximately $438 million in North America. Income tax rate changes in the third quarter of 2006 resulted in a reduction of future income liabilities of approximately $67 million in Côte d'Ivoire, Offshore West Africa.

Cash Flow from Operations

($ millions)	Three Months Ended **Dec 31 2007**	Three Months Ended Sep 30 2007	Three Months Ended Dec 31 2006	Year Ended **Dec 31 2007**	Year Ended Dec 31 2006
Net earnings	***$ 798***	*$ 700*	*$ 313*	***$ 2,608***	*$ 2,524*
Non-cash items:					
Depletion, depreciation and amortization	***719***	*715*	*724*	***2,863***	*2,391*
Asset retirement obligation accretion	***17***	*18*	*18*	***70***	*68*
Stock-based compensation (recovery) expense	***(16)***	*78*	*176*	***193***	*139*
Unrealized risk management loss (gain)	***845***	*76*	*(241)*	***1,400***	*(1,013)*
Unrealized foreign exchange (gain) loss	***(47)***	*(195)*	*171*	***(524)***	*134*
Deferred petroleum revenue tax expense (recovery)	***17***	*10*	*(3)*	***44***	*37*
Future income tax (recovery) expense	***(847)***	*175*	*135*	***(456)***	*652*
Cash flow from operations	***$ 1,486***	*$ 1,577*	*$ 1,293*	***$ 6,198***	*$ 4,932*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

For the year ended December 31, 2007, the Company reported net earnings of $2,608 million compared to net earnings of $2,524 million for the year ended December 31, 2006. Net earnings for the year ended December 31, 2007 included net unrealized after-tax income of $202 million related to the effects of risk management activities, fluctuations in foreign exchange rates, stock-based compensation expense and the impact of statutory tax rate and other legislative changes on future income tax liabilities, compared to net unrealized after-tax income of $860 million for the year ended December 31, 2006. Excluding these items, adjusted net earnings from operations for the year ended December 31, 2007 increased to $2,406 million from $1,664 million for the year ended December 31, 2006. The increase from the prior year was primarily due to increased sales volumes, higher realized pricing, lower realized risk management losses, and lower income tax expense. These factors were partially offset by increased production expense, higher depletion, depreciation and amortization expense, higher interest expense, and the impact of the stronger Canadian dollar relative to the US dollar.

Net earnings for the fourth quarter of 2007 were $798 million compared to net earnings of $313 million for the fourth quarter of 2006 and net earnings of $700 million for the prior quarter. Net earnings for the fourth quarter of 2007 included net unrealized after-tax income of $252 million related to the effects of risk management activities, fluctuations in foreign exchange rates, stock-based compensation (recovery) expense and the impact of statutory tax rate and other legislative changes on future income tax liabilities, compared to net unrealized after-tax expenses of $99 million for the fourth quarter of 2006 and net unrealized after-tax income of $56 million for the prior quarter. Excluding these items, adjusted net earnings from operations for the fourth quarter of 2007 increased to $546 million from $412 million for the fourth quarter of 2006 and decreased from $644 million for the prior quarter. The increase in adjusted net earnings from the fourth quarter of 2006 was primarily due to the impact of higher realized pricing and decreased production expense. These factors were partially offset by higher realized risk management losses and the impact of the stronger Canadian dollar relative to the US dollar. The decrease from the prior quarter was primarily due to increased realized risk management losses on crude oil and the impact of the stronger Canadian dollar relative to the US dollar, partially offset by higher realized pricing and decreased production costs.

The Company expects that consolidated net earnings will continue to reflect significant quarterly volatility due to the impact of risk management activities, stock-based compensation (recovery) expense and fluctuations in foreign exchange rates.

The Company's commodity hedging program reduces the risk of volatility in commodity price markets and supports the Company's cash flow for its capital expenditures throughout the Horizon Oil Sands Project ("Horizon Project") construction period. This program allows for the hedging of up to 75% of the near 12 months budgeted production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. In accordance with the policy, approximately 65% of expected crude oil volumes are hedged for 2008 and approximately 53% of expected natural gas volumes are hedged for the first quarter of 2008. Subsequent to December 31, 2007, the Company hedged 25,000 bbl/d of crude oil volumes for 2009 using WTI collars with a US$70.00 floor.

The Company's outstanding commodity related financial derivatives as at December 31, 2007 are detailed on page 48 of this MD&A.

As disclosed in note 2 to the Company's unaudited interim consolidated financial statements, commencing January 1, 2007 all derivative financial instruments are recognized at fair value on the consolidated balance sheet at each balance sheet date. As effective as the Company's hedges are against reference commodity prices, a substantial portion of the derivative financial instruments entered into by the Company have not been formally designated as hedges for accounting purposes or do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The change in the fair value of the 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, 2007.

Due to the changes in crude oil and natural gas forward pricing and the reversal of prior-period unrealized gains and losses, the Company recorded a net unrealized loss of $1,400 million ($977 million after-tax) on its commodity risk management activities for the year ended December 31, 2007, including an $845 million ($593 million after-tax) unrealized loss for the three months ended December 31, 2007. Mark-to-market unrealized gains and losses do not impact the Company's current cash flow or its ability to finance ongoing capital programs. The Company continues to believe that its risk management program meets its objective of securing funding for its capital projects and does not intend to alter its current strategy of obtaining price certainty for its crude oil and natural gas sales. For further details, refer to Risk Management Activities on page 38 of this MD&A.

The Company also recorded a $193 million ($134 million after-tax) stock-based compensation expense as a result of the 17% increase in the Company's share price for the year ended December 31, 2007, and a $16 million ($11 million after-tax) stock-based compensation recovery as a result of the 4% decrease in the Company's share price for the three months ended December 31, 2007 (Company's share price as at: December 31, 2007 – C$72.58; September 30, 2007 – C$75.56; December 31, 2006 – C$62.15). 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 the 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 as part of the Horizon Project during the construction period. The stock-based compensation liability at December 31, 2007 reflected the Company's potential cash liability assuming all the vested options had been surrendered for a cash payout at the market price on December 31, 2007. In periods when substantial share price changes occur, the Company's net 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.

Cash flow from operations for the year ended December 31, 2007 increased to $6,198 million from $4,932 million for the year ended December 31, 2006. The increase from the comparable period in 2006 was primarily due to increased sales volumes, higher realized pricing, and lower realized risk management losses, offset by increased production expense, higher interest costs, higher current taxes, and the impact of the stronger Canadian dollar relative to the US dollar.

Cash flow from operations for the fourth quarter of 2007 increased to $1,486 million from $1,293 million for the fourth quarter of 2006, and decreased from $1,577 million for the prior quarter. The increase from the fourth quarter of 2006 was primarily due to the impact of higher realized pricing and lower production expense, partially offset by increased realized risk management losses and the impact of the stronger Canadian dollar relative to the US dollar. The decrease from the prior quarter was primarily due to lower natural gas production, increased realized risk management losses on crude oil, higher current taxes, and the impact of the stronger Canadian dollar relative to the US dollar, partially offset by increased crude oil production and lower production costs.

Total production before royalties increased 5% to average 609,206 boe/d for the year ended December 31, 2007 from 580,724 boe/d for the year ended December 31, 2006. Production for the fourth quarter of 2007 decreased 2% to 601,908 boe/d from 613,764 boe/d for the fourth quarter of 2006 and 1% from 607,484 boe/d for the prior quarter.

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 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

($ millions, except per common share amounts)		Dec 31 2006		Sep 30 2006		Jun 30 2006		Mar 31 2006
Revenue, before royalties (1)	$	2,826	$	3,108	$	3,041	$	2,668
Net earnings	$	313	$	1,116	$	1,038	$	57
Net earnings per common share								
– Basic and diluted	$	0.58	$	2.08	$	1.93	$	0.11

(1) Blending costs that were netted against gross revenues in prior periods have been reclassified to transportation expense to conform to the presentation adopted in the fourth quarter of 2006.

Net earnings 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 financial instruments, increased depletion, depreciation and amortization charges, 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 demand growth, continued 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 fluctuations in demand for natural gas and high inventory storage levels as a result of seasonality, milder overall weather experienced during 2007 and 2006, and increased liquefied natural gas imports into the US during the first half of 2007.

- 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, development of West and East Espoir, and additional sales volumes from the Anadarko Canada Corporation ("ACC") acquisition completed in the fourth quarter of 2006.

- Natural gas sales volumes

  Natural gas sales volumes primarily reflected additional natural gas volumes as a result of the ACC acquisition and internally generated growth. The increases were partially offset by production declines due to the Company's strategic reduction in natural gas drilling activity.

- Foreign exchange rates

  A general strengthening of the Canadian dollar relative to the US dollar has decreased 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 balances and the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars, offset by the impact of cross currency swaps.

- Commodity hedges

  Net earnings have fluctuated due to the recognition of realized and unrealized gains and losses from the mark-to-market of the Company's commodity hedges.

- Changes in income tax expense

  Income tax expense and recovery fluctuations include statutory tax rate and other legislative changes enacted or substantively enacted in the various periods.

- Stock-based compensation

  Net earnings have fluctuated due to the recognition of realized and unrealized expenses and recoveries from the mark-to-market of the Company's stock-based compensation liability. Stock-based compensation expense 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 production growth and industry-wide inflationary cost pressures in all segments.

- Depletion, depreciation and amortization

  Depletion, depreciation and amortization expense has increased primarily due to overall increases in finding and development costs associated with crude oil and natural gas exploration, increased estimated future costs to develop the Company's proved undeveloped reserves, and a higher depletion base in North America related to the ACC acquisition, together with the impact of higher sales volumes.

OPERATING HIGHLIGHTS

	Three Months Ended			Year Ended	
	Dec 31 2007	Sep 30 2007	Dec 31 2006	**Dec 31 2007**	Dec 31 2006
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 58.03**	$ 58.10	$ 47.27	**$ 55.45**	$ 53.65
Royalties	**6.66**	6.65	4.10	**5.94**	4.48
Production expense	**11.53**	13.13	12.32	**13.34**	12.29
Netback	**$ 39.84**	$ 38.32	$ 30.85	**$ 36.17**	$ 36.88
Natural gas ($/mcf) (1)					
Sales price (2)	**$ 6.28**	$ 5.87	$ 6.66	**$ 6.85**	$ 6.72
Royalties	**0.94**	0.89	1.26	**1.11**	1.29
Production expense	**0.91**	0.88	0.86	**0.91**	0.82
Netback	**$ 4.43**	$ 4.10	$ 4.54	**$ 4.83**	$ 4.61
Barrels of oil equivalent ($/boe) (1)					
Sales price (2)	**$ 49.23**	$ 47.96	$ 43.91	**$ 49.05**	$ 47.92
Royalties	**6.21**	6.07	5.62	**6.26**	5.89
Production expense	**8.85**	9.62	9.16	**9.75**	9.14
Netback	**$ 34.17**	$ 32.27	$ 29.13	**$ 33.04**	$ 32.89

(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 2007	Sep 30 2007	Dec 31 2006	**Dec 31 2007**	Dec 31 2006
WTI benchmark price (US$/bbl)	**$ 90.63**	$ 75.33	$ 60.21	**$ 72.40**	$ 66.25
Dated Brent benchmark price (US$/bbl)	**$ 88.65**	$ 74.85	$ 59.68	**$ 72.59**	$ 65.18
Differential to LLB blend (US$/bbl)	**$ 34.07**	$ 22.69	$ 21.31	**$ 23.05**	$ 21.69
LLB blend differential from WTI (%)	**38%**	30%	35%	**32%**	33%
Condensate benchmark price (US$/bbl)	**$ 90.89**	$ 75.93	$ 59.59	**$ 72.88**	$ 66.24
NYMEX benchmark price (US$/mmbtu)	**$ 7.03**	$ 6.13	$ 6.61	**$ 6.92**	$ 7.26
AECO benchmark price (C$/GJ)	**$ 5.69**	$ 5.32	$ 6.03	**$ 6.26**	$ 6.62
US / Cdn dollar average exchange rate	**$ 1.0193**	$ 0.9565	$ 0.8781	**$ 0.9304**	$ 0.8818

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$72.40 per bbl for the year ended December 31, 2007, an increase of 9% from US$66.25 per bbl for the year ended December 31, 2006. For the fourth quarter of 2007, WTI averaged US$90.63 per bbl, an increase of 51% from US$60.21 per bbl for the fourth quarter of 2006, and an increase of 20% from US$75.33 per bbl for the prior quarter. Increases in WTI pricing in the fourth quarter reflected continued strong demand for crude oil and continued geopolitical events resulting in increased market uncertainty and price volatility. The WTI reference price, in relation to other world benchmark crude oils, also benefited from the easing of logistical constraints experienced during the second quarter, particularly at Cushing, Oklahoma.

Crude oil sales contracts for the Company’s North Sea and Offshore West Africa segments are typically based on Brent pricing, which continued to benefit from strong European and Asian demand in 2007. Dated Brent (“Brent”) averaged US$72.59 per bbl for the year ended December 31, 2007, an increase of 11% from US$65.18 per bbl for the year ended December 31, 2006. For the fourth quarter of 2007, Brent averaged US$88.65 per bbl, an increase of 49% compared to US$59.68 per bbl for the fourth quarter of 2006, and an increase of 18% from US$74.85 per bbl for the prior quarter. During the fourth quarter, the differential between Brent and WTI returned to more historical levels as logistical constraints at Cushing, Oklahoma were resolved.

Company-wide, realized crude oil prices for the year ended December 31, 2007 increased slightly as a result of higher benchmark WTI pricing and a narrower Heavy Differential in North America. The Heavy Differential averaged 32% for the year ended December 31, 2007 compared to 33% for the year ended December 31, 2006. For the fourth quarter of 2007, the Heavy Differential averaged 38% compared to 35% for the fourth quarter of 2006. The widening of the Heavy Differential from the comparable period in 2006 was primarily due to increased heavy crude oil production from Western Canada and reduced demand from US Midwest refineries due to plant maintenance and unplanned outages. In 2007, realized prices continued to be adversely impacted by the stronger Canadian dollar.

The Company anticipates continued volatility in the crude oil pricing benchmarks due to the unpredictable nature of geopolitical events and potential unplanned refinery outages. The Heavy Differential is expected to continue to reflect seasonal demand fluctuations and refinery cracking margins.

NYMEX natural gas prices averaged US$6.92 per mmbtu for the year ended December 31, 2007, a decrease of 5% from US$7.26 per mmbtu for the year ended December 31, 2006. For the fourth quarter of 2007, the NYMEX natural gas price averaged US$7.03 per mmbtu, an increase of 6% from US$6.61 per mmbtu for the fourth quarter of 2006, and an increase of 15% from US$6.13 per mmbtu for the prior quarter. AECO natural gas prices decreased 5% to average $6.26 per GJ for the year ended December 31, 2007, compared to $6.62 per GJ for the year ended December 31, 2006. For the fourth quarter of 2007 AECO natural gas prices averaged $5.69 per GJ, a decrease of 6% from $6.03 per GJ for the fourth quarter of 2006, and an increase of 7% from $5.32 per GJ for the prior quarter. Fluctuations in natural gas prices from the comparable periods in 2006 were primarily related to lower overall demand and higher storage levels, resulting from the milder weather, reduced economic activity in the US, and higher liquefied natural gas imports into the US in the first half of 2007. Natural gas inventory levels in North America continued to remain high throughout 2007 due to stable production levels in the US, offset by production declines in Canada due to reduced drilling activity.

Operating, Royalty and Capital Costs

Strong commodity prices in recent years have resulted in increased demand and costs for oilfield services worldwide. This has lead to inflationary operating and capital cost pressures throughout the North America crude oil and natural gas industry, particularly related to drilling activities and oil sands developments. The strong commodity price environment has also impacted costs in international basins, due in large part to the high demand for offshore drilling rigs.

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. 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_2 annually. In the UK, GHG regulations have been in effect since 2005. The Company has strategies in place to ensure compliance with any requirements now in effect. The additional requirements of enacted and proposed GHG legislation will add to the cost of executing projects company-wide.

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.

Further, on October 25, 2007, the Province of Alberta issued certain details of its proposed changes to the Alberta crude oil and natural gas royalty regime, effective January 1, 2009. These proposed changes include:

- The implementation of a sliding scale for oil sands royalties ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout depending on benchmark crude oil pricing; and
- New royalty formulas for conventional crude oil and natural gas that are to operate on sliding scales ranging up to 50% determined by commodity prices and well productivity.

The Company is currently awaiting finalization of the royalty implementation regulations, however it expects that its 2009 and future Alberta royalty payments will increase as a result of the proposed royalty changes and that its level of activity in Alberta in aggregate will be reduced from what it otherwise would have been in the absence of such royalty changes.

PRODUCT PRICES

	Three Months Ended			Year Ended	
	Dec 31 2007	Sep 30 2007	Dec 31 2006	**Dec 31 2007**	Dec 31 2006
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 50.49**	$ 52.47	$ 40.27	**$ 49.16**	$ 46.52
North Sea	**$ 83.44**	$ 77.55	$ 67.72	**$ 74.99**	$ 72.62
Offshore West Africa	**$ 81.89**	$ 70.52	$ 63.50	**$ 71.68**	$ 67.99
Company average	**$ 58.03**	$ 58.10	$ 47.27	**$ 55.45**	$ 53.65
Natural gas ($/mcf) (1) (2)					
North America	**$ 6.31**	$ 5.88	$ 6.70	**$ 6.87**	$ 6.77
North Sea	**$ 3.62**	$ 5.26	$ 3.48	**$ 4.26**	$ 2.66
Offshore West Africa	**$ 5.49**	$ 5.31	$ 5.72	**$ 5.68**	$ 5.37
Company average	**$ 6.28**	$ 5.87	$ 6.66	**$ 6.85**	$ 6.72
Company average ($/boe) (1) (2)	**$ 49.23**	$ 47.96	$ 43.91	**$ 49.05**	$ 47.92
Percentage of gross revenue (2) (excluding midstream revenue)					
Crude oil and NGLs	**66%**	67%	60%	**62%**	64%
Natural gas	**34%**	33%	40%	**38%**	36%

(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 3% to average $55.45 per bbl for the year ended December 31, 2007 from $53.65 per bbl for the year ended December 31, 2006. Realized crude oil prices for the fourth quarter of 2007 increased 23% to average $58.03 per bbl from $47.27 per bbl for the fourth quarter of 2006, and decreased marginally from $58.10 per bbl for the prior quarter. The Company's realized crude oil prices increased from the comparable periods in 2006 as a result of higher benchmark WTI pricing, largely offset by the impact of the stronger Canadian dollar. The decrease from the prior quarter primarily reflected the widening of the Heavy Differential and the impact of the stronger Canadian dollar, partially offset by higher benchmark WTI pricing.

The Company's realized natural gas price increased 2% to average $6.85 per mcf for the year ended December 31, 2007 from $6.72 per mcf for the year ended December 31, 2006. In the fourth quarter of 2007, the Company's realized natural gas price decreased 6% to average $6.28 per mcf from $6.66 per mcf in the fourth quarter of 2006, and increased 7% from $5.87 per mcf for the prior quarter. Fluctuations in natural gas prices from the comparable periods in 2006 and the third quarter of 2007 were primarily related to the impact of both weather and storage levels.

North America

North America realized crude oil prices increased 6% to average $49.16 per bbl for the year ended December 31, 2007 from $46.52 per bbl for the year ended December 31, 2006. Realized crude oil prices for the fourth quarter of 2007 averaged $50.49 per bbl, a 25% increase from $40.27 per bbl for the fourth quarter of 2006, and decreased 4% from $52.47 per bbl for the prior quarter. The increase in realized crude oil prices from the fourth quarter of 2006 was due to the increase in WTI benchmark pricing, largely offset by the impact of the stronger Canadian dollar and the widening of the Heavy Differential, while the decrease from the prior quarter was due to the widening Heavy Differential and the impact of the stronger Canadian dollar relative to the US dollar, partially offset by the increase in WTI benchmark pricing.

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 155,000 bbl/d of heavy crude oil blends to the Western Canadian Select stream.

North America realized natural gas prices increased 1% to average $6.87 per mcf for the year ended December 31, 2007 from $6.77 per mcf for the year ended December 31, 2006. The realized natural gas price for the fourth quarter of 2007 averaged $6.31 per mcf, a 6% decrease from $6.70 per mcf for the fourth quarter of 2006, and a 7% increase from $5.88 per mcf for the prior quarter. Fluctuations in natural gas prices from the comparable periods in 2006 and the third quarter of 2007 were primarily related to the impact of weather and storage levels.

A comparison of the price received for the Company's North America production by product type is as follows:

	Dec 31 2007	Sep 30 2007	Dec 31 2006
Wellhead Price (1) (2)			
Light / medium crude oil and NGLs (C$/bbl)	**$ 74.96**	$ 67.55	$ 54.11
Pelican Lake crude oil (C$/bbl)	**$ 47.01**	$ 48.91	$ 37.89
Primary heavy crude oil (C$/bbl)	**$ 43.30**	$ 47.47	$ 36.16
Thermal heavy crude oil (C$/bbl)	**$ 42.76**	$ 48.99	$ 36.06
Natural gas (C$/mcf)	**$ 6.31**	$ 5.88	$ 6.70

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

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

North Sea

North Sea realized crude oil prices increased 3% to average $74.99 per bbl for the year ended December 31, 2007 from $72.62 per bbl for the year ended December 31, 2006. Realized crude oil prices for the fourth quarter of 2007 averaged $83.44 per bbl, a 23% increase from $67.72 per bbl for the fourth quarter of 2006, and an 8% increase from $77.55 per bbl for the prior quarter. Realized crude oil prices in the North Sea during the fourth quarter continued to benefit from the impact of strong European and Asian demand, partially offset by the impact of the stronger Canadian dollar relative to the US dollar.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 5% to average $71.68 per bbl for the year ended December 31, 2007 from $67.99 per bbl for the year ended December 31, 2006. Realized crude oil prices for the fourth quarter of 2007 averaged $81.89 per bbl, a 29% increase from $63.50 per bbl for the fourth quarter of 2006, and a 16% increase from $70.52 per bbl for the prior quarter. As all revenue in Offshore West Africa is currently recognized on a liftings basis, realized crude oil prices per barrel in any particular quarter are dependant on the frequency and timing of liftings of each field, as well as the terms of the related sales contracts. Realized crude oil prices in Offshore West Africa during the fourth quarter continued to benefit from the impact of strong European and Asian demand, offset by the impact of the stronger Canadian dollar relative to the US dollar.

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 inventory volumes by segment, which have not been recognized in revenue, were as follows:

(bbl)	**Dec 31 2007**	Sep 30 2007	Dec 31 2006
North America, related to pipeline fill	**1,097,526**	1,097,526	1,097,526
North Sea, related to timing of liftings	**1,032,723**	260,648	910,796
Offshore West Africa, related to timing of liftings	**8,578**	587,486	113,774
	2,138,827	1,945,660	2,122,096

In the fourth quarter of 2007, net production of approximately 193,000 barrels of crude oil produced in the Company's international operations was deferred and included in inventory at December 31, 2007. Notwithstanding the increase in inventory, cash flow from operations increased by approximately $8 million in the fourth quarter of 2007 as increased cash flow derived from additional sales volumes in Offshore West Africa more than offset the decrease in cash flows due to lower sales volumes in the North Sea.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2007	Sep 30 2007	Dec 31 2006	**Dec 31 2007**	Dec 31 2006
Crude oil and NGLs (bbl/d)					
North America	**256,843**	252,095	249,565	**246,779**	235,253
North Sea	**52,709**	52,013	61,786	**55,933**	60,056
Offshore West Africa	**27,688**	28,954	32,354	**28,520**	36,689
	337,240	333,062	343,705	**331,232**	331,998
Natural gas (mmcf/d)					
North America	**1,562**	1,622	1,594	**1,643**	1,468
North Sea	**13**	10	16	**13**	15
Offshore West Africa	**14**	15	10	**12**	9
	1,589	1,647	1,620	**1,668**	1,492
Total barrel of oil equivalent (boe/d)	**601,908**	607,484	613,764	**609,206**	580,724
Product mix					
Light/medium crude oil and NGLs	**23%**	22%	24%	**23%**	26%
Pelican Lake crude oil	**6%**	6%	5%	**6%**	5%
Primary heavy crude oil	**15%**	16%	15%	**15%**	16%
Thermal heavy crude oil	**12%**	11%	12%	**11%**	11%
Natural gas	**44%**	45%	44%	**45%**	42%

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2007	Sep 30 2007	Dec 31 2006	**Dec 31 2007**	Dec 31 2006
Crude oil and NGLs (bbl/d)					
North America	**217,886**	213,680	217,751	**210,769**	205,382
North Sea	**52,586**	51,917	61,658	**55,825**	59,940
Offshore West Africa	**25,123**	26,158	30,817	**26,012**	35,212
	295,595	291,755	310,226	**292,606**	300,534
Natural gas (mmcf/d)					
North America	**1,327**	1,373	1,291	**1,378**	1,185
North Sea	**13**	10	16	**13**	15
Offshore West Africa	**12**	14	9	**11**	9
	1,352	1,397	1,316	**1,402**	1,209
Total barrel of oil equivalent (boe/d)	**520,887**	524,417	529,515	**526,193**	502,024

Daily production and per barrel 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 609,206 boe/d for the year ended December 31, 2007, a 5% increase from the year ended December 31, 2006. Fourth quarter total production in 2007 averaged 601,908 boe/d, a decrease of 2% from 613,764 boe/d for the fourth quarter of 2006, and a decrease of 1% from 607,484 boe/d for the prior quarter.

Total crude oil and NGLs production for the year ended December 31, 2007 decreased marginally to 331,232 bbl/d from 331,998 bbl/d for the year ended December 31, 2006. For the fourth quarter of 2007, production decreased 2% to 337,240 bbl/d from 343,705 bbl/d for the fourth quarter of 2006 and increased 1% from 333,062 bbl/d for the prior quarter. The decrease from the comparable periods of 2006 was primarily due to lower production in the North Sea due to the timing of planned maintenance activities and reduced production from the Baobab Field in Offshore West Africa, offset by increased production in North America. Crude oil and NGLs production in the fourth quarter of 2007 was within the Company’s previously issued guidance of 321,000 to 344,000 bbl/d.

Natural gas production continued to represent the Company’s largest product offering in 2007, accounting for 45% of the Company’s total production. Natural gas production for the year ended December 31, 2007 averaged 1,668 mmcf/d compared to 1,492 mmcf/d for the year ended December 31, 2006. For the fourth quarter of 2007, natural gas production averaged 1,589 mmcf/d compared to 1,620 mmcf/d for the fourth quarter of 2006 and 1,647 mmcf/d for the prior quarter. Natural gas production generally reflects peak production levels in the spring of each year due to the higher proportion of wells drilled during the winter months, followed by natural production declines throughout the remainder of the year. The decrease in natural gas production from the fourth quarter of 2006 and the prior quarter primarily reflected production declines due to the Company’s strategic reduction in natural gas drilling activity. Fourth quarter natural gas production was within the Company’s previously issued guidance of 1,577 to 1,616 mmcf/d.

For 2008, annual production guidance is targeted to average between 316,000 and 366,000 bbl/d of crude oil and NGLs and between 1,429 and 1,513 mmcf/d of natural gas. First quarter 2008 production guidance is targeted to average between 315,000 and 331,000 bbl/d of crude oil and NGLs and between 1,522 and 1,557 mmcf/d of natural gas.

North America

North America crude oil and NGLs production for the year ended December 31, 2007 increased 5% to average 246,779 bbl/d, up from 235,253 bbl/d for the year ended December 31, 2006. Production for the fourth quarter of 2007 increased 3% to average 256,843 bbl/d from 249,565 bbl/d for the fourth quarter of 2006, and increased 2% from 252,095 bbl/d for the prior quarter. The increase in crude oil and NGLs production from the prior periods was primarily due to the results from the Pelican Lake project and the cyclic nature of the Company's thermal production.

North America natural gas production increased 12% to average 1,643 mmcf/d for the year ended December 31, 2007, up from 1,468 mmcf/d for the year ended December 31, 2006. For the fourth quarter of 2007, natural gas production decreased 2% to 1,562 mmcf/d from 1,594 mmcf/d for the fourth quarter of 2006, and decreased 4% from 1,622 mmcf/d for the prior quarter. The increase in natural gas production from the year ended December 31, 2006 reflected the full year impact of the ACC acquisition, partially offset by production declines throughout 2007 due to the Company's strategic decision to reduce natural gas drilling activity.

North Sea

North Sea crude oil production averaged 55,933 bbl/d for the year ended December 31, 2007, a decrease of 7% from 60,056 bbl/d for the year ended December 31, 2006. Crude oil production for the fourth quarter of 2007 decreased 15% to 52,709 bbl/d from 61,786 bbl/d for the fourth quarter of 2006 and increased marginally from 52,013 bbl/d for the prior quarter. Production levels for the fourth quarter of 2007 were in line with expectations, with the increase from the prior quarter primarily related to the planned maintenance shutdowns carried out in the third quarter and the successful resolution of water injection problems previously experienced at Ninian.

Offshore West Africa

Offshore West Africa crude oil production decreased 22% to average 28,520 bbl/d for the year ended December 31, 2007 from 36,689 bbl/d for the year ended December 31, 2006. Fourth quarter 2007 production decreased 14% to 27,688 bbl/d from 32,354 bbl/d for the fourth quarter of 2006, and was marginally down from 28,954 bbl/d for the prior quarter. Production decreased from the comparable periods in 2006 due to continued challenges with sand production at the Baobab Field where 5 of 10 production wells remain shut in. The Company has secured a deepwater rig, expected in mid-year 2008, that should enable the Company to execute its plan to return certain of the shut in wells to production over the course of 2008 and 2009.

ROYALTIES

	Three Months Ended			Year Ended	
	Dec 31 2007	Sep 30 2007	Dec 31 2006	**Dec 31 2007**	Dec 31 2006
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 7.66**	$ 8.00	$ 5.13	**$ 7.19**	$ 5.86
North Sea	**$ 0.19**	$ 0.14	$ 0.14	**$ 0.14**	$ 0.13
Offshore West Africa	**$ 7.59**	$ 6.81	$ 3.02	**$ 6.40**	$ 2.81
Company average	**$ 6.66**	$ 6.65	$ 4.10	**$ 5.94**	$ 4.48
Natural gas ($/mcf) [1]					
North America	**$ 0.95**	$ 0.90	$ 1.29	**$ 1.12**	$ 1.31
North Sea	**$ -**	$ -	$ -	**$ -**	$ -
Offshore West Africa	**$ 0.52**	$ 0.51	$ 0.27	**$ 0.51**	$ 0.22
Company average	**$ 0.94**	$ 0.89	$ 1.26	**$ 1.11**	$ 1.29
Company average ($/boe) [1]	**$ 6.21**	$ 6.07	$ 5.62	**$ 6.26**	$ 5.89
Percentage of revenue [2]					
Crude oil and NGLs	**11%**	11%	9%	**11%**	8%
Natural gas	**15%**	15%	19%	**16%**	19%
Boe	**13%**	13%	13%	**13%**	12%

(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, 2007 continue to reflect strong realized crude oil prices and the impact of the full recovery of the Company's capital investments in the Primrose North and South Fields in the fourth quarter of 2006. Upon full recovery, Crown royalty rates on the Primrose North and South Fields increased from 1% of revenue to 25% of revenue less operating, capital and abandonment costs. Crude oil and NGLs royalties averaged approximately 15% of revenues for the year ended December 31, 2007, compared to 13% for 2006. Crude oil and NGLs royalties per bbl are anticipated to average 14% to 16% of gross revenue for 2008.

Natural gas royalties per mcf generally fluctuate with natural gas prices. Natural gas royalties averaged approximately 15% of revenues for the fourth quarter of 2007 compared to 19% for the fourth quarter of 2006 and 15% for the prior quarter. Natural gas royalties decreased in the third and fourth quarter of 2007 compared to prior periods in 2006 due to the impact of certain adjustments, and are anticipated to average 17% to 20% of gross revenue for 2008.

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 Company. Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Government. The Government's 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 9% for the fourth quarter of 2007 compared to 5% for fourth quarter of 2006 and 10% for the prior quarter. The increase in royalty rates from the comparable period for 2006 was due to the Company's full recovery of its capital investment in the Espoir Field in 2007 and the resulting increase in profit oil on which the Government's entitlement is based. Offshore West Africa royalty rates are anticipated to average 12% to 17% of gross revenue for 2008.

PRODUCTION EXPENSE

	Three Months Ended			Year Ended	
	Dec 31 2007	Sep 30 2007	Dec 31 2006	**Dec 31 2007**	Dec 31 2006
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 10.54**	$ 11.69	$ 12.13	**$ 12.26**	$ 11.73
North Sea	**$ 18.95**	$ 23.61	$ 14.76	**$ 20.78**	$ 17.57
Offshore West Africa	**$ 9.32**	$ 7.00	$ 10.05	**$ 8.32**	$ 7.45
Company average	**$ 11.53**	$ 13.13	$ 12.32	**$ 13.34**	$ 12.29
Natural gas ($/mcf) (1)					
North America	**$ 0.90**	$ 0.87	$ 0.84	**$ 0.90**	$ 0.81
North Sea	**$ 1.50**	$ 2.29	$ 1.54	**$ 2.17**	$ 1.40
Offshore West Africa	**$ 1.89**	$ 1.39	$ 2.01	**$ 1.48**	$ 1.19
Company average	**$ 0.91**	$ 0.88	$ 0.86	**$ 0.91**	$ 0.82
Company average ($/boe) (1)	**$ 8.85**	$ 9.62	$ 9.16	**$ 9.75**	$ 9.14

(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, 2007 increased 5% to $12.26 per bbl from $11.73 per bbl for the year ended December 31, 2006. For the fourth quarter of 2007 production expense decreased 13% to $10.54 per bbl from $12.13 per bbl for the fourth quarter of 2006 and decreased 10% from $11.69 per bbl for the prior quarter. The decrease in production expense per barrel for the fourth quarter of 2007 was a result of the timing of primary steam cycles, lower cost of natural gas for fuel for the Company's thermal operations, and higher production volumes in Pelican Lake and thermal production areas, where a large portion of costs are fixed in nature.

North America natural gas production expense for the year ended December 31, 2007 increased 11% to $0.90 per mcf from $0.81 per mcf for the year ended December 31, 2006. For the fourth quarter of 2007 production expense increased 7% to $0.90 per mcf from $0.84 per mcf for the fourth quarter of 2006 and was up slightly from $0.87 per mcf for the prior quarter. The increase in production expense per mcf is a result of lower sales volumes on the fixed cost portion of production costs, partially offset by the stabilization of natural gas well servicing costs in the last half of 2007.

North Sea

North Sea crude oil production expense varied on a per barrel basis from the prior quarter due to the completion of planned maintenance shutdowns in the third quarter of 2007, varying production volumes on a relatively fixed cost base, the timing of liftings from various fields, and the impact of the stronger Canadian dollar.

Offshore West Africa

Offshore West Africa crude oil production expense on a per barrel basis varied from the prior quarter primarily due to the impact of the timing of liftings at Baobab and Espoir, resulting in a greater proportion of relatively higher fixed cost Baobab sourced liftings in the quarter. Production expense was positively impacted by the impact of the stronger Canadian dollar.

MIDSTREAM

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2007**	Sep 30 2007	Dec 31 2006	**Dec 31 2007**	Dec 31 2006
Revenue	**$ 19**	$ 19	$ 18	**$ 74**	$ 72
Production expense	**6**	5	6	**22**	23
Midstream cash flow	**13**	14	12	**52**	49
Depreciation	**2**	2	2	**8**	8
Segment earnings before taxes	**$ 11**	$ 12	$ 10	**$ 44**	$ 41

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 2007	Sep 30 2007	Dec 31 2006	**Dec 31 2007**	Dec 31 2006
Expense ($ millions)	**$ 717**	$ 713	$ 722	**$ 2,855**	$ 2,383
$/boe (2)	**$ 12.99**	$ 12.68	$ 12.80	**$ 12.84**	$ 11.27

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

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

Depletion, Depreciation and Amortization ("DD&A") for the year ended December 31, 2007 increased in total and on a boe basis from the year ended December 31, 2006. DD&A for the fourth quarter of 2007 was consistent with the prior quarter and the fourth quarter of 2006. The increase in DD&A expense from the prior year was primarily due to overall increases in finding and development costs associated with crude oil and natural gas exploration, increased estimated future costs to develop the Company's proved undeveloped reserves, and a higher depletion base in North America related to the ACC acquisition, together with the impact of higher sales volumes.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three Months Ended			Year Ended	
	Dec 31 2007	Sep 30 2007	Dec 31 2006	**Dec 31 2007**	Dec 31 2006
Expense ($ millions)	**$ 17**	$ 18	$ 18	**$ 70**	$ 68
$/boe (1)	**$ 0.31**	$ 0.32	$ 0.32	**$ 0.32**	$ 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 and quarter ended December 31, 2007 was consistent with the comparable periods.

ADMINISTRATION EXPENSE

	Three Months Ended			Year Ended	
	Dec 31 2007	Sep 30 2007	Dec 31 2006	**Dec 31 2007**	Dec 31 2006
Net expense ($ millions)	**$ 42**	$ 53	$ 57	**$ 208**	$ 180
$/boe (1)	**$ 0.76**	$ 0.94	$ 1.01	**$ 0.93**	$ 0.85

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

Administration expense for the year ended December 31, 2007 increased in total and on a boe basis from the year ended December 31, 2006 primarily due to increased staffing costs, including costs related to the Company's share bonus program. The decrease in administration expense from the prior quarter in 2007 was primarily due to decreased insurance costs and lower costs associated with employee bonus programs.

STOCK-BASED COMPENSATION (RECOVERY) EXPENSE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2007**	Sep 30 2007	Dec 31 2006	**Dec 31 2007**	Dec 31 2006
Stock-based compensation (recovery) expense	**$ (16)**	$ 78	$ 176	**$ 193**	$ 139

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 since 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 $193 million ($134 million after-tax) stock-based compensation expense as a result of the 17% increase in the Company's share price for the year ended December 31, 2007, and a $16 million ($11 million after-tax) stock-based compensation recovery as a result of the 4% decrease in the Company's share price for the three months ended December 31, 2007 (Company's share price as at: December 31, 2007 – C$72.58; September 30, 2007 – C$75.56; December 31, 2006 – C$62.15;). As required by GAAP, the Company's outstanding stock options are valued 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, 2007, the Company capitalized $58 million in stock-based compensation on the Horizon Project (December 31, 2006 - $79 million). 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, 2007. In periods when substantial stock price changes occur, the Company is subject to significant earnings volatility.

For the year ended December 31, 2007, the Company paid $375 million for stock options surrendered for cash settlement (December 31, 2006 - $264 million).

INTEREST EXPENSE

	Three Months Ended			Year Ended	
($ millions, except per boe amounts)	**Dec 31 2007**	Sep 30 2007	Dec 31 2006	**Dec 31 2007**	Dec 31 2006
Interest expense, gross	**$ 160**	$ 160	$ 128	**$ 632**	$ 336
Less: capitalized interest, Horizon Project	**109**	95	66	**356**	196
Interest expense, net	**$ 51**	$ 65	$ 62	**$ 276**	$ 140
$/boe [(1)]	**$ 0.92**	$ 1.15	$ 1.08	**$ 1.24**	$ 0.66
Average effective interest rate	**5.5%**	5.7%	5.6%	**5.5%**	5.7%

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

Gross interest expense increased from the comparable periods in 2006 substantially due to increased debt levels associated with the ACC acquisition in the fourth quarter of 2006 and the ongoing financing of Horizon Project capital expenditures.

The Company's average effective interest rate for the periods ended December 31, 2007 reflected the impact of the stronger Canadian dollar, offset by higher cost US dollar denominated debt issued in March 2007 and the impact of higher short-term lending rates on the Company's floating rate debt due to credit market uncertainty.

In 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. These derivative financial instruments are not intended for trading or speculative purposes.

As disclosed in note 2 to the Company's unaudited interim consolidated financial statements, commencing January 1, 2007 the Company adopted new accounting standards issued by the Canadian Institute of Chartered Accountants relating to the accounting for and disclosure of financial instruments and comprehensive income.

Adoption of these standards required the Company to record all of its derivative financial instruments on the balance sheet at estimated fair value as at January 1, 2007, including those designated as hedges. Designated hedges, other than cross currency swaps, were previously not recognized on the balance sheet but were disclosed in the notes to the financial statements. The adjustment to recognize the designated hedges on the balance sheet was recorded as an adjustment to the opening balance of retained earnings or accumulated other comprehensive income, as appropriate.

With the exception of the foreign currency translation adjustment, these standards were adopted prospectively; accordingly, comparative amounts for prior periods have not been restated. The reclassification of the foreign currency translation adjustment to other comprehensive income was applied retroactively with prior period restatement.

The effects of adopting these standards on the opening balance sheet were as follows:

($ millions)		**Jan 1, 2007**
Increased current portion of other long-term assets [(1)]	**$**	**193**
Decreased other long-term assets [(2)]	**$**	**(16)**
Decreased long-term debt [(3)]	**$**	**(72)**
Increased retained earnings [(4)]	**$**	**10**
Increased foreign currency translation adjustment [(5)]	**$**	**13**
Increased accumulated other comprehensive income [(6)]	**$**	**146**
Decreased current portion of future income tax asset [(7)]	**$**	**(62)**
Increased future income tax liability [(7)]	**$**	**18**

(1) Relates to the recognition of the current portion of the fair value of derivative financial instruments designated as cash flow hedges.

(2) Relates to the recognition of the long-term portion of the fair value of derivative financial instruments designated as cash flow and fair value hedges, as well as the reclassification of transaction costs and original issue discounts from deferred charges to long-term debt.

(3) Relates to the fair value impact of derivative financial instruments designated as fair value hedges, as well as the reclassification of transaction costs and original issue discounts.

(4) Relates to the impact on adoption of the measurement of ineffectiveness on derivative financial instruments designated as cash flow hedges.

(5) Relates to the retroactive restatement of foreign currency translation adjustment to accumulated other comprehensive income.

(6) Relates to the recognition of accumulated other comprehensive income arising from the measurement of effectiveness on derivative financial instruments designated as cash flow hedges.

(7) Relates to the future income tax impacts of the above noted adjustments.

Effective January 1, 2007, the Company's accounting policies for financial instruments and comprehensive income are as follows:

All derivative financial instruments are recognized at estimated fair value on the consolidated balance sheet at each balance sheet date. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. However, these 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 Company formally documents all derivative financial instruments that are designated as hedging transactions at the inception of the hedging relationship, in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated, both at inception of the hedge and on an ongoing basis.

The Company periodically enters into commodity price contracts to manage anticipated sales of crude oil and natural gas production in order to protect cash flow for capital expenditure programs. The effective portion of changes in the fair value of derivative commodity price contracts designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to risk management activities in consolidated net earnings in the same period or periods in which the crude oil or natural gas is sold. The ineffective portion of changes in the fair value of these designated contracts is immediately recognized in risk management activities in consolidated net earnings. All changes in the fair value of non-designated crude oil and natural gas commodity price contracts are recognized in risk management activities in consolidated net earnings.

The Company enters into interest rate swap contracts to manage its fixed to floating interest rate mix on certain of its 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. Changes in the fair value of interest rate swap contracts designated as fair value hedges and corresponding changes in the fair value of the hedged long-term debt are included in interest expense in consolidated net earnings. Changes in the fair value of non-designated interest rate swap contracts are included in risk management activities in consolidated net earnings.

Cross currency swap contracts are periodically used to manage currency exposure on US dollar denominated long-term debt. 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. Changes in the fair value of the foreign exchange component of cross currency swap contracts designated as cash flow hedges are included in foreign exchange in consolidated net earnings. The effective portion of changes in the fair value of the interest rate component of cross currency swap contracts designated as cash flow hedges is initially included in other comprehensive income and is reclassified to interest expense when realized, with the ineffective portion immediately recognized in risk management activities in consolidated net earnings. Changes in the fair value of non-designated cross currency swap contracts are included in risk management activities in consolidated net earnings.

Gains or losses on the termination of financial instruments that have been designated as cash flow hedges are deferred under accumulated other comprehensive income on the consolidated balance sheets and amortized into consolidated net earnings in the period in which the underlying hedged item is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized immediately in consolidated net earnings. Gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in consolidated net earnings immediately.

Embedded derivatives are derivatives that are included in a non-derivative host contract. Embedded derivatives are recorded at fair value separately from the host contract when their economic characteristics and risks are not clearly and closely related to the host contract.

Transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability and original issue discounts on long-term debt have been included in the carrying value of the financial asset or liability and are amortized to consolidated net earnings over the life of the financial instrument using the effective interest method.

RISK MANAGEMENT

($ millions)	Three Months Ended Dec 31 2007	Sep 30 2007	Dec 31 2006	Year Ended Dec 31 2007	Dec 31 2006
Realized loss (gain)					
Crude oil and NGLs financial instruments	**$ 308**	$ 102	$ 223	**$ 505**	$ 1,395
Natural gas financial instruments	**(127)**	(125)	(97)	**(343)**	(70)
	$ 181	$ (23)	$ 126	**$ 162**	$ 1,325
Unrealized loss (gain)					
Crude oil and NGLs financial instruments	**$ 770**	$ 80	$ (239)	**$ 1,244**	$ (736)
Natural gas financial instruments	**75**	(4)	8	**156**	(260)
Interest rate swaps	**-**	-	(10)	**-**	(17)
	$ 845	$ 76	$ (241)	**$ 1,400**	$ (1,013)
Total	**$ 1,026**	$ 53	$ (115)	**$ 1,562**	$ 312

The net realized losses (gains) from crude oil and NGLs and natural gas financial instruments decreased (increased) the Company's average realized prices as follows:

	Three Months Ended Dec 31 2007	Sep 30 2007	Dec 31 2006	Year Ended Dec 31 2007	Dec 31 2006
Crude oil and NGLs ($/bbl) (1)	**$ 9.99**	$ 3.30	$ 7.09	**$ 4.18**	$ 11.57
Natural gas ($/mcf) (1)	**$ (0.87)**	$ (0.83)	$ (0.65)	**$ (0.56)**	$ (0.13)

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

Complete details related to outstanding derivative financial instruments at December 31, 2007 are disclosed in note 10 to the Company's unaudited interim consolidated financial statements. As at December 31, 2006, the net unrecognized asset related to the estimated fair values of derivative financial instruments designated as hedges was $222 million.

As effective as the Company's hedges are against reference commodity prices, a substantial portion of the commodity derivative financial instruments entered into by the Company have not been formally designated as hedges for accounting purposes or do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The change in the fair value of the 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, 2007. Due to changes in the crude oil and natural gas forward pricing, and the reversal of prior period unrealized gains and losses, the Company recorded a net unrealized loss of $1,400 million ($977 million after-tax) on its commodity risk management activities for the year ended December 31, 2007, including an $845 million ($593 million after-tax) unrealized loss for the three months ended December 31, 2007 (September 30, 2007 – unrealized loss of $76 million, $57 million after-tax; December 31, 2006 - unrealized gain of $241 million, $166 million after-tax).

FOREIGN EXCHANGE

($ millions)	Three Months Ended Dec 31 2007	Sep 30 2007	Dec 31 2006	Year Ended Dec 31 2007	Dec 31 2006
Net realized foreign exchange loss (gain)	**$ -**	$ 22	$ (20)	**$ 53**	$ (12)
Net unrealized foreign exchange (gain) loss (1)	**(47)**	(195)	171	**(524)**	134
	$ (47)	$ (173)	$ 151	**$ (471)**	$ 122

(1) Amounts are reported net of the hedging effect of cross currency interest rate swaps 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 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, while production expenses in Offshore West Africa are subject to foreign currency fluctuations due to changes in the exchange rate of the Canadian dollar 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 gain for the three months and year ended December 31, 2007 was primarily related to the strengthening of the Canadian dollar in relation to the US dollar with respect to the US dollar debt. The net unrealized foreign exchange gain for the three months ended December 31, 2007 was also impacted by the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars. Included in the net unrealized gain for the year ended December 31, 2007 was an unrealized loss of $350 million (nine months ended September 30, 2007 – unrealized loss of $335 million) related to the impact of the cross currency interest rate swaps. The net realized foreign exchange gain for the year ended December 31, 2007 was primarily due to the result of foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The Canadian dollar ended the fourth quarter above parity, at US$1.0120 compared to US$1.0037 at September 30, 2007 (December 31, 2006 - US$0.8581).

During the first quarter of 2007, the Company de-designated the portion of the US dollar denominated debt previously hedged against its net investment in US dollar based self-sustaining foreign operations. Accordingly, all foreign exchange (gains) losses arising each period on US dollar denominated long-term debt are now recognized in the consolidated statement of earnings.

TAXES

($ millions, except income tax rates)	Three Months Ended **Dec 31 2007**	Sep 30 2007	Dec 31 2006	Year Ended **Dec 31 2007**	Dec 31 2006
Taxes other than income tax					
Current	**$ 16**	$ 30	$ 44	**$ 121**	$ 219
Deferred	**17**	10	(3)	**44**	37
	$ 33	$ 40	$ 41	**$ 165**	$ 256
Current income tax					
North America	**$ 31**	$ 28	$ 51	**$ 96**	$ 143
North Sea	**65**	56	30	**210**	30
Offshore West Africa	**27**	21	14	**74**	49
	123	105	95	**380**	222
Future income tax (recovery) expense	**(847)**	175	135	**(456)**	652
	(724)	280	230	**(76)**	874
Income tax rate and other legislative changes (1) (2) (3)	**793**	-	-	**864**	395
Total income tax expense	**$ 69**	$ 280	$ 230	**$ 788**	$ 1,269
Effective income tax rate before non-recurring benefits	**93.2%**	28.6%	42.4%	**31.1%**	37.3%

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

(2) 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.

(3) Includes the effect of the following:
- *a one time expense of $110 million related to the increased supplementary charge on oil and gas profits in the UK North Sea, substantively enacted during the first quarter of 2006.*
- *a one time recovery of $438 million due to Canadian Federal, Alberta and Saskatchewan tax rate reductions enacted during the second quarter of 2006.*
- *a one time recovery of $67 million due to Côte d'Ivoire corporate income tax rate reductions enacted during the third quarter of 2006.*

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 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 a future period. North America current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary depending upon the nature, timing and amount of capital expenditures incurred in Canada in any particular year. In particular, current taxes in a specific year are sensitive to the timing of when the Horizon Project capital expenditures are deductible for Canadian income tax purposes.

During the year ended December 31, 2007, the Company's consolidated effective income tax rate was reduced primarily due to income tax rate reductions enacted in Canada during the second and fourth quarters of 2007, the effects of the non-taxable portion of unrealized foreign exchange gains on US dollar debt, net of unrealized losses on cross currency swaps, and adjustments to future tax expense in Canada related to the final phase-in of deductibility of crown royalties and the elimination of the resource allowance deduction in 2007.

CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Dec 31 2007	Sep 30 2007	Dec 31 2006	Year Ended Dec 31 2007	Dec 31 2006
Expenditures on property, plant and equipment					
Net property (dispositions) acquisitions	**$ (107)**	$ 7	$ 4,720	**$ (39)**	$ 4,733
Land acquisition and retention	**15**	29	28	**95**	210
Seismic evaluations	**17**	23	17	**124**	130
Well drilling, completion and equipping	**341**	299	462	**1,642**	2,340
Production and related facilities	**390**	238	311	**1,205**	1,314
Total net reserve replacement expenditures	**656**	596	5,538	**3,027**	8,727
Horizon Project:					
Phase 1 construction costs	**691**	671	745	**2,740**	2,768
Phases 2/3 costs	**33**	28	54	**124**	79
Capitalized interest, stock-based compensation and other	**108**	120	134	**437**	338
Total Horizon Project	**832**	819	933	**3,301**	3,185
Midstream	**2**	2	1	**6**	12
Abandonments [2]	**16**	22	19	**71**	75
Head office	**8**	3	6	**20**	26
Total net capital expenditures	**$ 1,514**	$ 1,442	$ 6,497	**$ 6,425**	$ 12,025
By segment					
North America	**$ 570**	$ 441	$ 5,296	**$ 2,428**	$ 7,936
North Sea	**44**	121	211	**439**	646
Offshore West Africa	**43**	34	30	**159**	134
Other	**(1)**	-	1	**1**	11
Horizon Project	**832**	819	933	**3,301**	3,185
Midstream	**2**	2	1	**6**	12
Abandonments [2]	**16**	22	19	**71**	75
Head office	**8**	3	6	**20**	26
Total	**$ 1,514**	$ 1,442	$ 6,497	**$ 6,425**	$ 12,025

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

(2) 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, 2007 were $6,425 million compared to $12,025 million for the year ended December 31, 2006. Excluding the ACC acquisition, net capital expenditures were $7,270 million for 2006. Capital expenditures in 2007 reflected the continued progress on the Company's larger, future growth projects, most notably the Horizon Project, as well as continued industry-wide inflationary pressures, offset by the effects of an overall strategic reduction in the North America natural gas drilling program.

For the year ended December 31, 2007, the Company drilled a total of 1,322 net wells consisting of 383 natural gas wells, 592 crude oil wells, 254 stratigraphic test and service wells and 93 wells that were dry. This compared to 1,738 net wells drilled for the year ended December 31, 2006. The Company achieved an overall success rate of 91% for the year ended December 31, 2007, excluding stratigraphic test and service wells, consistent with the year ended December 31, 2006**.**

Net capital expenditures for the fourth quarter of 2007 were $1,514 million compared to $6,497 million for the fourth quarter of 2006 and $1,442 million for the prior quarter. Excluding the ACC acquisition, net capital expenditures were $1,742 million for the fourth quarter of 2006. Fourth quarter 2007 capital expenditures decreased from the comparable period in 2006 due to the Company's strategic reduction in natural gas drilling activity, and increased slightly from the third quarter of 2007 due to normal drilling seasonality.

For the fourth quarter of 2007, the Company drilled a total of 271 net wells consisting of 80 natural gas wells, 169 crude oil wells, 6 stratigraphic test and service wells and 16 wells that were dry. This compared to 331 net wells for the fourth quarter of 2006 and 268 net wells for the prior quarter. The Company achieved an overall success rate of 94% for the fourth quarter of 2007, excluding stratigraphic test and service wells, compared to 89% for the fourth quarter of 2006 and 95% for the third quarter of 2007**.**

North America

North America, including the Horizon Project, accounted for approximately 91% of the total capital expenditures for the year ended December 31, 2007 compared to approximately 93% for the year ended December 31, 2006.

During the year ended December 31, 2007, the Company targeted 450 net natural gas wells, including 58 wells in Northeast British Columbia, 133 wells in the Northern Plains region, 110 wells in Northwest Alberta, and 149 wells in the Southern Plains region. The Company also targeted 610 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 362 heavy crude oil wells, 127 Pelican Lake crude oil wells, 55 thermal crude oil wells and 6 light crude oil wells were drilled. Another 60 wells targeting light crude oil were drilled outside the Northern Plains region.

Due to significant changes in relative commodity prices between crude oil and natural gas, the Company continues 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, natural gas drilling activities were reduced to manage overall capital spending. Deferred natural gas well locations have been retained in the Company's prospect inventory. Drilling on ACC acquired lands was optimized as part of the overall capital program.

In November of 2005, the Company announced a phased expansion of its In-Situ Oil Sands Assets. As part of the development, the Company is continuing to develop its Primrose thermal projects. During 2007, the Company drilled 135 stratigraphic test wells and observation wells, 2 water source wells and 55 thermal oil wells. Overall Primrose thermal production for each of the years ended December 31, 2007 and 2006 was approximately 64,000 bbl/d.

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, is anticipated to add approximately 40,000 bbl/d when complete. The Primrose East Expansion received Board of Directors' sanction in 2006 and the Alberta Energy and Utilities Board regulatory approval in the first quarter of 2007. Drilling and construction are currently underway, and production is targeted to commence in 2009.

The next phase of the Company's In-Situ Oil Sands Assets expansion is the Kirby project located 120 kilometers north of the existing Primrose facilities. The Kirby project is anticipated to add approximately 45,000 bbl/d of production growth. During September 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.

Development of new pads and secondary recovery conversion projects at Pelican Lake continued as expected throughout the fourth quarter of 2007. Drilling consisted of 18 horizontal wells in the fourth quarter and 125 horizontal wells for the year ended December 31, 2007. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 36,000 bbl/d for the fourth quarter of 2007 compared to 29,000 bbl/d for the fourth quarter of 2006.

Due to growing concerns relating to increased environmental costs for upgraders located in Canada, inflationary capital cost pressures and narrowing heavy oil differentials in North America, the Company has, at this point in time, deferred the Design Basis Memorandum and Engineering Design Specification of the Canadian Natural Upgrader, outside of the Horizon Project, pending clarification on the cost of future environmental legislation and a more stable cost environment.

For the first quarter of 2008, the Company's overall drilling activity in North America is expected to be comprised of 173 natural gas wells and 175 crude oil wells excluding stratigraphic and service wells.

Horizon Project

Work progress on the Horizon Project was 90% complete at the end of the fourth quarter. First production continues to be targeted to commence in the third quarter of 2008. The project status as at December 31, 2007 was as follows:

- Overall detailed engineering 98.5% complete and substantially complete in most areas;
- Overall procurement 99% complete with over $5.6 billion in purchase orders and contracts awarded;
- Commenced receipt and site assembly of Mine Operations equipment (Shovels and Heavy Haul Trucks);
- Overall construction progress 85% complete;
- Mine overburden removal approximately 72% complete and 0.6 million bank cubic meters ahead of schedule;
- Main Control Room Distributed Control Systems equipment powered and tested;
- Commissioned 260kV Transmission Line and turned over to operations;
- Commissioned Raw Water Pumphouse and turned over to operations;
- Completed reformer erection in Hydrogen Plant;
- Completed installation and pre-commissioning of CPI Separator Building;
- Completed the closure of Dyke 10 (external tailings pond) in Mining;
- Completed erection of Crushing Plants and conveyors in Ore Preparation Area;
- Completed Primary Separation Cells in Extraction; and
- Completed construction of Main Laboratory.

Major activities for the first quarter of 2008 include:

- Mechanically complete Extraction Plant;
- Mechanically complete Froth Treatment Plant;
- Mechanically complete Amine Plant;
- Complete Auxiliary Boiler installation in Cogeneration; and
- Complete Piping in Heat Integration.

The Company has budgeted construction costs of approximately $1.7 billion to $1.9 billion for 2008 related to the planned completion of Phase 1 of the Horizon Project.

North Sea

In the fourth quarter of 2007, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During the quarter, no wells were drilled, with 1.6 net wells drilling at the end of the quarter.

At Ninian, the Company continued with its planned investment in its long-term facilities and infrastructure strategy, as well as completing workover activity to address water injection performance issues. Upon completion of this activity, the drilling crew was mobilized to the Murchison Platform to commence the first of 2 wells planned for 2008.

In December 2007, the Company completed the sale of its entire working interest in the B-Block, comprising the Balmoral, Stirling, and Glamis Fields.

Offshore West Africa

During the fourth quarter of 2007, 1.2 net wells were drilled with 0.6 net wells drilling at the end of the quarter.

First crude oil from West Espoir commenced production in mid 2006 with 1 additional production well and 1 additional injector well added during the fourth quarter of 2007. West Espoir development drilling was completed in early 2008, on budget and on schedule.

At the 90% owned and operated Olowi Field in offshore Gabon, all major construction contracts have been awarded and construction activity on the wellhead towers and the floating production storage and offtake vessel (“FPSO”) are ongoing. The project is on schedule with drilling targeted to commence in the second quarter of 2008 and first crude oil targeted in late 2008. Olowi production is targeted to plateau at approximately 20,000 bbl/d net to the Company.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Dec 31 2007**	Sep 30 2007	Dec 31 2006
Working capital deficit (1)	**$ 1,382**	$ 824	$ 832
Long-term debt (2)	**$ 10,940**	$ 10,686	$ 11,043
Shareholders’ equity			
Share capital	**$ 2,674**	$ 2,663	$ 2,562
Retained earnings	**10,575**	9,824	8,141
Accumulated other comprehensive income (loss)	**72**	85	(13)
Total	**$ 13,321**	$ 12,572	$ 10,690
Debt to book capitalization (2) (3)	**45%**	46%	51%
Debt to market capitalization (2) (4)	**22%**	21%	25%
After tax return on average common shareholders’ equity (5)	**22%**	19%	27%
After tax return on average capital employed (2) (6)	**12%**	11%	17%

(1) Calculated as current assets less current liabilities.

(2) Long-term debt at December 31, 2007 is stated at its carrying value, net of fair value adjustments, original issue discounts and transactions costs. Amounts for periods prior to January 1, 2007 were not adjusted for these items.

(3) Calculated as long-term debt; divided by the book value of common shareholders’ equity plus long-term debt.

(4) Calculated as long-term debt; divided by the market value of common shareholders’ equity plus long-term debt.

(5) Calculated as net earnings for the twelve month trailing period; as a percentage of average common shareholders’ equity for the period.

(6) 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 long-term debt for the period, including $7,001 million in average capital employed related to the Horizon Project (2006 - $3,760 million; 2005 - $1,421 million).

The Company's capital resources at December 31, 2007 consisted primarily of cash flow from operations, available 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, 2006 annual MD&A**.** The Company's ability to renew existing 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. Management believes internally generated cash flows supported by the implementation of the Company's hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, the Company's existing credit facilities and the Company's ability to raise new debt on commercially acceptable terms, will be sufficient to sustain its operations and support its growth strategy. 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. The Company does not have any direct exposure to asset-backed commercial paper.

At December 31, 2007, the Company had undrawn bank lines of credit of $1,442 million. Details related to the Company's long-term debt at December 31, 2007 are disclosed in note 4 to the Company's unaudited interim consolidated financial statements. Subsequent to December 31, 2007, the Company issued an aggregate US$1,200 million of unsecured notes. Proceeds from the securities issued were used to repay the Company's bankers' acceptances.

At December 31, 2007, the Company's working capital deficit was $1,382 million and included the current portion of the stock-based compensation liability of $390 million and the current portion of the net mark-to-market liability for risk management derivative financial instruments of $1,227 million. 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. 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, 2007.

The Company believes it has the necessary financial capacity to complete the Horizon Project, while at the same time not compromising conventional crude oil and natural gas growth opportunities. The financing of Phase 1 of the Horizon Project development is guided by the competing principles of retaining as much direct ownership interest as possible while maintaining a strong balance sheet.

Long-term debt was $10,940 million at December 31, 2007, resulting in a debt to book capitalization level of 45% (September 30, 2007 – 46%; December 31, 2006 – 51%). While this ratio is at the high end of the 35% to 45% range targeted by management, the Company remains committed to maintaining a strong balance sheet and flexible capital structure, and expects its debt to book capitalization ratio to be near the midpoint of the range in late 2008. While the Company believes that it has the balance sheet strength and flexibility to complete Phase 1 of the Horizon Project, as well as its other planned capital expenditure programs, the Company has hedged a significant portion of its crude oil and natural gas production for 2008 at prices that protect investment returns. 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 price markets and supports the Company's cash flow for its capital expenditures throughout the Horizon Project construction period. This program allows for the hedging of up to 75% of the near 12 months budgeted production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. In accordance with the policy, approximately 65% of expected crude oil volumes are hedged for 2008 and approximately 53% of expected natural gas volumes are hedged for the first quarter of 2008. Subsequent to December 31, 2007, the Company hedged 25,000 bbl/d of crude oil volumes for 2009 using WTI collars with a US$70.00 floor.

The Company has the following commodity related net financial derivatives outstanding as at December 31, 2007:

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Crude oil price collars [(1)]	Jan 2008	–	Mar 2008	50,000 bbl/d	US$60.00	–	US$80.06	WTI
	Jan 2008	–	Jun 2008	25,000 bbl/d	US$60.00	–	US$80.44	WTI
	Apr 2008	–	Sep 2008	25,000 bbl/d	US$60.00	–	US$80.46	WTI
	Jul 2008	–	Sep 2008	25,000 bbl/d	US$70.00	–	US$123.75	WTI
	Oct 2008	–	Dec 2008	25,000 bbl/d	US$70.00	–	US$112.63	WTI
	Jan 2008	–	Dec 2008	20,000 bbl/d	US$50.00	–	US$65.53	Mayan Heavy
	Jan 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$75.22	WTI
	Jan 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.05	WTI
	Jan 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.98	WTI
Crude oil puts	Jan 2008	–	Dec 2008	50,000 bbl/d			US$55.00	WTI

(1) Subsequent to December 31, 2007, the Company entered into 25,000 bbl/d of US$70.00 – US$111.56 WTI collars for the period January to December 2009.

Natural gas								
AECO price collars	Jan 2008	–	Mar 2008	400,000 GJ/d	C$7.00	–	C$14.08	AECO
	Jan 2008	–	Mar 2008	500,000 GJ/d	C$7.50	–	C$10.81	AECO

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

Long-term debt

As at December 31, 2007, the Company had in place unsecured bank credit facilities of $6,209 million, comprised of:

- a $100 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.

During the second quarter of 2007, one of the revolving syndicated credit facilities was increased from $1,825 million to $2,230 million and a $500 million demand credit facility was terminated. The revolving syndicated credit facilities were extended and now mature June 2012. Both 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.

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 in October 2009. In March 2007, $1,500 million was repaid, reducing the facility to $2,350 million.

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $345 million, including $300 million related to the Horizon Project, were outstanding at December 31, 2007.

Medium-term notes

In December 2007, the Company issued $400 million of unsecured notes maturing December 2010, bearing interest at 5.50%. 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 $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.

During the first quarter of 2007, $125 million of 7.40% unsecured debentures due March 1, 2007 were repaid.

Senior unsecured notes

During the second quarter of 2007, US$31 million of the senior unsecured notes were repaid.

US dollar debt securities

In March 2007, the Company issued US$2,200 million of unsecured notes, comprised of US$1,100 million of unsecured notes maturing May 2017 and US$1,100 million of unsecured notes maturing March 2038, bearing interest at 5.70% and 6.25%, respectively. Concurrently, the Company entered into cross currency interest rate swaps to fix the Canadian dollar interest and principal repayment amounts on the entire US$1,100 million of unsecured notes due May 2017 at 5.10% and C$1,287 million. The Company also entered into a cross currency interest rate swap to fix the Canadian dollar interest and principal repayment amounts on US$550 million of unsecured notes due March 2038 at 5.76% and C$644 million. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

During the first quarter of 2007, the Company de-designated the portion of its US dollar denominated debt previously hedged against its net investment in US dollar based self-sustaining foreign operations. Accordingly, all foreign exchange (gains) losses arising each period on U.S. dollar denominated long-term debt are now recognized in the consolidated statement of earnings.

In September 2007, the Company filed a base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States until October 2009.

Subsequent to December 31, 2007, the Company issued US$1,200 million of unsecured notes under this 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. If issued, these securities will bear interest as determined at the date of issuance.

Share capital

As at December 31, 2007, there were 539,729,000 common shares outstanding and 30,649,000 stock options outstanding. As at February 26, 2008, the Company had 540,252,000 common shares outstanding and 29,173,000 stock options outstanding.

During 2007, the Company did not purchase any common shares for cancellation pursuant to the Normal Course Issuer Bid previously filed for the 12-month period beginning January 24, 2007 and ending January 23, 2008. The Company has decided not to renew the Normal Course Issuer Bid until subsequent to the completion of Phase 1 of the Horizon Project.

In February 2008, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.40 per common share for 2008. The increase represents a 18% increase from 2007, recognizes the stability of the Company's cash flow, and provides a return to Shareholders. This is the eighth consecutive year in which the Company has paid dividends and the seventh consecutive year of an increase in the distribution paid to its Shareholders. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change. In March 2007, an increase in the annual dividend paid by the Company was approved to $0.34 per common share for 2007. The increase represented a 13% increase from 2006.

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 debt repayments, operating leases relating to offshore FPSOs, drilling rigs and office space, and firm commitments for gathering, processing and transmission services, as well as expenditures relating to asset retirement obligations. As at December 31, 2007, no entities were consolidated under the Canadian Institute of Chartered Accountants Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at December 31, 2007:

($ millions)	2008	2009	2010	2011	2012	Thereafter
Product transportation and pipeline	$ 232	$ 151	$ 137	$ 109	$ 91	$ 972
Offshore equipment operating lease (1)	$ 114	$ 129	$ 113	$ 111	$ 90	$ 387
Offshore drilling (2) (3)	$ 267	$ 185	$ 39	$ -	$ -	$ -
Asset retirement obligations (4)	$ 33	$ 4	$ 5	$ 4	$ 4	$ 4,376
Long-term debt (5)	$ 39	$ 2,361	$ 400	$ 395	$ 346	$ 5,098
Interest expense (6)	$ 612	$ 590	$ 487	$ 465	$ 374	$ 4,338
Office lease	$ 26	$ 28	$ 28	$ 22	$ 3	$ -
Electricity and other	$ 166	$ 173	$ 25	$ 4	$ -	$ -

(1) Offshore equipment operating leases are primarily comprised of obligations related to FPSOs. During 2006, the Company entered into an agreement to lease an additional FPSO commencing in 2008, in connection with the planned offshore development in Gabon, Offshore West Africa. During the initial term, the total annual payments for the Gabon FPSO are estimated to be US$50 million.

(2) During 2007, the Company entered into a one-year agreement for offshore drilling services related to the Baobab Field in Côte d'Ivoire, Offshore West Africa. The agreement is scheduled to commence in 2008, subject to rig availability. Estimated total payments of US$100 million, after joint venture recoveries, have been included in this table for the period 2008 - 2009.

(3) During 2007, the Company awarded contracts for a drilling rig and for the construction of wellhead towers in connection with the planned offshore development in Gabon, Offshore West Africa. Estimated total payments of US$393 million have been included in this table for the period 2008 – 2010.

(4) 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 2008 – 2012 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(5) 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 $2,366 million of revolving bank credit facilities due to the extendable nature of the facilities.

(6) 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 of December 31, 2007.

In addition to the amounts disclosed above, the Company has budgeted construction costs of approximately $1.7 billion to $1.9 billion for 2008 related to the planned completion of Phase 1 of the Horizon Project.

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 could differ from those estimates. A comprehensive discussion of the Company's significant accounting policies is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2006.

For the impact of new accounting standards related to financial instruments and comprehensive income, please refer to Risk Management Activities on page 38 of this MD&A and note 2 of the unaudited interim consolidated financial statements as at December 31, 2007.

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 2007, excluding mark-to-market gains (losses) on risk management activities, and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only; all other variables are 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	$ 96	$ 0.18	$ 70	$ 0.13
Including financial derivatives	$ 21	$ 0.04	$ 17	$ 0.03
Natural gas – AECO C$0.10/mcf [1]				
Excluding financial derivatives	$ 41	$ 0.08	$ 29	$ 0.05
Including financial derivatives	$ 33	$ 0.06	$ 23	$ 0.04
Volume changes				
Crude oil – 10,000 bbl/d	$ 132	$ 0.25	$ 70	$ 0.13
Natural gas – 10 mmcf/d	$ 16	$ 0.03	$ 6	$ 0.01
Foreign currency rate change				
$0.01 change in US$ [1]				
Including financial derivatives	$ 73 - 74	$ 0.13 – 0.14	$ 31 - 32	$ 0.06
Interest rate change - 1%	$ 38	$ 0.07	$ 38	$ 0.07

(1) For details of outstanding financial instruments in place, refer to note 10 of the Company's unaudited interim consolidated financial statements.

OTHER OPERATING HIGHLIGHTS

NETBACK ANALYSIS

($/boe) [1]	Three Months Ended Dec 31 2007	Three Months Ended Sep 30 2007	Three Months Ended Dec 31 2006	Year Ended Dec 31 2007	Year Ended Dec 31 2006
Sales price [2]	**$ 49.23**	$ 47.96	$ 43.91	**$ 49.05**	$ 47.92
Royalties	**6.21**	6.07	5.62	**6.26**	5.89
Production expense [3]	**8.85**	9.62	9.16	**9.75**	9.14
Netback	**34.17**	32.27	29.13	**33.04**	32.89
Midstream contribution [3]	**(0.24)**	(0.26)	(0.22)	**(0.23)**	(0.23)
Administration	**0.76**	0.94	1.01	**0.93**	0.85
Interest, net	**0.92**	1.15	1.08	**1.24**	0.66
Realized risk management loss (gain)	**3.27**	(0.41)	2.25	**0.73**	6.27
Realized foreign exchange (gain) loss	**-**	0.38	(0.34)	**0.24**	(0.06)
Taxes other than income tax - current	**0.30**	0.54	0.78	**0.54**	1.04
Current income tax - North America	**0.56**	0.49	0.91	**0.43**	0.68
Current income tax - North Sea	**1.18**	0.99	0.54	**0.95**	0.14
Current income tax - Offshore West Africa	**0.50**	0.37	0.24	**0.33**	0.23
Cash flow	**$ 26.92**	$ 28.08	$ 22.88	**$ 27.88**	$ 23.31

(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.

(3) Excluding intersegment elimination.

FINANCIAL STATEMENTS

Consolidated balance sheets

(millions of Canadian dollars, unaudited)	**Dec 31 2007**	Dec 31 2006
ASSETS		
Current assets		
Cash and cash equivalents	**$ 21**	$ 23
Accounts receivable and other	**1,662**	1,947
Future income tax	**480**	163
Current portion of other long-term assets (note 3)	**18**	106
	2,181	2,239
Property, plant and equipment (note 12)	**33,902**	30,767
Other long-term assets (note 3)	**31**	154
	$ 36,114	$ 33,160
LIABILITIES		
Current liabilities		
Accounts payable	**$ 379**	$ 842
Accrued liabilities	**1,567**	1,618
Current portion of other long-term liabilities (note 5)	**1,617**	611
	3,563	3,071
Long-term debt (note 4)	**10,940**	11,043
Other long-term liabilities (note 5)	**1,561**	1,393
Future income tax	**6,729**	6,963
	22,793	22,470
SHAREHOLDERS' EQUITY		
Share capital (note 7)	**2,674**	2,562
Retained earnings	**10,575**	8,141
Accumulated other comprehensive income (loss) (note 8)	**72**	(13)
	13,321	10,690
	$ 36,114	$ 33,160

Commitments (note 11)

Consolidated statements of earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended **Dec 31 2007**	 Dec 31 2006	Year Ended **Dec 31 2007**	 Dec 31 2006
Revenue	**$ 3,200**	$ 2,826	**$ 12,543**	$ 11,643
Less: royalties	**(343)**	(317)	**(1,391)**	(1,245)
Revenue, net of royalties	**2,857**	2,509	**11,152**	10,398
Expenses				
Production	**491**	519	**2,184**	1,949
Transportation and blending	**467**	333	**1,570**	1,443
Depletion, depreciation and amortization	**719**	724	**2,863**	2,391
Asset retirement obligation accretion (note 5)	**17**	18	**70**	68
Administration	**42**	57	**208**	180
Stock-based compensation (recovery) expense (note 5)	**(16)**	176	**193**	139
Interest, net	**51**	62	**276**	140
Risk management activities (note 10)	**1,026**	(115)	**1,562**	312
Foreign exchange (gain) loss	**(47)**	151	**(471)**	122
	2,750	1,925	**8,455**	6,744
Earnings before taxes	**107**	584	**2,697**	3,654
Taxes other than income tax	**33**	41	**165**	256
Current income tax expense (note 6)	**123**	95	**380**	222
Future income tax (recovery) expense (note 6)	**(847)**	135	**(456)**	652
Net earnings	**$ 798**	$ 313	**$ 2,608**	$ 2,524
Net earnings per common share (note 9)				
Basic and diluted	**$ 1.48**	$ 0.58	**$ 4.84**	$ 4.70

Consolidated statements of shareholders' equity

(millions of Canadian dollars, unaudited)	Year Ended Dec 31 2007	Dec 31 2006
Share capital		
Balance – beginning of year	**$ 2,562**	$ 2,442
Issued upon exercise of stock options	**21**	21
Previously recognized liability on stock options exercised for common shares	**91**	101
Purchase of common shares under Normal Course Issuer Bid	**-**	(2)
Balance – end of year	**2,674**	2,562
Retained earnings		
Balance – beginning of year, as originally reported	**8,141**	5,804
Transition adjustment on adoption of financial instruments standards (note 2)	**10**	-
Balance – beginning of year, as restated	**8,151**	5,804
Net earnings	**2,608**	2,524
Dividends on common shares (note 7)	**(184)**	(161)
Purchase of common shares under Normal Course Issuer Bid	**-**	(26)
Balance – end of year	**10,575**	8,141
Accumulated other comprehensive income (loss) (note 2)		
Balance – beginning of year	**(13)**	(9)
Transition adjustment on adoption of financial instruments standards	**159**	-
Balance – beginning of year, after effect of transition adjustment	**146**	(9)
Other comprehensive loss, net of taxes	**(74)**	(4)
Balance – end of year	**72**	(13)
Shareholders' equity	**$ 13,321**	$ 10,690

Consolidated statements of comprehensive income

(millions of Canadian dollars, unaudited)	Three Months Ended Dec 31 2007	Three Months Ended Dec 31 2006	Year Ended Dec 31 2007	Year Ended Dec 31 2006
Net earnings	**$ 798**	$ 313	**$ 2,608**	$ 2,524
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income during the period (net of taxes of $3 million – three months ended; $6 million – year ended)	**32**	-	**38**	-
Reclassification to net earnings (net of taxes of $21 million – three months ended; $45 million – year ended)	**(45)**	-	**(96)**	-
	(13)	-	**(58)**	-
Foreign currency translation adjustment				
Translation of net investment	**-**	2	**(16)**	(4)
Hedge of net investment, net of tax	**-**	(3)	**-**	-
	-	(1)	**(16)**	(4)
Other comprehensive loss, net of taxes	**(13)**	(1)	**(74)**	(4)
Comprehensive income	**$ 785**	$ 312	**$ 2,534**	$ 2,520

Consolidated statements of cash flows

(millions of Canadian dollars, unaudited)	Three Months Ended **Dec 31 2007**	 Dec 31 2006	Year Ended **Dec 31 2007**	 Dec 31 2006
Operating activities				
Net earnings	**$ 798**	$ 313	**$ 2,608**	$ 2,524
Non-cash items				
Depletion, depreciation and amortization	**719**	724	**2,863**	2,391
Asset retirement obligation accretion	**17**	18	**70**	68
Stock-based compensation (recovery) expense	**(16)**	176	**193**	139
Unrealized risk management activities	**845**	(241)	**1,400**	(1,013)
Unrealized foreign exchange (gain) loss	**(47)**	171	**(524)**	134
Deferred petroleum revenue tax expense (recovery)	**17**	(3)	**44**	37
Future income tax (recovery) expense	**(847)**	135	**(456)**	652
Deferred charges and other	**31**	6	**38**	(2)
Abandonment expenditures	**(16)**	(19)	**(71)**	(75)
Net change in non-cash working capital	**(264)**	(317)	**(346)**	(679)
	1,237	963	**5,819**	4,176
Financing activities				
(Repayment) issue of bank credit facilities, net	**(128)**	5,384	**(1,925)**	6,499
Issue of medium-term notes	**398**	-	**273**	400
Repayment of senior unsecured notes	**-**	-	**(33)**	-
Issue of US dollar debt securities	**-**	-	**2,553**	788
Issue of common shares on exercise of stock options	**2**	4	**21**	21
Dividends on common shares	**(46)**	(40)	**(178)**	(153)
Purchase of common shares	**-**	-	**-**	(28)
Net change in non-cash working capital	**2**	29	**8**	37
	228	5,377	**719**	7,564
Investing activities				
Expenditures on property, plant and equipment	**(1,603)**	(1,791)	**(6,464)**	(7,266)
Net proceeds on sale of property, plant and equipment	**105**	68	**110**	71
Net expenditures on property, plant and equipment	**(1,498)**	(1,723)	**(6,354)**	(7,195)
Acquisition of Anadarko Canada Corporation	**-**	(4,641)	**-**	(4,641)
Net change in non-cash working capital	**33**	35	**(186)**	101
	(1,465)	(6,329)	**(6,540)**	(11,735)
Increase (decrease) in cash and cash equivalents	**-**	11	**(2)**	5
Cash and cash equivalents – beginning of period	**21**	12	**23**	18
Cash and cash equivalents – end of period	**$ 21**	$ 23	**$ 21**	$ 23
Interest paid	**$ 153**	$ 83	**$ 556**	$ 262
Taxes paid				
Taxes other than income tax	**$ 13**	$ 52	**$ 116**	$ 291
Current income tax	**$ 145**	$ 108	**$ 302**	$ 412

Notes to the consolidated financial statements (tabular amounts in millions of Canadian dollars, 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, 2006, 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, 2006.

2. CHANGE IN ACCOUNTING POLICY

Financial Instruments and Comprehensive Income

Effective January 1, 2007, the Company adopted the following new accounting standards issued by the Canadian Institute of Chartered Accountants relating to the accounting for and disclosure of financial instruments and comprehensive income:

- Section 1530 – "Comprehensive Income" introduces the concept of comprehensive income to Canadian GAAP. Comprehensive income is the change in equity (net assets) of the Company during a reporting period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except transactions with owners. The foreign currency translation adjustment, which was previously a separate component of shareholders' equity, is now recorded as part of accumulated other comprehensive income.

- Section 3251 – "Equity" replaces Section 3250 – "Surplus" and establishes standards for the presentation of equity and changes in equity during a reporting period.

- Section 3855 – "Financial Instruments – Recognition and Measurement" prescribes when a financial asset, financial liability, or non-financial derivative should be recognized on the balance sheet as well as its measurement amount.

- Section 3865 – "Hedges" replaces Accounting Guideline 13 – "Hedging Relationships" and EIC 128 – "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments" and specifies how hedge accounting is to be applied and what disclosures are necessary when hedge accounting is applied.

Adoption of these standards required the Company to record all of its derivative financial instruments on the balance sheet at estimated fair value as at January 1, 2007, including those designated as hedges. Designated hedges, other than cross currency swaps, were previously not recognized on the balance sheet but were disclosed in the notes to the financial statements. The adjustment to recognize all designated hedges on the balance sheet was recorded as an adjustment to the opening balance of retained earnings or accumulated other comprehensive income, as appropriate.

With the exception of the foreign currency translation adjustment, these standards were adopted prospectively; accordingly, comparative amounts for prior periods have not been restated. The reclassification of the foreign currency translation adjustment to other comprehensive income was applied retroactively with prior period restatement.

Effective January 1, 2007, the Company's accounting policies for financial instruments and comprehensive income are as follows:

Risk Management Activities

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

All derivative financial instruments are recognized at estimated fair value on the consolidated balance sheet at each balance sheet date. The estimated fair value of derivative instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. However, these 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 Company formally documents all derivative financial instruments that are designated as hedging transactions at the inception of the hedging relationship, in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated, both at inception of the hedge and on an ongoing basis.

The Company periodically enters into commodity price contracts to manage anticipated sales of crude oil and natural gas production in order to protect cash flow for capital expenditure programs. The effective portion of changes in the fair value of derivative commodity price contracts designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to risk management activities in consolidated net earnings in the same period or periods in which the crude oil or natural gas is sold. The ineffective portion of changes in the fair value of these designated contracts is immediately recognized in risk management activities in consolidated net earnings. All changes in the fair value of non-designated crude oil and natural gas commodity price contracts are recognized in risk management activities in consolidated net earnings.

The Company enters into interest rate swap contracts to manage its fixed to floating interest rate mix on certain of its 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. Changes in the fair value of interest rate swap contracts designated as fair value hedges and corresponding changes in the fair value of the hedged long-term debt are included in interest expense in consolidated net earnings. Changes in the fair value of non-designated interest rate swap contracts are included in risk management activities in consolidated net earnings.

Cross currency swap contracts are periodically used to manage currency exposure on US dollar denominated long-term debt. 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. Changes in the fair value of the foreign exchange component of cross currency swap contracts designated as cash flow hedges are included in foreign exchange in consolidated net earnings. The effective portion of changes in the fair value of the interest rate component of cross currency swap contracts designated as cash flow hedges is initially included in other comprehensive income and is reclassified to interest expense when realized, with the ineffective portion recognized in risk management activities in consolidated net earnings. Changes in the fair value of non-designated cross currency swap contracts are included in risk management activities in consolidated net earnings.

Gains or losses on the termination of financial instruments that have been designated as cash flow hedges are deferred under accumulated other comprehensive income on the consolidated balance sheets and amortized into consolidated net earnings in the period in which the underlying hedged item is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized immediately in consolidated net earnings. Gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in consolidated net earnings immediately.

Embedded derivatives are derivatives that are included in a non-derivative host contract. Embedded derivatives are recorded at fair value separately from the host contract when their economic characteristics and risks are not clearly and closely related to the host contract.

Transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability and original issue discounts on long-term debt have been included in the carrying value of the related financial asset or liability and are amortized to consolidated net earnings over the life of the financial instrument using the effective interest method.

Comprehensive Income

Comprehensive income is comprised of the Company's net earnings and other comprehensive income. Other comprehensive income includes the effective portion of changes in the fair value of derivative financial instruments designated as cash flow hedges and foreign currency translation gains and losses on the net investment in self-sustaining foreign operations. Other comprehensive income is shown net of related income taxes.

The effects of adopting these standards on the opening balance sheet were as follows:

		Jan 1, 2007
Increased current portion of other long-term assets (1)	$	193
Decreased other long-term assets (2)	$	(16)
Decreased long-term debt (3)	$	(72)
Increased retained earnings (4)	$	10
Increased foreign currency translation adjustment (5)	$	13
Increased accumulated other comprehensive income (6)	$	146
Decreased current portion of future income tax asset (7)	$	(62)
Increased future income tax liability (7)	$	18

(1) Relates to the recognition of the current portion of the fair value of derivative financial instruments designated as cash flow hedges.

(2) Relates to the recognition of the long-term portion of the fair value of derivative financial instruments designated as cash flow and fair value hedges, as well as the reclassification of transaction costs and original issue discounts from deferred charges to long-term debt.

(3) Relates to the fair value impact of derivative financial instruments designated as fair value hedges, as well as the reclassification of transaction costs and original issue discounts.

(4) Relates to the impact on adoption of the measurement of ineffectiveness on derivative financial instruments designated as cash flow hedges.

(5) Relates to the retroactive restatement of foreign currency translation adjustment to accumulated other comprehensive income.

(6) Relates to the recognition of accumulated other comprehensive income arising from the measurement of effectiveness on derivative financial instruments designated as cash flow hedges.

(7) Relates to the future income tax impacts of the above noted adjustments.

3. OTHER LONG-TERM ASSETS

		Dec 31 2007		Dec 31 2006
Deferred charges (note 2)	$	28	$	109
Risk management (note 10)		-		128
Other		21		23
		49		260
Less: current portion		18		106
	$	31	$	154

4. LONG–TERM DEBT

	Pro forma Dec 31 2007[4]	Dec 31 2007	Dec 31 2006
Canadian dollar denominated debt			
Bank credit facilities (bankers' acceptances)	**$ 3,510**	**$ 4,696**	$ 6,621
Medium-term notes	**1,200**	**1,200**	925
	4,710	**5,896**	7,546
US dollar denominated debt			
Senior unsecured notes (2007 – US$62 million; and 2006 - US$93 million)	**61**	**61**	108
US dollar debt securities (2007 – US$5,108 million; and 2006 - US$2,908 million)	**6,244**	**5,048**	3,389
Less – original issue discount on senior unsecured notes and US dollar debt securities [1]	**(24)**	**(23)**	-
	6,281	**5,086**	3,497
Change in fair value of interest rate swaps on US dollar debt securities [2]	**9**	**9**	-
	6,290	**5,095**	3,497
Long-term debt before transaction costs	**11,000**	**10,991**	11,043
Less – transaction costs [1] [3]	**(60)**	**(51)**	-
	$ 10,940	**$ 10,940**	$ 11,043

(1) As described in note 2, effective January 1, 2007, 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 $9 million to reflect the fair value impact of hedge accounting (note 2).

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

(4) On January 10, 2008, the Company issued US$1,200 million of debt securities. The pro forma gives effect to the proceeds and their initial use.

Bank credit facilities

As at December 31, 2007, the Company had in place unsecured bank credit facilities of $6,209 million, comprised of:

- a $100 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.

During the second quarter of 2007, one of the revolving syndicated credit facilities was increased from $1,825 million to $2,230 million and a $500 million demand credit facility was terminated. The revolving syndicated credit facilities were also extended and now mature June 2012. Both 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.

In conjunction with the closing of the acquisition of Anadarko Canada Corporation in November 2006, the Company executed a $3,850 million, non-revolving syndicated credit facility maturing in October 2009. In March 2007, $1,500 million was repaid, reducing the facility to $2,350 million.

The weighted average interest rate of the bank credit facilities outstanding at December 31, 2007, was 5.2% (December 31, 2006 - 4.8%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $345 million, including $300 million related to the Horizon Oil Sands Project ("Horizon Project"), were outstanding at December 31, 2007.

Medium-term notes

In December 2007, the Company issued $400 million of unsecured notes maturing December 2010, bearing interest at 5.50%. 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 $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.

During the first quarter of 2007, $125 million of 7.40% unsecured debentures due March 1, 2007 were repaid.

Senior unsecured notes

During the second quarter of 2007, US$31 million of the senior unsecured notes were repaid.

US dollar debt securities

In March 2007, the Company issued US$2,200 million of unsecured notes, comprised of US$1,100 million of unsecured notes maturing May 2017 and US$1,100 million of unsecured notes maturing March 2038, bearing interest at 5.70% and 6.25%, respectively. Concurrently, the Company entered into cross currency interest rate swaps to fix the Canadian dollar interest and principal repayment amounts on the entire US$1,100 million of unsecured notes due May 2017 at 5.10% and C$1,287 million (note 10). The Company also entered into a cross currency interest rate swap to fix the Canadian dollar interest and principal repayment amounts on US$550 million of unsecured notes due March 2038 at 5.76% and C$644 million (note 10). Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

During the first quarter of 2007, the Company de-designated the portion of the US dollar denominated debt previously hedged against its net investment in US dollar based self-sustaining foreign operations. Accordingly, all foreign exchange (gains) losses arising each period on U.S. dollar denominated long-term debt are now recognized in the consolidated statement of earnings.

In September 2007, the Company filed a base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States until October 2009.

Subsequent to December 31, 2007, the Company issued US$1,200 million of unsecured notes under this 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. If issued, these securities will bear interest as determined at the date of issuance.

5. OTHER LONG–TERM LIABILITIES

		Dec 31 2007		Dec 31 2006
Asset retirement obligations	**$**	**1,074**	$	1,166
Stock-based compensation		**529**		744
Risk management (note 10)		**1,474**		-
Other		**101**		94
		3,178		2,004
Less: current portion		**1,617**		611
	$	**1,561**	$	1,393

Asset retirement obligations

At December 31, 2007, the Company's total estimated costs to settle its asset retirement obligations were approximately $4,426 million (December 31, 2006 - $4,497 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 6.6%. A reconciliation of the discounted asset retirement obligations is as follows:

		Year Ended Dec 31, 2007		Year Ended Dec 31, 2006
Balance – beginning of year	**$**	**1,166**	$	1,112
Liabilities incurred		**21**		26
Liabilities (disposed) acquired		**(65)**		56
Liabilities settled		**(71)**		(75)
Asset retirement obligation accretion		**70**		68
Revision of estimates		**35**		(21)
Foreign exchange		**(82)**		-
Balance – end of year	**$**	**1,074**	$	1,166

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 12-month period if all vested options are surrendered for cash settlement.

	Year Ended Dec 31, 2007	Year Ended Dec 31, 2006
Balance – beginning of year	**$ 744**	$ 891
Stock-based compensation	**193**	139
Payments for options surrendered	**(375)**	(264)
Transferred to common shares	**(91)**	(101)
Capitalized to Horizon Project	**58**	79
Balance – end of year	**529**	744
Less: current portion of stock-based compensation	**390**	611
	$ 139	$ 133

6. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Year Ended	
	Dec 31 2007	Dec 31 2006	**Dec 31 2007**	Dec 31 2006
Current income tax – North America	**$ 31**	$ 51	**$ 96**	$ 143
Current income tax – North Sea	**65**	30	**210**	30
Current income tax – Offshore West Africa	**27**	14	**74**	49
Current income tax expense	**123**	95	**380**	222
Future income tax (recovery) expense	**(847)**	135	**(456)**	652
Income tax (recovery) expense	**$ (724)**	$ 230	**$ (76)**	$ 874

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 a future period. North America current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary depending upon the nature, timing and amount of capital expenditures incurred in Canada in any particular year.

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

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 first quarter of 2006, enacted income tax rate changes resulted in an increase of future income tax liabilities of approximately $110 million in the UK North Sea.

During the second quarter of 2006, enacted income tax rate changes resulted in a reduction of future income tax liabilities of approximately $438 million in North America.

During the third quarter of 2006, enacted income tax rate changes resulted in a reduction of future income tax liabilities of approximately $67 million in Côte d’Ivoire, Offshore West Africa.

7. SHARE CAPTIAL

Issued Common shares	Year Ended Dec 31, 2007 Number of shares (thousands)		Amount
Balance – beginning of year	**537,903**	**$**	**2,562**
Issued upon exercise of stock options	**1,826**		**21**
Previously recognized liability on stock options exercised for common shares	**-**		**91**
Balance – end of year	**539,729**	**$**	**2,674**

Normal Course Issuer Bid

During 2007, the Company did not purchase any common shares for cancellation pursuant to the Normal Course Issuer Bid previously filed for the 12-month period beginning January 24, 2007 and ending January 23, 2008. The Company has not renewed the Normal Course Issuer Bid in 2008.

Dividend policy

In February 2008, the Board of Directors set the regular quarterly dividend at $0.10 per common share. The Company has paid regular quarterly dividends in January, April, July, and October of each year since 2001. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

In March 2007, the Board of Directors set the regular quarterly dividend at $0.085 per common share (2006 - $0.075 per common share).

Stock options

	Year Ended Dec 31, 2007 Stock options (thousands)		Weighted average exercise price
Outstanding – beginning of year	**34,425**	**$**	**33.77**
Granted	**7,498**	**$**	**70.03**
Surrendered for cash settlement	**(7,249)**	**$**	**16.10**
Exercised for common shares	**(1,826)**	**$**	**11.71**
Forfeited	**(2,199)**	**$**	**46.46**
Outstanding – end of year	**30,649**	**$**	**47.23**
Exercisable – end of year	**7,640**	**$**	**30.00**

8. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

	Dec 31 2007	Dec 31 2006
Derivative financial instruments designated as cash flow hedges	**$ 101**	$ -
Foreign currency translation adjustment	**(29)**	(13)
Accumulated other comprehensive income (loss)	**$ 72**	$ (13)

9. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Year Ended	
	Dec 31 2007	Dec 31 2006	**Dec 31 2007**	Dec 31 2006
Weighted average common shares outstanding (thousands) – basic and diluted	**539,652**	537,616	**539,336**	537,339
Net earnings – basic and diluted	**$ 798**	$ 313	**$ 2,608**	$ 2,524
Net earnings per common share – basic and diluted	**$ 1.48**	$ 0.58	**$ 4.84**	$ 4.70

10. FINANCIAL INSTRUMENTS

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 intended for trading or other speculative purposes.

As described in note 2, commencing January 1, 2007, the Company recorded all of its derivative financial instruments on the balance sheet at fair value, including those designated as hedges. As at December 31, 2006, the net unrecognized asset related to the estimated fair values of derivative financial instruments designated as hedges was $222 million.

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

	Year Ended Dec 31, 2007	Year Ended Dec 31, 2006	
Asset (liability)	**Risk management mark-to-market**	Risk management mark-to-market	Deferred revenue
Balance – beginning of year	**$ 128**	$ (877)	$ (8)
Retained earnings effect of adoption of financial instrument standards (note 2)	**14**	-	-
Net cost of outstanding put options	**58**	455	-
Net change in fair value of outstanding derivative financial instruments attributable to:			
- Risk management activities	**(1,400)**	1,005	-
- Interest expense	**9**	-	-
- Foreign exchange	**(350)**	-	-
- Other comprehensive income	**125**	-	-
Amortization of deferred revenue	**-**	-	8
	(1,416)	583	-
Add: Put premium financing obligations [(1)]	**(58)**	(455)	-
Balance – end of year	**(1,474)**	128	-
Less: current portion	**(1,227)**	88	-
	$ (247)	$ 40	$ -

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

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

	Three Months Ended		Year Ended	
	Dec 31 2007	Dec 31 2006	**Dec 31 2007**	Dec 31 2006
Net realized risk management loss	**$ 181**	$ 126	**$ 162**	$ 1,325
Net unrealized risk management mark-to-market loss (gain)	**845**	(241)	**1,400**	(1,013)
	$ 1,026	$ (115)	**$ 1,562**	$ 312

The Company had the following net financial derivatives outstanding as at December 31, 2007:

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Crude oil price collars [(1)]	Jan 2008	–	Mar 2008	50,000 bbl/d	US$60.00	–	US$80.06	WTI
	Jan 2008	–	Jun 2008	25,000 bbl/d	US$60.00	–	US$80.44	WTI
	Apr 2008	–	Sep 2008	25,000 bbl/d	US$60.00	–	US$80.46	WTI
	Jul 2008	–	Sep 2008	25,000 bbl/d	US$70.00	–	US$123.75	WTI
	Oct 2008	–	Dec 2008	25,000 bbl/d	US$70.00	–	US$112.63	WTI
	Jan 2008	–	Dec 2008	20,000 bbl/d	US$50.00	–	US$65.53	Mayan Heavy
	Jan 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$75.22	WTI
	Jan 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.05	WTI
	Jan 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.98	WTI
Crude oil puts	Jan 2008	–	Dec 2008	50,000 bbl/d			US$55.00	WTI

(1) Subsequent to December 31, 2007, the Company entered into 25,000 bbl/d of US$70.00 – US$111.56 WTI collars for the period January to December 2009.

The net cost of outstanding put options and their respective periods of settlement are as follows:

	Q1 2008	Q2 2008	Q3 2008	Q4 2008
Cost ($ millions)	US$14	US$15	US$15	US$15

	Remaining term			Volume	Weighted average price			Index
Natural gas								
AECO price collars	Jan 2008	–	Mar 2008	400,000 GJ/d	C$7.00	–	C$14.08	AECO
	Jan 2008	–	Mar 2008	500,000 GJ/d	C$7.50	–	C$10.81	AECO

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

	Remaining term			Amount ($ millions)	Fixed rate	Floating rate
Interest rate						
Swaps – fixed to floating	Jan 2008	–	Oct 2012	US$350	5.45%	LIBOR (1) + 0.81%
	Jan 2008	–	Dec 2014	US$350	4.90%	LIBOR (1) + 0.38%

(1) London Interbank Offered Rate

	Remaining term			Amount ($ millions)	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swaps	Jan 2008	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2008	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2008	–	Mar 2038	US$550	1.170	6.25%	5.76%

11. COMMITMENTS

The Company has committed to certain payments as follows:

	2008	2009	2010	2011	2012	Thereafter
Product transportation and pipeline	$ 232	$ 151	$ 137	$ 109	$ 91	$ 972
Offshore equipment operating leases (1)	$ 114	$ 129	$ 113	$ 111	$ 90	$ 387
Offshore drilling (2) (3)	$ 267	$ 185	$ 39	$ -	$ -	$ -
Asset retirement obligations (4)	$ 33	$ 4	$ 5	$ 4	$ 4	$ 4,376
Office leases	$ 26	$ 28	$ 28	$ 22	$ 3	$ -
Electricity and other	$ 166	$ 173	$ 25	$ 4	$ -	$ -

(1) Offshore equipment operating leases are primarily comprised of obligations related to floating production, storage and offtake vessels ("FPSO"). During 2006, the Company entered into an agreement to lease an additional FPSO commencing in 2008, in connection with the planned offshore development in Gabon, Offshore West Africa. During the initial term, the total annual payments for the Gabon FPSO are estimated to be US$50 million.

(2) During 2007, the Company entered into a one-year agreement for offshore drilling services related to the Baobab Field in Côte d'Ivoire, Offshore West Africa. The agreement is scheduled to commence in 2008, subject to rig availability. Estimated total payments of US$100 million, after joint venture recoveries, have been included in this table for the period 2008 - 2009.

(3) During 2007, the Company awarded contracts for a drilling rig and for the construction of wellhead towers in connection with the planned offshore development in Gabon, Offshore West Africa. Estimated total payments of US$393 million have been included in this table for the period 2008 - 2010.

(4) 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 2008 – 2012 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

In addition to the amounts disclosed above, the Company has budgeted construction costs of approximately $1.7 billion to $1.9 billion for 2008 related to the planned completion of Phase 1 of the Horizon Project.

12. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America				North Sea				Offshore West Africa			
	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	
	2007	2006	**2007**	2006	**2007**	2006	**2007**	2006	2007	2006	2007	2006
Segmented revenue	**2,571**	2,243	**10,149**	9,066	**367**	352	**1,597**	1,616	**260**	232	**776**	950
Less: royalties	**(317)**	(305)	**(1,318)**	(1,203)	**(1)**	(1)	**(3)**	(3)	**(25)**	(11)	**(70)**	(39)
Segmented revenue, net of royalties	**2,254**	1,938	**8,831**	7,863	**366**	351	**1,594**	1,613	**235**	221	**706**	911
Segmented expenses												
Production	**377**	400	**1,642**	1,436	**79**	77	**432**	390	**31**	38	**94**	106
Transportation and blending	**473**	337	**1,595**	1,465	**4**	4	**16**	15	**1**	1	**1**	1
Depletion, depreciation and amortization	**602**	580	**2,350**	1,897	**69**	85	**340**	297	**46**	57	**165**	189
Asset retirement obligation accretion	**10**	9	**38**	35	**7**	9	**30**	31	**-**	-	**2**	2
Realized risk management activities	**182**	76	**129**	1,022	**(1)**	50	**33**	303	**-**	-	**-**	-
Total segmented expenses	**1,644**	1,402	**5,754**	5,855	**158**	225	**851**	1,036	**78**	96	**262**	298
Segmented earnings (loss) before the following	**610**	536	**3,077**	2,008	**208**	126	**743**	577	**157**	125	**444**	613
Non-segmented expenses												
Administration												
Stock-based compensation (recovery) expense												
Interest, net												
Unrealized risk management activities												
Foreign exchange (gain) loss												
Total non-segmented expenses												
Earnings before taxes												
Taxes other than income tax												
Current income tax expense												
Future income tax (recovery) expense												
Net earnings												

(millions of Canadian dollars, unaudited)	Midstream Three Months Ended Dec 31		Midstream Year Ended Dec 31		Inter-segment elimination and other Three Months Ended Dec 31		Inter-segment elimination and other Year Ended Dec 31		Total Three Months Ended Dec 31		Total Year Ended Dec 31	
	2007	2006	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006	2007	2006
Segmented revenue	**19**	18	**74**	72	**(17)**	(19)	**(53)**	(61)	**3,200**	2,826	**12,543**	11,643
Less: royalties	**-**	-	**-**	-	**-**	-	**-**	-	**(343)**	(317)	**(1,391)**	(1,245)
Segmented revenue, net of royalties	**19**	18	**74**	72	**(17)**	(19)	**(53)**	(61)	**2,857**	2,509	**11,152**	10,398
Segmented expenses												
Production	**6**	6	**22**	23	**(2)**	(2)	**(6)**	(6)	**491**	519	**2,184**	1,949
Transportation and blending	**-**	-	**-**	-	**(11)**	(9)	**(42)**	(38)	**467**	333	**1,570**	1,443
Depletion, depreciation and amortization	**2**	2	**8**	8	**-**	-	**-**	-	**719**	724	**2,863**	2,391
Asset retirement obligation accretion	**-**	-	**-**	-	**-**	-	**-**	-	**17**	18	**70**	68
Realized risk management activities	**-**	-	**-**	-	**-**	-	**-**	-	**181**	126	**162**	1,325
Total segmented expenses	**8**	8	**30**	31	**(13)**	(11)	**(48)**	(44)	**1,875**	1,720	**6,849**	7,176
Segmented earnings (loss) before the following	**11**	10	**44**	41	**(4)**	(8)	**(5)**	(17)	**982**	789	**4,303**	3,222
Non-segmented expenses												
Administration									**42**	57	**208**	180
Stock-based compensation (recovery) expense									**(16)**	176	**193**	139
Interest, net									**51**	62	**276**	140
Unrealized risk management activities									**845**	(241)	**1,400**	(1,013)
Foreign exchange (gain) loss									**(47)**	151	**(471)**	122
Total non-segmented expenses									**875**	205	**1,606**	(432)
Earnings before taxes									**107**	584	**2,697**	3,654
Taxes other than income tax									**33**	41	**165**	256
Current income tax expense									**123**	95	**380**	222
Future income tax (recovery) expense									**(847)**	135	**(456)**	652
Net earnings									**798**	313	**2,608**	2,524

Net additions to property, plant and equipment

	Year Ended					
	Dec 31, 2007			Dec 31, 2006		
	Net Expenditures	**Non Cash/Fair Value Changes (1)**	**Capitalized Costs**	Net Expenditures	Non Cash/Fair Value Changes (1)	Capitalized Costs
North America	**$ 2,428**	**$ 52**	**$ 2,480**	$ 7,936	$ 1,521	$ 9,457
North Sea	**439**	**(77)**	**362**	646	(14)	632
Offshore West Africa	**159**	**(11)**	**148**	134	1	135
Other	**1**	**-**	**1**	11	-	11
Horizon Project (2)	**3,301**	**-**	**3,301**	3,185	-	3,185
Midstream	**6**	**-**	**6**	12	-	12
Head office	**20**	**-**	**20**	26	-	26
	$ 6,354	**$ (36)**	**$ 6,318**	$ 11,950	$ 1,508	$ 13,458

(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 and stock-based compensation.

	Property, plant and equipment		Total assets	
	Dec 31 2007	Dec 31 2006	**Dec 31 2007**	Dec 31 2006
Segmented assets				
North America	**$ 22,033**	$ 21,879	**$ 23,617**	$ 23,670
North Sea	**1,728**	2,029	**1,957**	2,248
Offshore West Africa	**1,188**	1,204	**1,354**	1,323
Other	**25**	24	**41**	46
Horizon Project	**8,651**	5,350	**8,740**	5,444
Midstream	**205**	207	**333**	355
Head office	**72**	74	**72**	74
	$ 33,902	$ 30,767	**$ 36,114**	$ 33,160

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, 2007, pre-tax interest of $356 million was capitalized to the Horizon Project (December 31, 2006 - $196 million).

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, 2007:

Interest coverage (times)	
Net earnings [(1)]	4.4x
Cash flow from operations [(2)]	10.8x

(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, February 28, 2008. The North American conference call number is 1-866-540-8136 and the outside North American conference call number is 001-416-340-8010. 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 6, 2008. 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 3243753.

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.

2008 FIRST QUARTER RESULTS

2008 first quarter results are scheduled for release after market close on Thursday, May 8, 2008. A conference call will be held on Friday, May 9, 2008 at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time.

For further information, please contact:

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