Canadian Natural

Third Quarter Report

Nine months ended September 30, 2007

Discipline | **Opportunity** | **Strategy**

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES THIRD QUARTER RESULTS

Commenting on third quarter 2007 results, Canadian Natural's Chairman, Allan Markin stated, "As we exit the first nine months of the year, we continue with our defined plan to manage costs while maximizing value. With the Horizon Project at 84% complete, we remain on track for targeted first oil in the third quarter of 2008 and maintain our focus on execution. Our defined plan will be optimized to take into account the new royalty program that was announced by the Government of Alberta on October 25th and expected to take effect in 2009. The new royalty program will have a negative impact, which we are still attempting to fully define, on our development plans in 2008 and in the future. As a result, we will carefully adjust our activity to ensure we are maximizing returns for our shareholders."

John Langille, Vice-Chairman, stated, "With respect to our balance sheet, our debt to book capitalization decreased as expected. On the marketing side, while we have seen record breaking US dollar reference prices for crude oil, pricing for natural gas in Canada has been weaker than expected. Warmer weather has dictated the soft market for natural gas, along with increasing liquefied natural gas (LNG) imports to the United States. Given that crude oil and natural gas realized prices are tied to US reference prices, the strengthening of the Canadian dollar relative to the US dollar has also had a negative impact on industry cash flows, lessening the impact of higher WTI pricing. However, Canadian Natural's extensive 2007 hedging program has reduced the impact on our realized natural gas price."

Steve Laut, President and Chief Operating Officer of Canadian Natural commented, "In the first nine months of 2007 we continued to demonstrate the strength and quality of our asset base which facilitates the allocation of our capital to higher returning projects. North American natural gas production, as expected, declined in the quarter and will continue to decline for the remainder of the year, reflecting our reduced capital spending in 2007 due to the lower returns currently being generated in the natural gas part of the business. Conversely, North American conventional liquids returns remain strong and quarterly production increased, reflecting growth at Pelican Lake as well as thermal wells transitioning off the steaming cycle and into production."

HIGHLIGHTS

($ millions, except as noted)	Three Months Ended **Sep 30 2007**	Jun 30 2007	Sep 30 2006	Nine Months Ended **Sep 30 2007**	Sep 30 2006
Net earnings	**$ 700**	$ 841	$ 1,116	**$ 1,810**	$ 2,211
per common share, basic and diluted	**$ 1.30**	$ 1.56	$ 2.08	**$ 3.36**	$ 4.12
Adjusted net earnings from operations (1)	**$ 644**	$ 595	$ 470	**$ 1,860**	$ 1,252
per common share, basic and diluted	**$ 1.19**	$ 1.10	$ 0.87	**$ 3.44**	$ 2.33
Cash flow from operations (2)	**$ 1,577**	$ 1,513	$ 1,313	**$ 4,712**	$ 3,639
per common share, basic and diluted	**$ 2.92**	$ 2.81	$ 2.44	**$ 8.74**	$ 6.77
Capital expenditures, net of dispositions	**$ 1,442**	$ 1,460	$ 1,661	**$ 4,911**	$ 5,528
Daily production, before royalties					
Natural gas (mmcf/d)	**1,647**	1,722	1,437	**1,695**	1,449
Crude oil and NGLs (bbl/d)	**333,062**	327,494	321,665	**329,208**	328,053
Equivalent production (boe/d)	**607,484**	614,461	561,152	**611,665**	569,590

(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.

- As expected, natural gas production volumes declined from the prior quarter in 2007 but continued to perform well. Natural gas production for Q3/07 averaged 1,647 mmcf/d, up 15% from 1,437 mmcf/d for Q3/06 and down 4% from 1,722 mmcf/d for Q2/07. Volumes in Q3/07 continued to reflect better than expected production from a number of wells, the addition of Anadarko Canada Corporation ("ACC") acquisition volumes, and continued high-grading of opportunities.
- Total crude oil and NGLs production for Q3/07 was 333,062 bbl/d. Q3/07 production was 4% higher than Q3/06 volumes of 321,665 bbl/d, and increased 2% from Q2/07 volumes of 327,494 bbl/d. Increased volumes in Q3/07 reflected the transition from steam cycles to production cycles for a number of thermal wells and continued development of Pelican Lake.
- Quarterly cash flow from operations was $1,577 million, an increase of 20% from Q3/06 and an increase of 4% from Q2/07. The increase from Q3/06 primarily reflected higher commodity realizations, lower year over year risk management losses, and the impact of higher sales volumes due to the acquisition of ACC. The increase from Q2/07 represented higher sales volumes in Q3/07. Cash flow in Q3/07 was negatively impacted by the strengthening of the Canadian dollar compared to the US dollar. The average exchange rate for Q3/07 was US$0.9565 per C$1.00 compared with US$0.9112 per C$1.00 for Q2/07 and US$0.8919 per C$1.00 for Q3/06.
- Q3/07 quarterly net earnings were $700 million, a 37% decrease from Q3/06 and a 17% decrease from Q2/07. Quarterly adjusted net earnings from operations for Q3/07 were $644 million, an increase of 8% from Q2/07 results and a 37% increase from Q3/06.
- Completed the Q3/07 North American drilling program targeting 153 net crude oil wells and 106 net natural gas wells with a 95% success ratio 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. Crude oil drilling activity was down from 263 net wells in Q3/06 due to the timing of the drilling program. Natural gas drilling decreased 5% from Q3/06, reflecting Canadian Natural's reallocation of capital towards a higher return crude oil drilling program.
- Maintained a strong undeveloped conventional core land base in Canada of 11.9 million net acres - a key asset for continued value growth.

- Continued production improvements at the Pelican Lake Field from new drilling activity and the expansion of the enhanced crude oil recovery program. Pelican Lake crude oil production averaged approximately 35,000 bbl/d during the quarter, up 17% or approximately 5,000 bbl/d from Q3/06. Production is targeted to continue to increase in Q4/07.
- Secured a deep water drilling rig for the Baobab Field. The equipment is targeted to be mobilized in Q1/08, enabling work to begin on the restoration of shut-in production. It is forecasted that 3 of the 5 shut-in Baobab wells should come back on stream over the course of 2008 and 2009.
- Work progress on the Horizon Oil Sands Project ("Horizon Project") exited Q3/07 at 84% complete and remains on track for first oil targeted Q3/08.
- On October 25, 2007 the Province of Alberta issued the details of its proposed changes to the Alberta crude oil and natural gas royalty regime, effective January 1, 2009. The Company expects that its 2009 and future Alberta royalty payments will increase as a result of the proposed royalty regime changes and that its level of activity in Alberta will be reduced from what it otherwise would have been in the absence of such royalty changes. In the current pricing and cost environment, the biggest reduction in the Company's Alberta activity will be experienced in the conventional natural gas business. The number of natural gas wells to be drilled in Alberta by the Company in 2008 and years beyond will be approximately 30% to 50% less than the number of such wells that would have otherwise been drilled in the absence of such royalty changes.
- Declared a quarterly cash dividend on common shares of C$0.085 per common share, payable January 1, 2008, a 13% increase over the 2006 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 Sep 30, 2007 (thousands of net acres)	Drilling activity nine months ended Sep 30, 2007 (net wells) (1)
Canadian conventional		
Northeast British Columbia	**2,419**	**53**
Northwest Alberta	**1,501**	**97**
Northern Plains	**6,523**	**507**
Southern Plains	**901**	**94**
Southeast Saskatchewan	**117**	**12**
In-situ Oil Sands	**482**	**179**
	11,943	**942**
Horizon Oil Sands Project	**115**	**98**
United Kingdom North Sea	**298**	**7**
Offshore West Africa	**206**	**4**
	12,562	**1,051**

(1) Drilling activity includes stratigraphic test and service wells

Drilling activity (number of wells)

	Nine Months Ended			
	Sep 30, 2007		Sep 30, 2006	
	Gross	**Net**	Gross	Net
Crude oil	**458**	**423**	471	426
Natural gas	**386**	**303**	774	581
Dry	**89**	**77**	102	91
Subtotal	**933**	**803**	1,347	1,098
Stratigraphic test / service wells	**250**	**248**	310	309
Total	**1,183**	**1,051**	1,657	1,407
Success rate (excluding stratigraphic test / service wells)		**90%**		92%

North America Conventional

North America natural gas

	Three Months Ended			Nine Months Ended	
	Sep 30 2007	Jun 30 2007	Sep 30 2006	**Sep 30 2007**	Sep 30 2006
Natural gas production (mmcf/d)	**1,622**	1,696	1,416	**1,670**	1,425
Net wells targeting natural gas	**106**	7	111	**358**	658
Net successful wells drilled	**96**	6	98	**303**	581
Success rate	**91%**	86%	88%	**85%**	88%

- Q3/07 North America natural gas production increased by 15% over Q3/06 and as expected, decreased by 4% from Q2/07. The increase from Q3/06 reflected the full impact of the acquisition of ACC natural gas volumes, whereas the decrease from Q2/07 reflected the Company's strategic decision to scale back the 2007 drilling program due to reallocation of capital to currently higher return crude oil projects.
- Canadian Natural targeted 106 net natural gas wells in Q3/07 including 32 wells in the Northern Plains region, 8 wells in the Northwest Alberta region, 63 well in the Southern Plains region and 3 wells in the Northeast British Columbia region, with an overall success rate of 91%. This compares to 111 net targeted natural gas wells in Q3/06, a 5% reduction.
- Planned drilling activity for Q4/07 includes 63 targeted natural gas wells.

North America crude oil and NGLs

	Three Months Ended			Nine Months Ended	
	Sep 30 2007	Jun 30 2007	Sep 30 2006	**Sep 30 2007**	Sep 30 2006
Crude oil and NGLs production (bbl/d)	**252,095**	240,420	233,440	**243,388**	230,430
Net wells targeting crude oil	**153**	78	263	**438**	431
Net successful wells drilled	**150**	75	253	**416**	417
Success rate	**98%**	96%	96%	**95%**	97%

- Q3/07 North America crude oil and NGLs production increased 8% from Q3/06 and increased 5% over Q2/07 levels. The majority of the incremental production volume was contributed by thermal crude oil and Pelican Lake crude oil. Primrose thermal production in Q3/07 was negatively impacted by unplanned outages at the processing plant due to lightning strikes and water treatment issues as well as higher than expected scaling rates on new pads. As a result, Primrose production was approximately 3,000 bbl/d less than Q3/07 expectations.
- During Q3/07, drilling activity included 94 net wells targeting heavy crude oil, 33 net wells targeting Pelican Lake crude oil, 21 net wells targeting thermal crude oil and 5 net wells targeting light crude oil.
- 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 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 conventional expansion 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. Final corporate sanction will be impacted by the terms of the proposed changes to the Alberta royalty regime, environmental regulations, and the final determination of associated capital costs.
- Development of new pads and secondary recovery conversion projects at Pelican Lake continued as expected throughout Q3/07. Drilling consisted of 34 horizontal wells, with plans to drill 13 additional horizontal wells for the remainder of 2007. The response from the water and polymer flood project continues to be positive. Pelican Lake production averaged approximately 35,000 bbl/d for Q3/07 compared to approximately 30,000 bbl/d for Q3/06.
- Conventional heavy crude oil production volumes increased slightly in Q3/07 compared to Q2/07. Production levels for primary were below target due to earlier than expected declines in certain older fields.
- Planned drilling activity for Q4/07 includes 120 net crude oil wells, excluding stratigraphic test and service wells.

International

The Company operates in the North Sea and Offshore West Africa where production of light quality crude oil is targeted in conjunction with natural gas that may be produced in association with crude oil production.

	Three Months Ended			Nine Months Ended	
	Sep 30 2007	Jun 30 2007	Sep 30 2006	**Sep 30 2007**	Sep 30 2006
Crude oil production (bbl/d)					
North Sea	**52,013**	57,286	53,988	**57,020**	59,473
Offshore West Africa	**28,954**	29,788	34,237	**28,800**	38,150
Natural gas production (mmcf/d)					
North Sea	**10**	15	11	**13**	15
Offshore West Africa	**15**	11	10	**12**	9
Net wells targeting crude oil	**2.2**	3.1	2.2	**7.3**	9.2
Net successful wells drilled	**2.2**	3.1	2.2	**7.3**	9.2
Success rate	**100%**	100%	100%	**100%**	100%

North Sea

- Planned platform maintenance shutdowns scheduled for Q3/07 at Ninian, B-Block and T-Block were successfully completed, reducing Q3/07 volumes compared to Q2/07, as expected. During Q3/07, 1.0 net crude oil well was drilled along with 0.9 net water injectors.
- The development of the Lyell Field continued with the second well onstream in Q3/07 through the existing infrastructure. Production from the initial Lyell producing wells has been below expectations. Although the wells encountered thick pay sections, the formation is tight and as a result production dropped from high initial rates to much lower than targeted stabilized rates. As a result, continued development of the Lyell Field is under review.

- Commissioning of the Columba E raw water injection facilities was completed in Q2/07 along with 2 water injection wells facilitating water injection into the reservoir to commence. The subsea wells are currently injecting 2,500 bbl/d of water, lower than targeted, as they encountered significantly tighter formations than expected. As a result production increases from Columba will be delayed.
- In Q3/07, Canadian Natural entered into a Sale and Purchase Agreement for the disposal, subject to government and partner consents, of its entire working interest in the Balmoral, Stirling and Glamis Fields (B-Block). During Q3/07, transition arrangements and consents progressed, with closing expected during Q4/07 or early in 2008. In 2007, the B-Block has 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 year to date.

Offshore West Africa

- During Q3/07, 1.2 net wells were drilled with 0.6 additional net wells drilling at the end of the quarter.
- West Espoir commenced production in mid 2006. During Q3/07, 1 additional production well and 1 additional injector were added. The West Espoir area has seen favorable production growth and development drilling is continuing into 2008 with producers and injectors being brought on-line as they are completed.
- During Q3/07, in order to increase its throughput handling capability Canadian Natural awarded a contract for the upgrade of the Espoir Floating Production Storage and Offtake ("FPSO") vessel. Design and procurement work commenced during the quarter, with installation of equipment on the FPSO targeted to start in late 2009.
- A deep water drilling rig has been secured for the Baobab Field. The rig is now targeted to be mobilized in Q1/08. The Company is targeting to bring 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. The project is on schedule with drilling targeted to commence in Q2/08 and first crude oil is targeted for late 2008 or early 2009. Production is targeted to plateau at approximately 20,000 bbl/d in Q4/09.

Horizon Project

- Canadian Natural achieved an overall work progress at the end of the quarter at 84% complete and construction 76% complete. All major vessels have either been erected or are currently on site. Work scheduled for the coming months will continue to focus on mechanical construction, which is scheduled to be completed through a combination of lump sum and reimbursable contracts.
- The Horizon Project remains on track for targeted first oil in Q3/08. Project progress achieved 9% progress despite the distraction of Alberta-wide labour negotiations that occurred throughout the summer.
- Pre-commissioning work has been initiated in the area of Utilities and Offsites and Bitumen Production, with hydro-testing targeted for completion.
- Previous decisions to defer several contracts and delay certain projects to capture cost reduction opportunities has caused overlap between some construction projects on the site and has resulted in an increase in peak project manpower requirements. Canadian Natural's supporting camp and transportation infrastructure has been successfully expanded to accommodate the higher peak in manpower to ensure workers are adequately accommodated.
- As a result, some work has been pushed into the more challenging winter months, resulting in a modest increase in the forecast completion cost for the Horizon Project. The Company's current Horizon Project completion cost forecast has been increased from the 5% to 12% range provided in the first quarter 2007 Horizon Project Update to an 8% to 14% range over the original $6.8 billion estimate.

- The quarterly update for Phase 1 of the Horizon Project is as follows:

Project status summary

	June 30, 2007	September 30, 2007		December 31, 2007	
	Actual	Actual	Original Plan	Forecast	Original Plan
Phase 1 - Work progress (cumulative)	75%	84%	88%	90%	94%
Phase 1 - Construction capital spending* (cumulative)	79%	89%	85%	99%	92%

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

Accomplished to the End of the Third Quarter of 2007

Detailed Engineering
- Overall detailed engineering 98% complete and substantially completed in most areas.

Procurement
- Overall procurement progress is 98% complete.
- Have awarded over $5.5 billion in purchase orders and contracts to date.
- Delivered over 35,000 standard loads of all kinds to site.
- Operations and maintenance service and supply agreements are in negotiation.

Modularization
- Delivered an additional 80 oversized loads to site for a total of 1,504 loads, which represents approximately 91% of the total requirement.

Construction
- Overall construction progress is 76% complete.
- Mine overburden removal has moved 43.8 million bank cubic meters, which represents approximately 63% of the total to be moved and is slightly ahead of schedule.
- Energized Main Electrical Substations.
- Completed construction of Raw Water Pond.
- Started pre-commissioning activities in Bitumen Production Areas.
- Froth tank completed and hydro-tested.
- Commenced extraction plant hydro-testing.
- Permanent power energized in R1/R2 corridors pumphouses.
- Started commissioning of Recycle Water Pond.

Milestones for the Fourth Quarter of 2007

- Complete the closure of Dyke 10 (external tailings pond) in Mining.
- Complete erection of Crushing Plants and conveyors in Ore Preparation Area.
- Complete Primary Separation Cells in Extraction.
- Complete Main Control Room and Distributed Control Systems installation.
- Complete construction of Main Laboratory.

Plant and System Commissioning Schedule

Completed
- Permanent Potable Water Treatment
- Permanent Sewage Treatment
- Natural Gas Pipeline
- Raw and Recycled Water Pipelines
- River Water Intake and Pumphouse

Q4/07
- Raw Water Pond and Pumphouse
- Recycle Water Pond and Pumphouse
- Extraction
- Electrical Distribution System

Q1/08
- Cooling and Heating System
- Main Pipe Rack

Q2/08
- Cogeneration
- Ore Preparation Plant
- Froth Treatment
- Pipeline Corridors
- Hydrogen Plant
- Coker / Diluent Recovery Unit
- Gas Treating and Sulphur Recovery
- Synthetic crude oil pipeline
- Sulphur block pipelines
- West Tank Farm (inter-plant)

Q3/08
- Hydrotreating
- East Tank Farm (product)

Operations Readiness

- The Company expects to meet its hiring requirements by the end of the year for the Operations group. Training programs are in place and, in anticipation of turnover, Operations have commenced the review of systems in certain plants.

MARKETING	Three Months Ended			Nine Months Ended	
	Sep 30 2007	Jun 30 2007	Sep 30 2006	**Sep 30 2007**	Sep 30 2006
Crude oil and NGLs pricing					
WTI[1] benchmark price (US$/bbl)	**$ 75.33**	$ 65.02	$ 70.55	**$ 66.26**	$ 68.29
Lloyd Blend Heavy oil differential from WTI (%)	**30%**	30%	27%	**29%**	32%
Corporate average pricing before risk management (C$/bbl)	**$ 58.10**	$ 53.74	$ 62.55	**$ 54.57**	$ 55.91
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 5.32**	$ 6.99	$ 5.72	**$ 6.46**	$ 6.82
Corporate average pricing before risk management (C$/mcf)	**$ 5.87**	$ 7.44	$ 5.83	**$ 7.03**	$ 6.75

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

- In Q3/07, the Lloyd Blend heavy crude oil differential as a percent of WTI was 30%, compared to 27% in Q3/06.

- Canadian Natural has committed to 25,000 bbl/d of pipeline capacity on the Pegasus Pipeline which transports Company crude oil volumes to the U.S. Gulf Coast as part of the Company's efforts towards working with various industry groups to find new markets for Western Canadian heavy crude oil and to ease the logistical constraints in getting crude oil to the area. The pipeline reversal has had the impact of improving the corporate realized price on Canadian Natural's heavy crude oil production. The heavy crude oil sold to the Gulf Coast receives Mayan equivalent pricing, a premium to the Lloyd Blend price. For Q3/07, the Mayan differential to WTI averaged US$12.30/bbl or 16%.
- During Q3/07, the Company contributed approximately 134,000 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 Q3/07 due to a significant increase in liquefied natural gas (LNG) imports to the United States along with stable production levels in that country. 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 607,000 boe/d in Q3/07, comprised of approximately 45% natural gas and 55% crude oil - with 95% of production located in G8 countries with stable and secure economies.
  - Financial stability and liquidity – cash flow from operations of $4.7 billion for the first nine months of 2007, available unused bank lines of $1.3 billion at September 30, 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.
- In September 2007, the Company filed a short form prospectus that allows for the issue of up to US$3.0 billion of debt securities in the United States until October 2009. Simultaneously the Company filed a short form shelf prospectus that allows for the issue of up to $3.0 billion of medium-term notes in Canada until October 2009. If issued, these securities will bear interest as determined at the date of issuance.
- Declared a quarterly cash dividend on common shares of C$0.085 per common share, payable January 1, 2008, a 13% increase over the 2006 quarterly dividend.

OUTLOOK

The Company forecasts 2007 production levels before royalties to average between 1,664 and 1,676 mmcf/d of natural gas and between 326,000 and 334,000 bbl/d of crude oil and NGLs. Q4/07 production guidance before royalties is forecast to average between 1,577 and 1,616 mmcf/d of natural gas and between 321,000 and 344,000 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/.

MANAGEMENT’S DISCUSSION AND ANALYSIS

Forward-Looking Statements

Certain statements in this document or documents incorporated herein by reference for Canadian Natural Resources Limited (the “Company”) constitute “forward-looking statements” within the meaning of the United States Private Securities Litigation Reform Act of 1995. These forward-looking statements can generally be identified as such because of the context of the statements including words such as the Company “believes”, “anticipates”, “expects”, “plans”, “estimates”, ”targets”, or words of a similar nature.

The forward-looking statements are based on current expectations and are subject to known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements of the Company, or industry results, 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; foreign currency exchange rates; 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; availability and cost of seismic, drilling and other equipment; ability of the Company to complete its capital programs; ability of the Company to transport its products to market; 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 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; success of exploration and development activities; timing and success of integrating the business and operations of acquired companies; production levels; uncertainty of reserve estimates; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations); asset retirement obligations; and other circumstances affecting revenues and expenses. Our domestic operations are subject to governmental risks that may impact our operations. Our domestic 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. 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.

Disclosure related to expected future commodity pricing, production volumes, royalties, capital expenditures and other 2007 guidance provided throughout this Management’s Discussion and Analysis (“MD&A”), constitutes forward-looking statements as described above.

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.

Readers are cautioned that the foregoing list of important factors is not exhaustive. 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 nine months ended September 30, 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.

Certain figures related to the presentation of gross revenues and gross transportation and blending provided for the nine and three months ended September 30, 2006 have been reclassified to conform to the presentation adopted in the fourth quarter of 2006.

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, 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 nine and three months ended September 30, 2007 in relation to the comparable periods in 2006 and the second quarter of 2007. The accompanying tables form an integral part of this MD&A. This MD&A is dated October 30, 2007. 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			Nine Months Ended	
	Sep 30 2007	Jun 30 2007	Sep 30 2006 [1]	**Sep 30 2007**	Sep 30 2006 [1]
Revenue, before royalties	**$ 3,073**	$ 3,152	$ 3,108	**$ 9,343**	$ 8,817
Net earnings	**$ 700**	$ 841	$ 1,116	**$ 1,810**	$ 2,211
Per common share – basic and diluted	**$ 1.30**	$ 1.56	$ 2.08	**$ 3.36**	$ 4.12
Adjusted net earnings from operations [2]	**$ 644**	$ 595	$ 470	**$ 1,860**	$ 1,252
Per common share – basic and diluted	**$ 1.19**	$ 1.10	$ 0.87	**$ 3.44**	$ 2.33
Cash flow from operations [3]	**$ 1,577**	$ 1,513	$ 1,313	**$ 4,712**	$ 3,639
Per common share – basic and diluted	**$ 2.92**	$ 2.81	$ 2.44	**$ 8.74**	$ 6.77
Capital expenditures, net of dispositions	**$ 1,442**	$ 1,460	$ 1,661	**$ 4,911**	$ 5,528

(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.

(2) 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. This reconciliation 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.

(3) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items. 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. Cash flow from operations may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings from Operations

	Three Months Ended			*Nine Months Ended*	
($ millions)	***Sep 30 2007***	*Jun 30 2007*	*Sep 30 2006*	***Sep 30 2007***	*Sep 30 2006*
Net earnings as reported	***$ 700***	*$ 841*	*$ 1,116*	***$ 1,810***	*$ 2,211*
Stock-based compensation expense (recovery), net of tax[a]	***54***	*74*	*(92)*	***145***	*(25)*
Unrealized risk management loss (gain), net of tax[b]	***57***	*(35)*	*(496)*	***384***	*(508)*
Unrealized foreign exchange (gain) loss, net of tax[c]	***(167)***	*(214)*	*9*	***(408)***	*(31)*
Effect of statutory tax rate changes on future income tax liabilities[d]	***-***	*(71)*	*(67)*	***(71)***	*(395)*
Adjusted net earnings from operations	***$ 644***	*$ 595*	*$ 470*	***$ 1,860***	*$ 1,252*

(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 flow through net earnings or are capitalized to the Horizon Oil Sands Project.

(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 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 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 **Sep 30 2007**	 Jun 30 2007	 Sep 30 2006	Nine Months Ended **Sep 30 2007**	 Sep 30 2006
Net earnings	**$ 700**	$ 841	$ 1,116	**$ 1,810**	$ 2,211
Non-cash items:					
Depletion, depreciation and amortization	**715**	720	589	**2,144**	1,667
Asset retirement obligation accretion	**18**	17	17	**53**	50
Stock-based compensation expense (recovery)	**78**	106	(135)	**209**	(37)
Unrealized risk management loss (gain)	**76**	(57)	(754)	**555**	(772)
Unrealized foreign exchange (gain) loss	**(195)**	(250)	11	**(477)**	(37)
Deferred petroleum revenue tax expense (recovery)	**10**	20	(4)	**27**	40
Future income tax expense	**175**	116	473	**391**	517
Cash flow from operations	**$ 1,577**	$ 1,513	$ 1,313	**$ 4,712**	$ 3,639

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

For the nine months ended September 30, 2007, the Company reported net earnings of $1,810 million compared to net earnings of $2,211 million for the nine months ended September 30, 2006. Net earnings for the nine months ended September 30, 2007 included unrealized after-tax expenses of $50 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 changes on future income tax liabilities, compared to net after-tax income of $959 million for the nine months ended September 30, 2006. Excluding these items, adjusted net earnings from operations for the nine months ended September 30, 2007 increased to $1,860 million from $1,252 million for the nine months ended September 30, 2006. The increase from the comparable period in 2006 was primarily due to increased sales volumes and decreased realized risk management losses. These factors were partially offset by increased production expense, increased depletion, depreciation and amortization expense, and the impact of the strengthening of the Canadian dollar relative to the US dollar.

Net earnings in the third quarter of 2007 were $700 million compared to net earnings of $1,116 million in the third quarter of 2006 and net earnings of $841 million in the prior quarter. Net earnings in the third quarter of 2007 included unrealized after-tax income of $56 million related to the effects of risk management activities, fluctuations in foreign exchange rates and stock-based compensation expense, compared to net after-tax income of $646 million for the third quarter of 2006 and net after-tax income of $246 million in the prior quarter. Excluding these items, adjusted net earnings from operations in the third quarter of 2007 increased to $644 million from $470 million in the third quarter of 2006, and from $595 million in the prior quarter. The increase in adjusted net earnings from the third quarter of 2006 was primarily due to the impact of increased sales volumes and decreased realized risk management losses. These factors were partially offset by the impact of the stronger Canadian dollar relative to the US dollar and increased depletion, depreciation and amortization expense. The increase from the prior quarter was primarily due to increased crude oil pricing, decreased production costs and increased realized risk management gains on natural gas, partially offset by decreased natural gas pricing and the impact of the stronger Canadian dollar relative to the US dollar.

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 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 expenditure program 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 60% of expected crude oil volumes and natural gas volumes are hedged for the remainder of 2007.

The Company's outstanding commodity related net financial derivatives as at September 30, 2007 are detailed on page 41 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 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 September 30, 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 $555 million ($384 million after-tax) on its commodity risk management activities for the nine months ended September 30, 2007, including a $76 million ($57 million after-tax) unrealized loss for the three months ended September 30, 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 31 of this MD&A.

The Company also recorded a $209 million ($145 million after-tax) stock-based compensation expense as a result of the 22% increase in the Company's share price in the nine months ended September 30, 2007, and a $78 million ($54 million after-tax) stock-based compensation expense as a result of the 7% increase in the Company's share price for the three months ended September 30, 2007 (Company's share price as at: September 30, 2007 – C$75.56; June 30, 2007 – C$70.78; December 31, 2006 – C$62.15; September 30, 2006 – C$50.94). 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 each quarter 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 September 30, 2007 reflected the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on September 30, 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 nine months ended September 30, 2007 increased to $4,712 million from $3,639 million for the nine months ended September 30, 2006. The increase from the comparable period in 2006 was primarily due to increased sales volumes and decreased realized risk management losses, offset by increased production expense, higher cash taxes and the impact of the strengthening of the Canadian dollar relative to the US dollar.

Cash flow from operations for the third quarter of 2007 increased to $1,577 million from $1,313 million for the third quarter of 2006, and from $1,513 million in the prior quarter. The increase from the third quarter of 2006 was primarily due to the impact of increased sales volumes and decreased realized risk management losses, partially offset by the impact of the stronger Canadian dollar relative to the US dollar. The increase from the prior quarter was primarily due to increased crude oil pricing, lower production costs and increased realized risk management gains on natural gas, partially offset by decreased natural gas production and pricing, higher cash taxes and the impact of the stronger Canadian dollar relative to the US dollar.

Total production before royalties increased 7% to average 611,665 boe/d for the nine months ended September 30, 2007 from 569,590 boe/d for the nine months ended September 30, 2006. Production for the third quarter of 2007 increased 8% to 607,484 boe/d from 561,152 boe/d in the third quarter of 2006 and decreased 1% from 614,461 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)		**Sep 30 2007**		Jun 30 2007		Mar 31 2007		Dec 31 2006
Revenue, before royalties	**$**	**3,073**	$	3,152	$	3,118	$	2,826
Net earnings	**$**	**700**	$	841	$	269	$	313
Net earnings per common share								
– Basic and diluted	**$**	**1.30**	$	1.56	$	0.50	$	0.58

($ millions, except per common share amounts)		Sep 30 2006		Jun 30 2006		Mar 31 2006		Dec 31 2005
Revenue, before royalties [(1)]	$	3,108	$	3,041	$	2,668	$	3,319
Net earnings	$	1,116	$	1,038	$	57	$	1,104
Net earnings per common share								
– Basic and diluted	$	2.08	$	1.93	$	0.11	$	2.06

(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, increased sales volumes, the impact of mark-to-market accounting of financial instruments and adjustments to future income tax liabilities due to jurisdictional tax rate 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 milder temperatures experienced during 2007 and 2006.

- Crude oil and NGLs sales volumes

  Crude oil and NGLs sales volumes primarily reflected increased production from the Company's Primrose thermal projects, the positive results from the Pelican Lake water and polymer flood projects, 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 reflected additional natural gas volumes as a result of the ACC acquisition and internally generated growth. The increase was 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, UK pounds sterling denominated working capital balances, and the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars.

- Commodity and cross currency 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 and cross currency hedges.

- Changes in tax rates

  Income tax expense and recovery fluctuations include jurisdictional tax rate changes 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. The liability reflected a general increase in the Company's share price over the eight most recently completed quarters.

- Production expense

  Production expense has increased primarily due to industry-wide inflationary cost pressures.

- 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, a higher depletion base related to the ACC acquisition, and increased estimated future costs to develop the Company's proved undeveloped reserves, together with the impact of higher sales volumes.

OPERATING HIGHLIGHTS

	Three Months Ended			Nine Months Ended	
	Sep 30 2007	Jun 30 2007	Sep 30 2006	**Sep 30 2007**	Sep 30 2006
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 58.10**	$ 53.74	$ 62.55	**$ 54.57**	$ 55.91
Royalties	**6.65**	5.46	5.11	**5.69**	4.61
Production expense	**13.13**	15.01	13.47	**13.97**	12.29
Netback	**$ 38.32**	$ 33.27	$ 43.97	**$ 34.91**	$ 39.01
Natural gas ($/mcf) (1)					
Sales price (2)	**$ 5.87**	$ 7.44	$ 5.83	**$ 7.03**	$ 6.75
Royalties	**0.89**	1.10	1.11	**1.16**	1.31
Production expense	**0.88**	0.89	0.84	**0.91**	0.81
Netback	**$ 4.10**	$ 5.45	$ 3.88	**$ 4.96**	$ 4.63
Barrels of oil equivalent ($/boe) (1)					
Sales price (2)	**$ 47.96**	$ 49.70	$ 51.21	**$ 48.99**	$ 49.38
Royalties	**6.07**	5.99	5.75	**6.27**	5.99
Production expense	**9.62**	10.44	10.01	**10.05**	9.13
Netback	**$ 32.27**	$ 33.27	$ 35.45	**$ 32.67**	$ 34.26

(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			Nine Months Ended	
	Sep 30 2007	Jun 30 2007	Sep 30 2006	**Sep 30 2007**	Sep 30 2006
WTI benchmark price (US$/bbl)	**$ 75.33**	$ 65.02	$ 70.55	**$ 66.26**	$ 68.29
Dated Brent benchmark price (US$/bbl)	**$ 74.85**	$ 68.74	$ 69.58	**$ 67.18**	$ 67.03
Differential to LLB blend (US$/bbl)	**$ 22.69**	$ 19.42	$ 19.08	**$ 19.33**	$ 21.82
LLB blend differential from WTI (%)	**30%**	30%	27%	**29%**	32%
Condensate benchmark price (US$/bbl)	**$ 75.93**	$ 65.66	$ 70.26	**$ 66.82**	$ 68.49
NYMEX benchmark price (US$/mmbtu)	**$ 6.13**	$ 7.56	$ 6.52	**$ 6.88**	$ 7.47
AECO benchmark price (C$/GJ)	**$ 5.32**	$ 6.99	$ 5.72	**$ 6.46**	$ 6.82
US / Cdn dollar average exchange rate (US$)	**$ 0.9565**	$ 0.9112	$ 0.8919	**$ 0.9045**	$ 0.8830

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$66.26 per bbl for the nine months ended September 30, 2007, a decrease of 3% from US$68.29 per bbl for the nine months ended September 30, 2006. In the third quarter of 2007, WTI averaged US$75.33 per bbl, an increase of 7% from US$70.55 per bbl in the third quarter of 2006, and an increase of 16% from US$65.02 per bbl in the prior quarter. Increases in WTI pricing in the third quarter reflected continued strong demand for crude oil and continued geopolitical events causing 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 the third quarter of 2007. Dated Brent ("Brent") averaged US$67.18 per bbl for the nine months ended September 30, 2007, comparable to US$67.03 per bbl for the nine months ended September 30, 2006. In the third quarter of 2007, Brent averaged US$74.85 per bbl, an increase of 8% compared to US$69.58 per bbl for the third quarter of 2006, and an increase of 9% from US$68.74 per bbl for the prior quarter. As noted above, the differential between Brent and WTI returned to more historical levels as logistical constraints at Cushing, Oklahoma eased during the third quarter.

Company-wide, realized crude oil prices for the nine months ended September 30, 2007 decreased slightly as a result of lower benchmark WTI pricing, partially offset by a narrower Heavy Differential in North America. The Heavy Differential averaged 29% for the nine months ended September 30, 2007 compared to 32% for the nine months ended September 30, 2006. For the third quarter of 2007, the Heavy Differential averaged 30% compared to 27% for the third 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 maintenance and unplanned shut-downs. In the third quarter, 2007 realized prices continued to be impacted by the stronger Canadian dollar as Company realized prices are based on US dollar denominated benchmarks.

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.

NYMEX natural gas prices averaged US$6.88 per mmbtu for the nine months ended September 30, 2007, a decrease of 8% from US$7.47 per mmbtu for the nine months ended September 30, 2006. In the third quarter of 2007, the NYMEX natural gas price averaged US$6.13 per mmbtu, a decrease of 6% from US$6.52 per mmbtu for the third quarter of 2006, and a decrease of 19% from US$7.56 per mmbtu for the prior quarter. AECO natural gas prices decreased 5% to average $6.46 per GJ for the nine months ended September 30, 2007, compared to $6.82 per GJ for the nine months ended September 30, 2006. In the third quarter of 2007 AECO natural gas prices averaged $5.32 per GJ, a decrease of 7% from $5.72 per GJ in the third quarter of 2006, and a decrease of 24% from $6.99 per GJ for the prior quarter. Fluctuations in natural gas prices from the comparable periods in 2006 were primarily related to weather and storage levels. Natural gas inventory levels in North America continued to remain high in the third quarter of 2007 due to the significant increase in liquefied natural gas imports into the US and 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 production 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, specifically 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 is drafting policy and legislation to control greenhouse gas emissions. In Alberta, provincial regulations came into effect July 1, 2007, while in the UK greenhouse gas regulations have been in effect since 2005. The Company has processes in place to comply with the regulations. The additional requirements of greenhouse gas 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 the 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 basis pre-payout and 25% to 40% on a net 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 expects that its 2009 and future Alberta royalty payments will increase as a result of the proposed royalty regime changes and that its level of activity in Alberta will be reduced from what it otherwise would have been in the absence of such royalty changes. In the current pricing and cost environment, the biggest reduction in the Company's Alberta activity will be experienced in the conventional natural gas business. The number of natural gas wells to be drilled in Alberta by the Company in 2008 and years beyond will be approximately 30% to 50% less than the number of such wells that would have otherwise been drilled in the absence of such royalty changes.

PRODUCT PRICES [(1)]

	Three Months Ended			Nine Months Ended	
	Sep 30 2007	Jun 30 2007	Sep 30 2006	**Sep 30 2007**	Sep 30 2006
Crude oil and NGLs ($/bbl) [(2)]					
North America	**$ 52.47**	$ 47.20	$ 55.97	**$ 48.68**	$ 48.82
North Sea	**$ 77.55**	$ 73.18	$ 78.68	**$ 72.86**	$ 74.09
Offshore West Africa	**$ 70.52**	$ 72.84	$ 70.59	**$ 67.37**	$ 69.58
Company average	**$ 58.10**	$ 53.74	$ 62.55	**$ 54.57**	$ 55.91
Natural gas ($/mcf) [(2)]					
North America	**$ 5.88**	$ 7.47	$ 5.86	**$ 7.05**	$ 6.81
North Sea	**$ 5.26**	$ 3.92	$ 2.38	**$ 4.47**	$ 2.36
Offshore West Africa	**$ 5.31**	$ 6.22	$ 4.97	**$ 5.76**	$ 5.27
Company average	**$ 5.87**	$ 7.44	$ 5.83	**$ 7.03**	$ 6.75
Company average ($/boe)[(2)]	**$ 47.96**	$ 49.70	$ 51.21	**$ 48.99**	$ 49.38
Percentage of revenue (excluding midstream revenue)					
Crude oil and NGLs	**67%**	57%	72%	**60%**	65%
Natural gas	**33%**	43%	28%	**40%**	35%

(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.

The Company's realized crude oil prices decreased to average $54.57 per bbl for the nine months ended September 30, 2007 from $55.91 per bbl for the nine months ended September 30, 2006. Realized crude oil prices for the third quarter of 2007 decreased 7% to average $58.10 per bbl from $62.55 per bbl for the third quarter of 2006, and increased 8% from $53.74 per bbl for the prior quarter. The Company's realized crude oil prices decreased slightly from the nine months ended September 30, 2006 as a result of the stronger Canadian dollar and lower benchmark WTI pricing, partially offset by a narrower Heavy Differential in North America. The increase from the prior quarter primarily reflected higher WTI benchmark pricing.

The Company's realized natural gas price increased 4% to average $7.03 per mcf for the nine months ended September 30, 2007 from $6.75 per mcf for the nine months ended September 30, 2006. In the third quarter of 2007, the Company's realized natural gas price increased slightly to average $5.87 per mcf from $5.83 per mcf in the third quarter of 2006, and decreased 21% from $7.44 per mcf for the prior quarter. Fluctuations in natural gas prices from the comparable periods in 2006 and the second quarter of 2007 were primarily related to weather and storage levels.

North America

North America realized crude oil prices decreased slightly to average $48.68 per bbl for the nine months ended September 30, 2007 from $48.82 per bbl for the nine months ended September 30, 2006. Realized crude oil prices in the third quarter of 2007 averaged $52.47 per bbl, a 6% decrease from $55.97 per bbl for the third quarter of 2006, and increased 11% from $47.20 per bbl for the prior quarter. The decrease in realized crude oil prices from the third quarter of 2006 was due to the stronger Canadian dollar and the widening of the Heavy Differential, partially offset by the increase in WTI benchmark price, while the increase from the prior quarter was due to the increase in WTI benchmark pricing, partially offset by the widening Heavy Differential and the stronger Canadian dollar relative to the US dollar.

In North America, the Company continues to focus on its crude oil marketing strategy, including the development of a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil conversion capacity. During the third quarter, the Company contributed approximately 134,000 bbl/d of heavy crude oil blends to the Western Canadian Select stream.

North America realized natural gas prices increased 4% to average $7.05 per mcf for the nine months ended September 30, 2007 from $6.81 per mcf for the nine months ended September 30, 2006. The realized natural gas price in the third quarter of 2007 averaged $5.88 per mcf, comparable to $5.86 per mcf for the third quarter of 2006, and a 21% decrease from $7.47 per mcf for the prior quarter. Fluctuations in natural gas prices from the comparable periods in 2006 and the second 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:

	Three Months Ended		
	Sep 30 2007	Jun 30 2007	Sep 30 2006
Wellhead Price [1] [2]			
Light / medium crude oil and NGLs (C$/bbl)	**$ 67.55**	$ 63.09	$ 72.25
Pelican Lake crude oil (C$/bbl)	**$ 48.91**	$ 44.49	$ 53.84
Primary heavy crude oil (C$/bbl)	**$ 47.47**	$ 42.30	$ 52.15
Thermal heavy crude oil (C$/bbl)	**$ 48.99**	$ 41.09	$ 50.36
Natural gas (C$/mcf)	**$ 5.88**	$ 7.47	$ 5.86

(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 decreased marginally to average $72.86 per bbl for the nine months ended September 30, 2007 from $74.09 per bbl for the nine months ended September 30, 2006. Realized crude oil prices in the third quarter of 2007 averaged $77.55 per bbl, a slight decrease from $78.68 per bbl in the third quarter of 2006, and increased 6% from $73.18 per bbl for the prior quarter. Realized crude oil prices in the North Sea during the third 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 decreased 3% to average $67.37 per bbl for the nine months ended September 30, 2007 from $69.58 per bbl for the nine months ended September 30, 2006. Realized crude oil prices in the third quarter of 2007 averaged $70.52 per bbl, comparable to $70.59 per bbl for the third quarter of 2006, and decreased 3% from $72.84 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, as well as the terms of the related sales contracts. Realized crude oil prices in Offshore West Africa during the third 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)	**Sep 30 2007**	Jun 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	**260,648**	350,499	910,796
Offshore West Africa, related to timing of liftings	**587,486**	813,701	113,774
	1,945,660	2,261,726	2,122,096

In the third quarter of 2007, additional net sales of approximately 316,000 barrels of crude oil produced in the Company's international operations, which were deferred and included in inventory at June 30, 2007, were sold in the third quarter, increasing cash flow from operations by approximately $19 million.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2007	Jun 30 2007	Sep 30 2006	**Sep 30 2007**	Sep 30 2006
Crude oil and NGLs (bbl/d)					
North America	**252,095**	240,420	233,440	**243,388**	230,430
North Sea	**52,013**	57,286	53,988	**57,020**	59,473
Offshore West Africa	**28,954**	29,788	34,237	**28,800**	38,150
	333,062	327,494	321,665	**329,208**	328,053
Natural gas (mmcf/d)					
North America	**1,622**	1,696	1,416	**1,670**	1,425
North Sea	**10**	15	11	**13**	15
Offshore West Africa	**15**	11	10	**12**	9
	1,647	1,722	1,437	**1,695**	1,449
Total barrel of oil equivalent (boe/d)	**607,484**	614,461	561,152	**611,665**	569,590
Product mix					
Light/medium crude oil and NGLs	**22%**	23%	24%	**23%**	26%
Pelican Lake crude oil	**6%**	6%	5%	**6%**	5%
Primary heavy crude oil	**16%**	15%	16%	**15%**	16%
Thermal heavy crude oil	**11%**	9%	12%	**10%**	11%
Natural gas	**45%**	47%	43%	**46%**	42%

DAILY PRODUCTION, net of royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2007	Jun 30 2007	Sep 30 2006	**Sep 30 2007**	Sep 30 2006
Crude oil and NGLs (bbl/d)					
North America	**213,680**	206,927	205,087	**208,370**	201,214
North Sea	**51,917**	57,185	53,911	**56,916**	59,361
Offshore West Africa	**26,158**	26,876	31,864	**26,311**	36,693
	291,755	290,988	290,862	**291,597**	297,268
Natural gas (mmcf/d)					
North America	**1,373**	1,444	1,144	**1,395**	1,149
North Sea	**10**	15	11	**13**	15
Offshore West Africa	**14**	10	9	**11**	9
	1,397	1,469	1,164	**1,419**	1,173
Total barrel of oil equivalent (boe/d)	**524,417**	535,789	484,872	**527,982**	492,759

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 611,665 boe/d for the nine months ended September 30, 2007, a 7% increase from the nine months ended September 30, 2006. Third quarter total production in 2007 averaged 607,484 boe/d, an increase of 8% from 561,152 boe/d for the third quarter of 2006, and a decrease of 1% from 614,461 boe/d for the prior quarter.

Total crude oil and NGLs production for the nine months ended September 30, 2007 increased marginally to 329,208 bbl/d from 328,053 bbl/d for the nine months ended September 30, 2006. In the third quarter of 2007, production increased 4% to 333,062 bbl/d from 321,665 bbl/d in the third quarter of 2006 and increased 2% from 327,494 bbl/d for the prior quarter. The increase from the comparable periods of 2006 was primarily due to increased production in North America, partially offset by 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. Crude oil and NGLs production in the third quarter of 2007 was within the Company's previously issued guidance of 331,000 to 349,000 bbl/d.

Natural gas production continued to represent the Company's largest product offering in 2007, accounting for 46% of the Company's total production. Natural gas production for the nine months ended September 30, 2007 averaged 1,695 mmcf/d compared to 1,449 mmcf/d for the nine months ended September 30, 2006. In the third quarter of 2007, natural gas production averaged 1,647 mmcf/d compared to 1,437 mmcf/d for the third quarter of 2006 and 1,722 mmcf/d for the prior quarter. Natural gas production generally reflects peak production levels in the spring of each year due to a higher proportion of wells drilled during the winter months, followed by natural production declines throughout the remainder of the year. These declines are partially offset by lower productivity, shallower natural gas drilling in the summer months. The increase in natural gas production from the comparable periods in 2006 primarily reflected the ACC acquisition completed in the fourth quarter of 2006, partially offset by production declines due to the Company's strategic reduction in natural gas drilling activity. Third quarter natural gas production was within the Company's previously issued guidance of 1,632 to 1,669 mmcf/d.

Annual revised production guidance for 2007 is targeted to average between 326,000 and 334,000 bbl/d of crude oil and NGLs and between 1,664 and 1,676 mmcf/d of natural gas. Fourth quarter 2007 production guidance is targeted to average between 321,000 and 344,000 bbl/d of crude oil and NGLs and between 1,577 and 1,616 mmcf/d of natural gas.

North America

North America crude oil and NGLs production for the nine months ended September 30, 2007 increased 6% to average 243,388 bbl/d, up from 230,430 bbl/d for the nine months ended September 30, 2006. Production in the third quarter of 2007 increased 8% to average 252,095 bbl/d from 233,440 bbl/d for the third quarter of 2006, and increased 5% from 240,420 bbl/d for the prior quarter. The increase in crude oil and NGLs production from the prior periods was primarily due to the positive results from the Pelican Lake project, the cyclic nature of the Company's thermal production and the ACC acquisition.

North America natural gas production increased 17% to average 1,670 mmcf/d for the nine months ended September 30, 2007, up from 1,425 mmcf/d for the nine months ended September 30, 2006. In the third quarter of 2007, natural gas production increased 15% to 1,622 mmcf/d from 1,416 mmcf/d for the third quarter of 2006, and decreased 4% from 1,696 mmcf/d for the prior quarter. The increase in natural gas production from the comparable periods in 2006 reflected the impact of the ACC acquisition, partially offset by production declines in 2007 due to the Company's strategic decision to reduce natural gas drilling activity.

North Sea

North Sea crude oil production averaged 57,020 bbl/d for the nine months ended September 30, 2007, a decrease of 4% from 59,473 bbl/d for the nine months ended September 30, 2006. Crude oil production in the third quarter of 2007 decreased 4% to 52,013 bbl/d from 53,988 bbl/d for the third quarter of 2006 and decreased 9% from 57,286 bbl/d for the prior quarter. Production levels for the third quarter of 2007 were in line with expectations, with the decrease from the prior quarter primarily related to the planned maintenance shutdowns carried out during the quarter at Ninian, T-Block, and B-Block.

Offshore West Africa

Offshore West Africa crude oil production decreased 25% to average 28,800 bbl/d for the nine months ended September 30, 2007 from 38,150 bbl/d for the nine months ended September 30, 2006. Third quarter 2007 production decreased 15% to 28,954 bbl/d from 34,237 bbl/d for the third quarter of 2006, and decreased 3% from 29,788 bbl/d for the prior quarter. Production decreased from the comparable periods in 2006 due to continued challenges with sand and solids production at the Baobab Field where 5 production wells remain shut in. The Company has secured a deepwater rig, now targeted in 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			Nine Months Ended	
	Sep 30 2007	Jun 30 2007	Sep 30 2006	**Sep 30 2007**	Sep 30 2006
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 8.00**	$ 6.58	$ 6.79	**$ 7.02**	$ 6.13
North Sea	**$ 0.14**	$ 0.13	$ 0.11	**$ 0.13**	$ 0.13
Offshore West Africa	**$ 6.81**	$ 7.12	$ 4.89	**$ 5.90**	$ 2.74
Company average	**$ 6.65**	$ 5.46	$ 5.11	**$ 5.69**	$ 4.61
Natural gas ($/mcf) [1]					
North America	**$ 0.90**	$ 1.11	$ 1.12	**$ 1.17**	$ 1.34
North Sea	**$ -**	$ -	$ -	**$ -**	$ -
Offshore West Africa	**$ 0.51**	$ 0.59	$ 0.34	**$ 0.50**	$ 0.21
Company average	**$ 0.89**	$ 1.10	$ 1.11	**$ 1.16**	$ 1.31
Company average ($/boe) [1]	**$ 6.07**	$ 5.99	$ 5.75	**$ 6.27**	$ 5.99
Percentage of revenue [2]					
Crude oil and NGLs	**11%**	10%	8%	**10%**	8%
Natural gas	**15%**	15%	19%	**16%**	19%
Boe	**13%**	12%	11%	**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 nine months ended September 30, 2007 continue to reflect strong realized crude oil prices and the full recovery of the Company's capital investments in the Primrose North and South Fields in the third 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 nine months ended September 30, 2007, compared to 13% in 2006. Crude oil and NGLs royalties per bbl are anticipated to average approximately 14% to 16% of revenues for the year.

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

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. These combined revenues are reported as sales revenue. The Government's share of profit oil attributable to the Company's equity interest is allocated to 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 PSCs.

Royalty rates as a percentage of revenue averaged approximately 10% for the third quarter of 2007 compared to 7% for third quarter of 2006 and 10% for the prior quarter. The increase in royalty rates from the comparable period in 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 approximately 8% to 10% of revenues for the year.

PRODUCTION EXPENSE

	Three Months Ended			Nine Months Ended	
	Sep 30 2007	Jun 30 2007	Sep 30 2006	**Sep 30 2007**	Sep 30 2006
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 11.69**	$ 13.98	$ 12.05	**$ 12.87**	$ 11.58
North Sea	**$ 23.61**	$ 22.11	$ 20.28	**$ 21.23**	$ 18.41
Offshore West Africa	**$ 7.00**	$ 7.98	$ 7.97	**$ 7.90**	$ 6.53
Company average	**$ 13.13**	$ 15.01	$ 13.47	**$ 13.97**	$ 12.29
Natural gas ($/mcf) (1)					
North America	**$ 0.87**	$ 0.87	$ 0.83	**$ 0.90**	$ 0.80
North Sea	**$ 2.29**	$ 2.26	$ 1.30	**$ 2.39**	$ 1.35
Offshore West Africa	**$ 1.39**	$ 1.10	$ 1.39	**$ 1.32**	$ 0.92
Company average	**$ 0.88**	$ 0.89	$ 0.84	**$ 0.91**	$ 0.81
Company average ($/boe) (1)	**$ 9.62**	$ 10.44	$ 10.01	**$ 10.05**	$ 9.13

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

North America

North America crude oil and NGLs production expense for the nine months ended September 30, 2007 increased to $12.87 per bbl from $11.58 per bbl for the nine months ended September 30, 2006. In the third quarter of 2007 production costs decreased to $11.69 per bbl from $12.05 per bbl for the third quarter of 2006 and from $13.98 per bbl for the prior quarter. Third quarter production expense per barrel primarily reflects stabilization of industry-wide cost pressures, lower cost of natural gas for fuel for the Company's thermal operations, and higher production volumes in Pelican and thermal production areas, where a large portion of costs are fixed in nature.

North America natural gas production expense per mcf in 2007 increased over the comparable periods in 2006 primarily due to industry-wide cost pressures in 2006 and early 2007. Third quarter production expense was comparable to the prior quarter as natural gas well servicing costs in Canada began to stabilize in the second and third quarters due to decreased industry activity.

North Sea

North Sea crude oil production expense varied on a per barrel basis from the comparable periods due to planned maintenance shutdowns, varying production volumes on a relatively fixed cost base and the timing of liftings from various fields.

Offshore West Africa

Offshore West Africa crude oil production expense on a per barrel basis varied from the comparable periods primarily due to the impact of continuing operating challenges with sand and solids at Baobab, resulting in decreased production volumes on a relatively fixed operating cost base, and the timing of maintenance efforts.

MIDSTREAM

($ millions)	Three Months Ended Sep 30 2007	Jun 30 2007	Sep 30 2006	Nine Months Ended Sep 30 2007	Sep 30 2006
Revenue	**$ 19**	$ 17	$ 19	**$ 55**	$ 54
Production expense	**5**	5	6	**16**	17
Midstream cash flow	**14**	12	13	**39**	37
Depreciation	**2**	2	2	**6**	6
Segment earnings before taxes	**$ 12**	$ 10	$ 11	**$ 33**	$ 31

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 Sep 30 2007	Jun 30 2007	Sep 30 2006	Nine Months Ended Sep 30 2007	Sep 30 2006
Expense ($ millions)	**$ 713**	$ 718	$ 587	**$ 2,138**	$ 1,661
$/boe (2)	**$ 12.68**	$ 12.95	$ 10.89	**$ 12.79**	$ 10.71

(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 nine and three months ended September 30, 2007 increased in total and on a boe basis from the comparable periods in 2006 and was consistent with the prior quarter. 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, a higher depletion base related to the ACC acquisition, and increased estimated future costs to develop the Company's proved undeveloped reserves, together with the impact of higher sales volumes.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three Months Ended Sep 30 2007	Jun 30 2007	Sep 30 2006	Nine Months Ended Sep 30 2007	Sep 30 2006
Expense ($ millions)	**$ 18**	$ 17	$ 17	**$ 53**	$ 50
$/boe (1)	**$ 0.32**	$ 0.30	$ 0.31	**$ 0.32**	$ 0.32

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

Asset retirement obligation accretion expense is the increase in the carrying amount of the asset retirement obligation due to the passage of time. Accretion expense for the third quarter of 2007 was consistent with the comparable periods.

ADMINISTRATION EXPENSE

	Three Months Ended			Nine Months Ended	
	Sep 30 2007	Jun 30 2007	Sep 30 2006	**Sep 30 2007**	Sep 30 2006
Net expense ($ millions)	**$ 53**	$ 53	$ 41	**$ 166**	$ 123
$/boe (1)	**$ 0.94**	$ 0.96	$ 0.76	**$ 0.99**	$ 0.79

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

Administration expense for the nine and three months ended September 30, 2007 increased in total and on a boe basis from the comparable periods in 2006 primarily due to increased staffing costs, including costs related to the Company's share bonus program. Administration expense was consistent with the prior quarter in 2007.

STOCK-BASED COMPENSATION EXPENSE (RECOVERY)

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2007**	Jun 30 2007	Sep 30 2006	**Sep 30 2007**	Sep 30 2006
Stock option plan expense (recovery)	**$ 78**	$ 106	$ (135)	**$ 209**	$ (37)

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 $209 million ($145 million after-tax) stock-based compensation expense as a result of the 22% increase in the Company's share price in the nine months ended September 30, 2007, and a $78 million ($54 million after-tax) stock-based compensation expense as a result of the 7% increase in the Company's share price for the three months ended September 30, 2007 (Company's share price as at: September 30, 2007 – C$75.56; June 30, 2007 – C$70.78; December 31, 2006 – C$62.15; September 30, 2006 – C$50.94). 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 nine months ended September 30, 2007, the Company capitalized $63 million in stock-based compensation on the Horizon Project (September 30, 2006 - $38 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 September 30, 2007. In periods when substantial stock price changes occur, the Company is subject to significant earnings volatility.

For the nine months ended September 30, 2007, the Company paid $321 million for stock options surrendered for cash settlement (September 30, 2006 - $216 million).

INTEREST EXPENSE

($ millions, except per boe amounts)	Three Months Ended Sep 30 2007	Jun 30 2007	Sep 30 2006	Nine Months Ended Sep 30 2007	Sep 30 2006
Interest expense, gross	**$ 160**	$ 158	$ 81	**$ 472**	$ 208
Less: capitalized interest, Horizon Project	**95**	81	56	**247**	130
Interest expense, net	**$ 65**	$ 77	$ 25	**$ 225**	$ 78
$/boe (1)	**$ 1.15**	$ 1.40	$ 0.48	**$ 1.34**	$ 0.51
Average effective interest rate	**5.7%**	5.4%	5.8%	**5.4%**	5.8%

(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 and the financing of Horizon Project capital expenditures.

The Company's average effective interest rate for the periods ended September 30, 2007 reflected the impact of the stronger Canadian dollar, offset by higher cost US dollar denominated debt issued in March 2007 and the impact on the Company's floating rate debt of increased short term lending rates due to credit market uncertainty.

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 interest rate 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 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 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 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 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.

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.

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 Sep 30 2007	Jun 30 2007	Sep 30 2006	Nine Months Ended Sep 30 2007	Sep 30 2006
Realized loss (gain)					
Crude oil and NGLs financial instruments	**$ 102**	$ 100	$ 419	**$ 197**	$ 1,172
Natural gas financial instruments	**(125)**	(8)	(15)	**(216)**	27
	$ (23)	$ 92	$ 404	**$ (19)**	$ 1,199
Unrealized loss (gain)					
Crude oil and NGLs financial instruments	**$ 80**	$ 64	$ (601)	**$ 474**	$ (497)
Natural gas financial instruments	**(4)**	(121)	(152)	**81**	(268)
Interest rate swaps	**-**	-	(1)	**-**	(7)
	$ 76	$ (57)	$ (754)	**$ 555**	$ (772)
Total	**$ 53**	$ 35	$ (350)	**$ 536**	$ 427

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 Sep 30 2007	Jun 30 2007	Sep 30 2006	Nine Months Ended Sep 30 2007	Sep 30 2006
Crude oil and NGLs ($/bbl) (1)	**$ 3.30**	$ 3.41	$ 13.15	**$ 2.19**	$ 13.15
Natural gas ($/mcf) (1)	**$ (0.83)**	$ (0.05)	$ (0.11)	**$ (0.47)**	$ 0.06

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

Complete details related to outstanding derivative financial instruments at September 30, 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 derivative financial instruments entered into by the Company 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 September 30, 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 $555 million ($384 million after-tax) on its commodity risk management activities for the nine months ended September 30, 2007, including a $76 million ($57 million after-tax) unrealized loss for the three months ended September 30, 2007 (June 30, 2007 – unrealized gain of $57 million, $35 million after-tax; September 30, 2006 - unrealized gain of $754 million, $496 million after-tax).

FOREIGN EXCHANGE

($ millions)	Three Months Ended Sep 30 2007	Jun 30 2007	Sep 30 2006	Nine Months Ended Sep 30 2007	Sep 30 2006
Net realized foreign exchange loss	**$ 22**	$ 26	$ 1	**$ 53**	$ 8
Net unrealized foreign exchange (gain) loss [1]	**(195)**	(250)	11	**(477)**	(37)
	$ (173)	$ (224)	$ 12	**$ (424)**	$ (29)

(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 are subject to foreign currency fluctuations due to changes in the exchange rate of the UK pound sterling to the US dollar on North Sea operations. 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 realized foreign exchange loss for the three and nine months ended September 30, 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 net unrealized foreign exchange gain for the three and nine months ended September 30, 2007 was primarily related to the second and third quarter strengthening of the Canadian dollar in relation to the US dollar with respect to the US dollar debt and 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 nine months ended September 30, 2007 was an unrealized loss of $335 million (June 30, 2007 – unrealized loss of $207 million) related to the impact of the cross currency interest rate swaps. The Canadian dollar ended the third quarter at a 31 year high, closing above parity at US$1.0037 compared to US$0.9404 at June 30, 2007 (September 30, 2006 - US$0.8966).

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.

TAXES

($ millions, except income tax rates)	Three Months Ended **Sep 30 2007**	Jun 30 2007	Sep 30 2006	Nine Months Ended **Sep 30 2007**	Sep 30 2006
Taxes other than income tax					
Current	**$ 30**	$ 9	$ 81	**$ 105**	$ 175
Deferred	**10**	20	(4)	**27**	40
	$ 40	$ 29	$ 77	**$ 132**	$ 215
Current income tax					
North America	**$ 28**	$ 12	$ 52	**$ 65**	$ 92
North Sea	**56**	54	-	**145**	-
Offshore West Africa	**21**	16	6	**47**	35
	$ 105	$ 82	$ 58	**$ 257**	$ 127
Future income tax expense	**$ 175**	$ 116	$ 473	**$ 391**	$ 517
Effective income tax rate	**28.6%**	19.1%(1)	32.2%(4)	**26.4%(1)**	22.6%(2)(3)(4)

(1) 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.

(2) Includes the effect of a one time charge 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.

(3) Includes the effect of a one time recovery of $438 million due to Canadian Federal, Alberta and Saskatchewan tax rate reductions enacted during the second quarter of 2006.

(4) Includes the effect of 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 2007 and 2008 will be sensitive to the timing of the Horizon Project capital expenditures being classified as available for use for Canadian income tax purposes.

During the nine months ended September 30, 2007, the Company's consolidated effective income tax rate was primarily reduced due to the effects of the non-taxable portion of unrealized foreign exchange gains on US dollar debt and an income tax rate reduction enacted during the second quarter of 2007.

CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended **Sep 30 2007**	Jun 30 2007	Sep 30 2006	Nine Months Ended **Sep 30 2007**	Sep 30 2006
Expenditures on property, plant and equipment					
Net property acquisitions (dispositions)	**$ 7**	$ 15	$ (6)	**$ 68**	$ 13
Land acquisition and retention	**29**	22	29	**80**	182
Seismic evaluations	**23**	34	26	**107**	113
Well drilling, completion and equipping	**299**	288	524	**1,301**	1,878
Pipeline and production facilities	**238**	243	270	**815**	1,003
Total net reserve replacement expenditures	**596**	602	843	**2,371**	3,189
Horizon Project:					
Phase 1 construction costs	**671**	704	727	**2,049**	2,023
Phases 2 and 3 costs	**28**	19	18	**91**	25
Capitalized interest, stock-based compensation and other	**120**	118	39	**329**	204
Total Horizon Project	**819**	841	784	**2,469**	2,252
Midstream	**2**	-	2	**4**	11
Abandonments [2]	**22**	13	24	**55**	56
Head office	**3**	4	8	**12**	20
Total net capital expenditures	**$ 1,442**	$ 1,460	$ 1,661	**$ 4,911**	$ 5,528
By segment					
North America	**$ 441**	$ 419	$ 667	**$ 1,858**	$ 2,640
North Sea	**121**	136	148	**395**	435
Offshore West Africa	**34**	46	27	**116**	104
Other	**-**	1	1	**2**	10
Horizon Project	**819**	841	784	**2,469**	2,252
Midstream	**2**	-	2	**4**	11
Abandonments [2]	**22**	13	24	**55**	56
Head office	**3**	4	8	**12**	20
Total	**$ 1,442**	$ 1,460	$ 1,661	**$ 4,911**	$ 5,528

(1) The net capital expenditures do not include 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 in the nine months ended September 30, 2007 were $4,911 million compared to $5,528 million in the nine months ended September 30, 2006. The capital expenditures reflected the continued progress on the Company's larger, future growth projects, most notably the Horizon Project, as well as overall industry-wide inflationary pressures, offset by the effects of an overall strategic reduction in the North America natural gas drilling program.

In the nine months ended September 30, 2007, the Company drilled a total of 1,051 net wells consisting of 303 natural gas wells, 423 crude oil wells, 248 stratigraphic test and service wells and 77 wells that were dry. This compared to 1,407 net wells drilled in the nine months ended September 30, 2006. The Company achieved an overall success rate of 90% for the nine months ended September 30, 2007, excluding stratigraphic test and service wells, compared to 92% for the nine months ended September 30, 2006**.**

Net capital expenditures in the third quarter of 2007 were $1,442 million compared to $1,661 million in the third quarter of 2006 and $1,460 million in the prior quarter. Third quarter 2007 capital expenditures decreased from the comparable period in 2006 due to the Company's strategic reduction in natural gas drilling activity, and were comparable to the second quarter of 2007.

In the third quarter of 2007, the Company drilled a total of 268 net wells consisting of 96 natural gas wells, 152 crude oil wells, 7 stratigraphic test and service wells and 13 wells that were dry. This compared to 376 net wells in the third quarter of 2006 and 95 net wells in the prior quarter. The Company achieved an overall success rate of 95% for the third quarter of 2007, excluding stratigraphic test and service wells, compared to 94% for the third quarter of 2006 and 95% for the second quarter of 2007**.**

North America

North America, including the Horizon Project, accounted for approximately 90% of the total capital expenditures for both the nine months ended September 30, 2007 and 2006.

During the nine months ended September 30, 2007, the Company targeted 358 net natural gas wells, including 52 wells in Northeast British Columbia, 126 wells in the Northern Plains region, 90 wells in Northwest Alberta, and 90 wells in the Southern Plains region. The Company also targeted 438 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 260 heavy crude oil wells, 109 Pelican Lake crude oil wells, 44 thermal crude oil wells and 5 light crude oil wells were drilled. Another 20 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. With the Company's focus on drilling crude oil wells in the first nine months of 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 the first nine months of 2007, the Company drilled 133 stratigraphic test wells and observation wells, 2 water source wells and 44 thermal oil wells. Overall Primrose thermal production for the nine months ended September 30, 2007 and 2006 was approximately 60,000 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. 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 will be impacted by the terms of the proposed changes to the Alberta royalty regime and environmental regulations, and their associated costs.

Development of new pads and secondary recovery conversion projects at Pelican Lake continued as expected throughout the third quarter of 2007. Drilling consisted of 34 horizontal wells, with plans to drill 13 additional horizontal wells for the remainder of 2007. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 35,000 bbl/d for the third quarter of 2007 compared to 30,000 bbl/d for the third quarter of 2006 and 34,000 bbl/d for the prior period.

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.

In the fourth quarter of 2007, the Company's overall drilling activity in North America is expected to be comprised of 63 natural gas wells and 120 crude oil wells excluding stratigraphic and service wells.

Horizon Project

Work progress on the Horizon Project was 84% complete at the end of the third quarter. First production continues to be targeted to commence in the third quarter of 2008. The project status as at September 30, 2007 was as follows:

- Overall detailed engineering 98% complete and substantially complete in most areas;
- Procurement 98% complete with over $5.5 billion in purchase orders and contracts awarded;
- Overall construction progress is 76% complete;
- Mine overburden removal approximately 63% complete and slightly ahead of schedule;
- Energized Main Electrical Substations;
- Completed construction of Raw Water Pond;
- Started pre-commissioning activities in Bitumen Production Areas;
- Froth tank completed and hydro-tested;
- Commenced extraction plant hydro-testing;
- Permanent power energized in R1/R2 corridors pumphouses; and
- Started commissioning of Recycle Water Pond.

Major activities for the fourth quarter of 2007 will include:

- Complete the closure of Dyke 10 (external tailings pond) in Mining;
- Complete erection of Crushing Plants and conveyors in Ore Preparation Area;
- Complete Primary Separation Cells in Extraction;
- Complete Main Control Room and Distributed Control Systems installation; and
- Complete construction of Main Laboratory.

In 2005, the Board of Directors of the Company approved the construction costs for Phase 1 of the Horizon Project, with an approved budget of $6.8 billion. Cumulative construction spending to September 30, 2007 was approximately $6.1 billion. Final construction costs for Phase 1 are expected to exceed the approved budget by approximately 8% to 14% primarily due to inflationary cost pressures.

North Sea

In the third quarter of 2007, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During the quarter, 1.0 net crude oil well was drilled along with 0.9 net water injectors, with no additional net wells drilling at the end of the quarter.

The development of the Lyell Field continued during the third quarter with the second production well coming onstream through the existing infrastructure. Production from the initial Lyell producing wells has been below expectations and continued development of the Lyell Field is under review.

Commissioning of the Columba E Raw Water Injection project was completed in the second quarter of 2007 and 2 water injection wells were delivered, allowing water injection into the reservoir to commence.

During the third quarter of 2007, the subsea project to bring gas lift to the Kyle Field was successfully completed, allowing production potential to be increased.

In August 2007, the Company entered into a Sale and Purchase Agreement for the disposal, subject to government and partner consents, of its entire working interest in the B-Block. Closing of the sale is expected during the fourth quarter of 2007 or early in 2008.

Offshore West Africa

During the third 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 third quarter of 2007. West Espoir development drilling is expected to continue into 2008 with producers and injectors being brought on line as they are completed.

During the third quarter of 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 quarter. Production volumes will not be significantly impacted during the installation work, scheduled to commence in late 2009.

At the 90% owned and operated Olowi Field in offshore Gabon, all major construction contracts have been awarded. The project is on schedule with drilling targeted to commence in the second quarter of 2008 and first crude oil is targeted in late 2008 or early 2009. Olowi production is targeted to plateau at approximately 20,000 bbl/d.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Sep 30 2007**		Jun 30 2007		Dec 31 2006		Sep 30 2006
Working capital deficit (1)	**$**	**824**	$	860	$	832	$	1,032
Long-term debt (2)	**$**	**10,686**	$	10,958	$	11,043	$	5,500
Shareholders' equity								
Share capital	**$**	**2,663**	$	2,649	$	2,562	$	2,536
Retained earnings		**9,824**		9,169		8,141		7,869
Accumulated other comprehensive income (loss)		**85**		62		(13)		(12)
Total	**$**	**12,572**	$	11,880	$	10,690	$	10,393
Debt to book capitalization (2) (3)		**45.9%**		48.0%		50.8%		34.6%
Debt to market capitalization (2)		**20.8%**		22.3%		24.8%		16.7%
After tax return on average common shareholders' equity (4)		**18.8%**		23.8%		26.9%		38.2%
After tax return on average capital employed (2) (5)		**10.9%**		13.9%		17.2%		26.0%

(1) Calculated as current assets less current liabilities.

(2) Long-term debt at September 30, 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 current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.

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

(5) Calculated as net earnings plus after-tax interest expense for the twelve month trailing period; as a percentage of average capital employed for the period. Average capital employed is the average shareholders' equity and current and long-term debt for the period, including capital related to the Horizon Project.

The Company's capital resources at September 30, 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 five- and ten-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.

At September 30, 2007, the Company had undrawn bank lines of credit of $1,309 million. Details related to the Company's long-term debt at September 30, 2007 are disclosed in note 4 to the Company's unaudited interim consolidated financial statements.

At September 30, 2007, the Company's working capital deficit was $824 million and included the current portion of the stock-based compensation liability of $435 million and the current portion of the net mark-to-market liability for risk management derivative financial instruments of $223 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 September 30, 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. Existing proved development projects, which have largely been funded prior to September 30, 2007, such as Baobab, Primrose and Espoir, and the acquisition of ACC, are anticipated to provide identified growth in production volumes in 2007 through 2009, and generate incremental free cash flows during this period.

Including the additional debt issued to complete the ACC acquisition in the fourth quarter of 2006, long-term debt was $10,686 million at September 30, 2007, resulting in a debt to book capitalization level of 45.9% (June 30, 2007 – 48.0%; December 31, 2006 – 50.8%; September 30, 2006 –34.6%). While this ratio is above 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 its balance sheet has the strength and flexibility to complete Phase 1 of the Horizon Project and its planned capital expenditure programs, the Company has hedged a significant portion of its crude oil and natural gas production for 2007 and 2008 at prices that protect investment returns. In the future, the Company may also consider the divestiture of 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 expenditure program 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 60% of expected crude oil volumes and approximately 60% of expected natural gas volumes are hedged for the remainder of 2007.

The Company has the following commodity related net financial derivatives outstanding as at September 30, 2007:

	Remaining term			Volume	Average price			Index
Crude oil								
Crude oil price collars	Oct 2007	–	Dec 2007	15,000 bbl/d	US$50.00	–	US$66.25	Mayan Heavy
	Oct 2007	–	Dec 2007	50,000 bbl/d	US$60.00	–	US$71.49	WTI
	Oct 2007	–	Dec 2007	100,000 bbl/d	US$60.00	–	US$78.11	WTI
	Oct 2007	–	Dec 2007	50,000 bbl/d	US$65.00	–	US$84.52	WTI
	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
	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	Oct 2007	–	Dec 2007	100,000 bbl/d			US$45.00	WTI
	Oct 2007	–	Dec 2007	77,000 bbl/d			US$60.00	WTI
	Jan 2008	–	Dec 2008	50,000 bbl/d			US$55.00	WTI
Brent differential swaps	Oct 2007	–	Dec 2007	50,000 bbl/d			US$1.34	WTI/Dated Brent

Natural gas								
AECO collars	Oct 2007	–	Dec 2007	60,000 GJ/d	C$8.00	–	C$8.79	AECO
	Oct 2007	–	Oct 2007	500,000 GJ/d	C$6.00	–	C$10.13	AECO
	Oct 2007	–	Oct 2007	500,000 GJ/d	C$7.00	–	C$8.24	AECO
	Nov 2007	–	Mar 2008	400,000 GJ/d	C$7.00	–	C$14.08	AECO
	Nov 2007	–	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 September 30, 2007, the Company had in place unsecured bank credit facilities of $6,210 million, comprised of:

- a $100 million demand credit facility;
- a 3-year non-revolving syndicated credit facility of $2,350 million;
- a 5-year revolving syndicated credit facility of $2,230 million;
- a 5-year revolving syndicated credit facility of $1,500 million; and
- a £15 million demand credit facility related to the Company's North Sea operations.

During the second quarter of 2007, one of the 5-year revolving syndicated credit facilities was increased 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, three-year 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 September 30, 2007.

Medium-term notes

In September 2007, the Company filed a short form shelf prospectus that allows for the issue of up to $3,000 million 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 September 2007, the Company filed a short form prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

In March 2007, the Company issued US$2,200 million of unsecured notes under a previous US shelf prospectus, 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 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.

Share capital

As at September 30, 2007, there were 539,584,000 common shares outstanding and 26,056,000 stock options outstanding. As at October 30, 2007, the Company had 539,612,000 common shares outstanding and 25,539,000 stock options outstanding.

In January 2007, the Company renewed its Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the 12-month period beginning January 24, 2007 and ending January 23, 2008, up to 26,941,730 common shares or 5% of the outstanding common shares of the Company then outstanding on the date of the announcement. As at October 30, 2007, the Company had not purchased any shares during 2007 under the Normal Course Issuer Bid.

In March 2007, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.34 per common share for 2007. The increase represents a 13% increase from the prior year, recognizes the stability of the Company's cash flow, and provides a return to Shareholders. This is the seventh consecutive year in which the Company has paid dividends and the sixth 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.

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 office space and offshore FPSOs and drilling rigs, and firm commitments for gathering, processing and transmission services, as well as expenditures relating to asset retirement obligations. As at September 30, 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 September 30, 2007:

($ millions)	Remaining 2007	2008	2009	2010	2011	Thereafter
Product transportation and pipeline	$ 53	$ 217	$ 146	$ 133	$ 106	$ 1,053
Offshore equipment operating lease (1)	$ 42	$ 94	$ 131	$ 114	$ 112	$ 481
Offshore drilling (2) (3)	$ 20	$ 303	$ 186	$ 54	$ 14	$ 2
Asset retirement obligations (4)	$ 1	$ 3	$ 3	$ 4	$ 4	$ 4,325
Long-term debt (5)	$ -	$ 39	$ 2,360	$ -	$ 399	$ 5,483
Office lease	$ 6	$ 27	$ 27	$ 27	$ 21	$ -
Electricity and other	$ 50	$ 157	$ 165	$ 18	$ 1	$ -

(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$419 million have been included in this table for the period 2007 – 2011.

(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 2007 – 2011 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 do not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $2,494 million of revolving bank credit facilities due to the extendable nature of the facilities.

In 2005, the Board of Directors of the Company approved the construction costs for Phase 1 of the Horizon Project, with an approved budget of $6.8 billion. Cumulative construction spending to September 30, 2007 was approximately $6.1 billion. Final construction costs for Phase 1 are expected to exceed the approved budget by 8% to 14%.

Legal proceedings

The Company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The Company believes that any liabilities that might arise pertaining to 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 31 of this MD&A and note 2 of the unaudited interim consolidated financial statements as at September 30, 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 third 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	$ 94	$ 0.18	$ 69	$ 0.13
Including financial derivatives	$ 72 - 88	$ 0.13 - 0.16	$ 53 - 64	$ 0.10 - 0.12
Natural gas – AECO C$0.10/mcf (1)				
Excluding financial derivatives	$ 43	$ 0.08	$ 30	$ 0.06
Including financial derivatives	$ 26	$ 0.05	$ 18	$ 0.03
Volume changes				
Crude oil – 10,000 bbl/d	$ 127	$ 0.23	$ 65	$ 0.12
Natural gas – 10 mmcf/d	$ 15	$ 0.03	$ 5	$ 0.01
Foreign currency rate change				
$0.01 change in US$ (1)				
Including financial derivatives	$ 79 - 81	$ 0.15	$ 29 - 30	$ 0.05 - 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

($/boe) [1]	Three Months Ended Sep 30 2007	Jun 30 2007	Sep 30 2006	Nine Months Ended Sep 30 2007	Sep 30 2006
Sales price [2]	**$ 47.96**	$ 49.70	$ 51.21	**$ 48.99**	$ 49.38
Royalties	**6.07**	5.99	5.75	**6.27**	5.99
Production expense [3]	**9.62**	10.44	10.01	**10.05**	9.13
Netback	**32.27**	33.27	35.45	**32.67**	34.26
Midstream contribution [3]	**(0.26)**	(0.20)	(0.23)	**(0.23)**	(0.24)
Administration	**0.94**	0.96	0.76	**0.99**	0.79
Interest, net	**1.15**	1.40	0.48	**1.34**	0.51
Realized risk management (gain) loss	**(0.41)**	1.66	7.51	**(0.11)**	7.73
Realized foreign exchange loss	**0.38**	0.47	0.01	**0.31**	0.05
Taxes other than income tax - current	**0.54**	0.16	1.50	**0.62**	1.13
Current income tax - North America	**0.49**	0.21	0.97	**0.38**	0.60
Current income tax - North Sea	**0.99**	0.99	-	**0.87**	-
Current income tax - Offshore West Africa	**0.37**	0.29	0.11	**0.28**	0.22
Cash flow	**$ 28.08**	$ 27.33	$ 24.34	**$ 28.22**	$ 23.47

(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)	**Sep 30 2007**	Dec 31 2006
ASSETS		
Current assets		
Cash and cash equivalents	**$ 21**	$ 23
Accounts receivable and other	**1,787**	1,947
Future income tax	**204**	163
Current portion of other long-term assets (note 3)	**36**	106
	2,048	2,239
Property, plant and equipment (note 12)	**33,191**	30,767
Other long-term assets (note 3)	**43**	154
	$ 35,282	$ 33,160
LIABILITIES		
Current liabilities		
Accounts payable	**$ 629**	$ 842
Accrued liabilities	**1,585**	1,618
Current portion of other long-term liabilities (note 5)	**658**	611
	2,872	3,071
Long-term debt (note 4)	**10,686**	11,043
Other long-term liabilities (note 5)	**1,767**	1,393
Future income tax	**7,385**	6,963
	22,710	22,470
SHAREHOLDERS' EQUITY		
Share capital (note 7)	**2,663**	2,562
Retained earnings	**9,824**	8,141
Accumulated other comprehensive income (loss) (note 8)	**85**	(13)
	12,572	10,690
	$ 35,282	$ 33,160

Commitments (note 11)

Consolidated statements of earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended Sep 30 2007	Sep 30 2006	Nine Months Ended Sep 30 2007	Sep 30 2006
Revenue	**$ 3,073**	$ 3,108	**$ 9,343**	$ 8,817
Less: royalties	**(341)**	(310)	**(1,048)**	(928)
Revenue, net of royalties	**2,732**	2,798	**8,295**	7,889
Expenses				
Production	**544**	544	**1,693**	1,430
Transportation and blending	**359**	331	**1,103**	1,110
Depletion, depreciation and amortization	**715**	589	**2,144**	1,667
Asset retirement obligation accretion (note 5)	**18**	17	**53**	50
Administration	**53**	41	**166**	123
Stock-based compensation expense (recovery) (note 5)	**78**	(135)	**209**	(37)
Interest, net	**65**	25	**225**	78
Risk management activities (note 10)	**53**	(350)	**536**	427
Foreign exchange (gain) loss	**(173)**	12	**(424)**	(29)
	1,712	1,074	**5,705**	4,819
Earnings before taxes	**1,020**	1,724	**2,590**	3,070
Taxes other than income tax	**40**	77	**132**	215
Current income tax expense (note 6)	**105**	58	**257**	127
Future income tax expense (note 6)	**175**	473	**391**	517
Net earnings	**$ 700**	$ 1,116	**$ 1,810**	$ 2,211
Net earnings per common share (note 9)				
Basic and diluted	**$ 1.30**	$ 2.08	**$ 3.36**	$ 4.12

Consolidated statements of shareholders' equity

(millions of Canadian dollars, unaudited)	Nine Months Ended Sep 30 2007	Nine Months Ended Sep 30 2006
Common shares		
Balance – beginning of period	**$ 2,562**	$ 2,442
Issued upon exercise of stock options	**19**	17
Previously recognized liability on stock options exercised for common shares	**82**	79
Purchase of common shares under Normal Course Issuer Bid	**-**	(2)
Balance – end of period	**2,663**	2,536
Retained earnings		
Balance – beginning of period, as originally reported	**8,141**	5,804
Transition adjustment on adoption of financial instruments standards (note 2)	**10**	-
Balance – beginning of period, as restated	**8,151**	5,804
Net earnings	**1,810**	2,211
Dividends on common shares (note 7)	**(137)**	(120)
Purchase of common shares under Normal Course Issuer Bid	**-**	(26)
Balance – end of period	**9,824**	7,869
Accumulated other comprehensive income (loss) (note 2)		
Balance – beginning of period	**(13)**	(9)
Transition adjustment on adoption of financial instruments standards	**159**	-
Balance – beginning of period, after effect of transition adjustment	**146**	(9)
Other comprehensive loss, net of taxes	**(61)**	(3)
Balance – end of period	**85**	(12)
Shareholders' equity	**$ 12,572**	$ 10,393

Consolidated statements of comprehensive income

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2007	Three Months Ended Sep 30 2006	Nine Months Ended Sep 30 2007	Nine Months Ended Sep 30 2006
Net earnings	**$ 700**	$ 1,116	**$ 1,810**	$ 2,211
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income during the period (net of taxes of $1 million – three months ended; $9 million – nine months ended)	**10**	-	**6**	-
Reclassification to net earnings (net of taxes of $11 million – three months ended; $24 million – nine months ended)	**24**	-	**(51)**	-
	34	-	**(45)**	-
Foreign currency translation adjustment				
Translation of net investment	**(11)**	-	**(16)**	(6)
Hedge of net investment, net of tax	**-**	-	**-**	3
	(11)	-	**(16)**	(3)
Other comprehensive income (loss), net of taxes	**23**	-	**(61)**	(3)
Comprehensive income	**$ 723**	$ 1,116	**$ 1,749**	$ 2,208

Consolidated statements of cash flows

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2007	Three Months Ended Sep 30 2006	Nine Months Ended Sep 30 2007	Nine Months Ended Sep 30 2006
Operating activities				
Net earnings	**$ 700**	$ 1,116	**$ 1,810**	$ 2,211
Non-cash items				
Depletion, depreciation and amortization	**715**	589	**2,144**	1,667
Asset retirement obligation accretion	**18**	17	**53**	50
Stock-based compensation expense (recovery)	**78**	(135)	**209**	(37)
Unrealized risk management activities	**76**	(754)	**555**	(772)
Unrealized foreign exchange (gain) loss	**(195)**	11	**(477)**	(37)
Deferred petroleum revenue tax (recovery)	**10**	(4)	**27**	40
Future income tax expense	**175**	473	**391**	517
Deferred charges	**12**	-	**7**	(8)
Abandonment expenditures	**(22)**	(24)	**(55)**	(56)
Net change in non-cash working capital	**(94)**	(4)	**(82)**	(362)
	1,473	1,285	**4,582**	3,213
Financing activities				
Issue (repayment) of bankers' acceptances	**49**	(285)	**(1,797)**	1,115
(Repayment) issue of medium-term notes	**-**	-	**(125)**	400
Repayment of senior unsecured notes	**-**	-	**(33)**	-
Issue of US dollar debt securities	**-**	788	**2,553**	788
Issue of common shares on exercise of stock options	**3**	4	**19**	17
Dividends on common shares	**(46)**	(41)	**(132)**	(113)
Purchase of common shares	**-**	(6)	**-**	(28)
Net change in non-cash working capital	**(17)**	2	**6**	8
	(11)	462	**491**	2,187
Investing activities				
Expenditures on property, plant and equipment	**(1,421)**	(1,638)	**(4,861)**	(5,475)
Net proceeds on sale of property, plant and equipment	**1**	1	**5**	3
Net expenditures on property, plant and equipment	**(1,420)**	(1,637)	**(4,856)**	(5,472)
Net change in non-cash working capital	**(32)**	(113)	**(219)**	66
	(1,452)	(1,750)	**(5,075)**	(5,406)
Increase (decrease) in cash and cash equivalents	**10**	(3)	**(2)**	(6)
Cash and cash equivalents – beginning of period	**11**	15	**23**	18
Cash and cash equivalents – end of period	**$ 21**	$ 12	**$ 21**	$ 12
Interest paid	**$ 158**	$ 70	**$ 403**	$ 179
Taxes paid				
Taxes other than income tax	**$ 29**	$ 106	**$ 103**	$ 239
Current income tax	**$ 85**	$ 51	**$ 157**	$ 304

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.

Comparative figures

Certain figures relating to the presentation of gross revenues and gross transportation and blending provided for the prior year have been reclassified to conform to the presentation adopted in the fourth quarter of 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 interest rate 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.

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 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 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 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.

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.

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.

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

	Sep 30 2007	Dec 31 2006
Deferred charges (note 2)	**$ 58**	$ 109
Risk management (note 10)	**-**	128
Other	**21**	23
	79	260
Less: current portion	**36**	106
	$ 43	$ 154

4. LONG–TERM DEBT

	Sep 30 2007	Dec 31 2006
Canadian dollar denominated debt		
Bank credit facilities (bankers' acceptances)	**$ 4,824**	$ 6,621
Medium-term notes	**800**	925
	5,624	7,546
US dollar denominated debt		
Senior unsecured notes (2007 – US$62 million; and 2006 - US$93 million)	**62**	108
US dollar debt securities (2007 – US$5,108 million; and 2006 - US$2,908 million)	**5,089**	3,389
Less – original issue discount on senior unsecured notes and US dollar debt securities (1)	**(23)**	-
	5,128	3,497
Change in fair value of interest rate swaps on US dollar debt securities (2)	**(15)**	-
	5,113	3,497
Long-term debt before transaction costs	**10,737**	11,043
Less – transaction costs (1) (3)	**(51)**	-
	$ 10,686	$ 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 $15 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.

Bank credit facilities

As at September 30, 2007, the Company had in place unsecured bank credit facilities of $6,210 million, comprised of:

- a $100 million demand credit facility;
- a 3-year non-revolving syndicated credit facility of $2,350 million;
- a 5-year revolving syndicated credit facility of $2,230 million;
- a 5-year revolving syndicated credit facility of $1,500 million; and
- a £15 million demand credit facility related to the Company's North Sea operations.

During the second quarter of 2007, one of the 5-year revolving syndicated credit facilities was increased 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 Anadarko Canada Corporation in November 2006, the Company executed a $3,850 million, three-year 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 September 30, 2007, was 5.4% (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 September 30, 2007.

Medium-term notes

In September 2007, the Company filed a short form shelf prospectus that allows for the issue of up to $3,000 million 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 September 2007, the Company filed a short form prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

In March 2007, the Company issued US$2,200 million of unsecured notes under a previous US shelf prospectus, 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.

5. OTHER LONG–TERM LIABILITIES

	Sep 30 2007	Dec 31 2006
Asset retirement obligations	**$ 1,095**	$ 1,166
Stock-based compensation	**613**	744
Risk management (note 10)	**618**	-
Other	**99**	94
	2,425	2,004
Less: current portion	**658**	611
	$ 1,767	$ 1,393

Asset retirement obligations

At September 30, 2007, the Company's total estimated cost to settle its asset retirement obligations was approximately $4,340 million (December 31, 2006 - $4,497 million). These costs will be incurred over the lives of the operating assets and have been discounted using an average credit-adjusted risk free rate of 6.7%. A reconciliation of the discounted asset retirement obligations is as follows:

	Nine Months Ended Sep 30, 2007	Year Ended Dec 31, 2006
Balance – beginning of period	**$ 1,166**	$ 1,112
Liabilities incurred	**11**	26
Liabilities acquired	**-**	56
Liabilities settled	**(55)**	(75)
Asset retirement obligation accretion	**53**	68
Revision of estimates	**1**	(21)
Foreign exchange	**(81)**	-
Balance – end of period	**$ 1,095**	$ 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.

	Nine Months Ended Sep 30, 2007	Year Ended Dec 31, 2006
Balance – beginning of period	**$ 744**	$ 891
Stock-based compensation	**209**	139
Payments for options surrendered	**(321)**	(264)
Transferred to common shares	**(82)**	(101)
Capitalized to Horizon Project	**63**	79
Balance – end of period	**613**	744
Less: current portion of stock-based compensation	**435**	611
	$ 178	$ 133

6. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2007	Sep 30 2006	**Sep 30 2007**	Sep 30 2006
Current income tax – North America	**$ 28**	$ 52	**$ 65**	$ 92
Current income tax – North Sea	**56**	-	**145**	-
Current income tax – Offshore West Africa	**21**	6	**47**	35
Current income tax expense	**105**	58	**257**	127
Future income tax expense	**175**	473	**391**	517
Income tax expense	**$ 280**	$ 531	**$ 648**	$ 644

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 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, 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, 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, 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 CAPITAL

	Nine Months Ended Sep 30, 2007	
Issued **Common shares**	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**537,903**	**$ 2,562**
Issued upon exercise of stock options	**1,681**	**19**
Previously recognized liability on stock options exercised for common shares	**-**	**82**
Balance – end of period	**539,584**	**$ 2,663**

Normal Course Issuer Bid

In January 2007, the Company renewed its Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the 12-month period beginning January 24, 2007 and ending January 23, 2008, up to 26,941,730 common shares or 5% of the outstanding common shares of the Company then outstanding on the date of the announcement. As at September 30, 2007, the Company had not purchased any shares under the Normal Course Issuer Bid.

Dividend policy

In March 2007, the Board of Directors set the regular quarterly dividend at $0.085 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.

Stock options

	Nine Months Ended Sep 30, 2007	
	Stock options (thousands)	**Weighted average exercise price**
Outstanding – beginning of period	**34,425**	**$ 33.77**
Granted	**1,458**	**$ 68.36**
Exercised for common shares	**(1,681)**	**$ 11.20**
Surrendered for cash settlement	**(6,240)**	**$ 15.49**
Forfeited	**(1,906)**	**$ 45.70**
Outstanding – end of period	**26,056**	**$ 40.70**
Exercisable – end of period	**6,967**	**$ 23.96**

8. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

	Sep 30 2007	Sep 30 2006
Derivative financial instruments designated as cash flow hedges	**$ 114**	$ -
Foreign currency translation adjustment	**(29)**	(12)
Accumulated other comprehensive income (loss)	**$ 85**	$ (12)

9. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Nine Months Ended	
	Sep 30 2007	Sep 30 2006	**Sep 30 2007**	Sep 30 2006
Weighted average common shares outstanding (thousands) – basic and diluted	**539,494**	537,292	**539,229**	537,296
Net earnings – basic and diluted	**$ 700**	$ 1,116	**$ 1,810**	$ 2,211
Net earnings per common share – basic and diluted	**$ 1.30**	$ 2.08	**$ 3.36**	$ 4.12

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 financial derivatives recognized in the risk management asset (liability) were comprised as follows:

	Nine Months Ended Sep 30, 2007	Year Ended Dec 31, 2006	
Asset (liability)	**Risk management mark-to-market**	Risk management mark-to-market	Deferred revenue
Balance – beginning of period	**$ 128**	$ (877)	$ (8)
Retained earnings effect of adoption of financial instrument standards (note 2)	**14**	-	-
Net cost of outstanding put options	**129**	455	-
Net change in fair value of outstanding derivative financial instruments attributable to:			
- Risk management activities	**(555)**	995	-
- Interest expense	**(15)**	-	-
- Foreign exchange	**(335)**	10	-
- Other comprehensive income	**157**	-	-
Amortization of deferred revenue	**-**	-	8
	(477)	583	-
Add: Put premium financing obligations (1)	**(141)**	(455)	-
Balance – end of period	**(618)**	128	-
Less: current portion	**(223)**	88	-
	$ (395)	$ 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 (gains) losses from risk management activities were as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2007	Sep 30 2006	**Sep 30 2007**	Sep 30 2006
Net realized risk management (gain) loss	**$ (23)**	$ 404	**$ (19)**	$ 1,199
Net unrealized risk management mark-to-market loss (gain)	**76**	(754)	**555**	(772)
	$ 53	$ (350)	**$ 536**	$ 427

The Company had the following net financial derivatives outstanding as at September 30, 2007:

	Remaining term			Volume	Average price			Index
Crude oil								
Crude oil price collars	Oct 2007	–	Dec 2007	15,000 bbl/d	US$50.00	–	US$66.25	Mayan Heavy
	Oct 2007	–	Dec 2007	50,000 bbl/d	US$60.00	–	US$71.49	WTI
	Oct 2007	–	Dec 2007	100,000 bbl/d	US$60.00	–	US$78.11	WTI
	Oct 2007	–	Dec 2007	50,000 bbl/d	US$65.00	–	US$84.52	WTI
	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
	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	Oct 2007	–	Dec 2007	100,000 bbl/d			US$45.00	WTI
	Oct 2007	–	Dec 2007	77,000 bbl/d			US$60.00	WTI
	Jan 2008	–	Dec 2008	50,000 bbl/d			US$55.00	WTI
Brent differential swaps	Oct 2007	–	Dec 2007	50,000 bbl/d			US$1.34	WTI/Dated Brent

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

	Q4 2007	Q1 2008	Q2 2008	Q3 2008	Q4 2008
Cost ($ millions)	US$72	US$14	US$15	US$15	US$15

	Remaining term			Volume	Average price			Index
Natural gas								
AECO collars	Oct 2007	–	Dec 2007	60,000 GJ/d	C$8.00	–	C$8.79	AECO
	Oct 2007	–	Oct 2007	500,000 GJ/d	C$6.00	–	C$10.13	AECO
	Oct 2007	–	Oct 2007	500,000 GJ/d	C$7.00	–	C$8.24	AECO
	Nov 2007	–	Mar 2008	400,000 GJ/d	C$7.00	–	C$14.08	AECO
	Nov 2007	–	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.

In addition to the financial derivatives noted above, the Company also entered into natural gas physical sales contracts for 300,000 GJ/d at an average fixed price of C$7.33 per GJ at AECO for the month of October 2007.

	Remaining term			Amount ($ millions)	Fixed rate	Floating rate
Interest rate						
Swaps – fixed to floating	Oct 2007	–	Oct 2012	US$350	5.45%	LIBOR [(1)] + 0.81%
	Oct 2007	–	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	Oct 2007	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Oct 2007	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Oct 2007	–	Mar 2038	US$550	1.170	6.25%	5.76%

11. COMMITMENTS

The Company has committed to certain payments as follows:

	Remaining 2007	2008	2009	2010	2011	Thereafter
Product transportation and pipeline	$ 53	$ 217	$ 146	$ 133	$ 106	$ 1,053
Offshore equipment operating leases [(1)]	$ 42	$ 94	$ 131	$ 114	$ 112	$ 481
Offshore drilling [(2) (3)]	$ 20	$ 303	$ 186	$ 54	$ 14	$ 2
Asset retirement obligations [(4)]	$ 1	$ 3	$ 3	$ 4	$ 4	$ 4,325
Office leases	$ 6	$ 27	$ 27	$ 27	$ 21	$ -
Electricity and other	$ 50	$ 157	$ 165	$ 18	$ 1	$ -

(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$419 million have been included in this table for the period 2007 - 2011.

(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 2007 – 2011 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

In 2005, the Board of Directors of the Company approved the construction costs for Phase 1 of the Horizon Project, with an approved budget of $6.8 billion. Cumulative construction spending to September 30, 2007 was approximately $6.1 billion. Final construction costs for Phase 1 are expected to exceed the approved budget.

12. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America				North Sea				Offshore West Africa			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2007	2006	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006
Segmented revenue	**2,459**	2,301	**7,578**	6,823	**397**	567	**1,230**	1,264	**211**	236	**516**	718
Less: royalties	**(320)**	(293)	**(1,001)**	(898)	**(1)**	(1)	**(2)**	(2)	**(20)**	(16)	**(45)**	(28)
Segmented revenue, net of royalties	**2,139**	2,008	**6,577**	5,925	**396**	566	**1,228**	1,262	**191**	220	**471**	690
Segmented expenses												
Production	**401**	368	**1,265**	1,036	**117**	145	**353**	313	**23**	27	**63**	68
Transportation and blending	**366**	337	**1,122**	1,128	**4**	3	**12**	11	**-**	-	**-**	-
Depletion, depreciation and amortization	**593**	454	**1,748**	1,317	**77**	90	**271**	212	**43**	43	**119**	132
Asset retirement obligation accretion	**9**	9	**28**	26	**8**	7	**23**	22	**1**	1	**2**	2
Realized risk management activities	**(28)**	313	**(53)**	946	**5**	91	**34**	253	**-**	-	**-**	-
Total segmented expenses	**1,341**	1,481	**4,110**	4,453	**211**	336	**693**	811	**67**	71	**184**	202
Segmented earnings (loss) before the following	**798**	527	**2,467**	1,472	**185**	230	**535**	451	**124**	149	**287**	488
Non-segmented expenses												
Administration												
Stock-based compensation expense (recovery)												
Interest, net												
Unrealized risk management activities												
Foreign exchange (gain) loss												
Total non-segmented expenses												
Earnings before taxes												
Taxes other than income tax												
Current income tax expense												
Future income tax expense												
Net earnings												

(millions of Canadian dollars, unaudited)	Midstream Three Months Ended Sep 30		Midstream Nine Months Ended Sep 30		Inter-segment elimination and other Three Months Ended Sep 30		Inter-segment elimination and other Nine Months Ended Sep 30		Total Three Months Ended Sep 30		Total Nine Months Ended Sep 30	
	2007	2006	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006
Segmented revenue	**19**	19	**55**	54	**(13)**	(15)	**(36)**	(42)	**3,073**	3,108	**9,343**	8,817
Less: royalties	**-**	-	**-**	-	**-**	-	**-**	-	**(341)**	(310)	**(1,048)**	(928)
Segmented revenue, net of royalties	**19**	19	**55**	54	**(13)**	(15)	**(36)**	(42)	**2,732**	2,798	**8,295**	7,889
Segmented expenses												
Production	**5**	6	**16**	17	**(2)**	(2)	**(4)**	(4)	**544**	544	**1,693**	1,430
Transportation and blending	**-**	-	**-**	-	**(11)**	(9)	**(31)**	(29)	**359**	331	**1,103**	1,110
Depletion, depreciation and amortization	**2**	2	**6**	6	**-**	-	**-**	-	**715**	589	**2,144**	1,667
Asset retirement obligation accretion	**-**	-	**-**	-	**-**	-	**-**	-	**18**	17	**53**	50
Realized risk management activities	**-**	-	**-**	-	**-**	-	**-**	-	**(23)**	404	**(19)**	1,199
Total segmented expenses	**7**	8	**22**	23	**(13)**	(11)	**(35)**	(33)	**1,613**	1,885	**4,974**	5,456
Segmented earnings (loss) before the following	**12**	11	**33**	31	**-**	(4)	**(1)**	(9)	**1,119**	913	**3,321**	2,433
Non-segmented expenses												
Administration									**53**	41	**166**	123
Stock-based compensation expense (recovery)									**78**	(135)	**209**	(37)
Interest, net									**65**	25	**225**	78
Unrealized risk management activities									**76**	(754)	**555**	(772)
Foreign exchange (gain) loss									**(173)**	12	**(424)**	(29)
Total non-segmented expenses									**99**	(811)	**731**	(637)
Earnings before taxes									**1,020**	1,724	**2,590**	3,070
Taxes other than income tax									**40**	77	**132**	215
Current income tax expense									**105**	58	**257**	127
Future income tax expense									**175**	473	**391**	517
Net earnings									**700**	1,116	**1,810**	2,211

Net additions to property, plant and equipment

	Nine Months Ended					
	Sep 30, 2007			Sep 30, 2006		
	Net Expenditures	**Fair Value Changes (1)**	**Capitalized Costs**	Net Expenditures	Fair Value Changes (1)	Capitalized Costs
North America	**$ 1,858**	**$ 11**	**$ 1,869**	$ 2,640	$ 14	$ 2,654
North Sea	**395**	**-**	**395**	435	(1)	434
Offshore West Africa	**116**	**-**	**116**	104	12	116
Other	**2**	**-**	**2**	10	-	10
Horizon Project (2)	**2,469**	**-**	**2,469**	2,252	-	2,252
Midstream	**4**	**-**	**4**	11	-	11
Head office	**12**	**-**	**12**	20	-	20
	$ 4,856	**$ 11**	**$ 4,867**	$ 5,472	$ 25	$ 5,497

(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	
	Sep 30 2007	Dec 31 2006	**Sep 30 2007**	Dec 31 2006
Segmented assets				
North America	**$ 22,021**	$ 21,879	**$ 23,465**	$ 23,670
North Sea	**1,867**	2,029	**2,103**	2,248
Offshore West Africa	**1,184**	1,204	**1,321**	1,323
Other	**26**	24	**54**	46
Horizon Project	**7,819**	5,350	**7,946**	5,444
Midstream	**205**	207	**324**	355
Head office	**69**	74	**69**	74
	$ 33,191	$ 30,767	**$ 35,282**	$ 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 Phase 1 will cease once construction is substantially complete and this phase of the Horizon Project is available for its intended use. For the nine months ended September 30, 2007, pre-tax interest of $247 million was capitalized to the Horizon Project (September 30, 2006 - $130 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 September 30, 2007:	
Interest coverage (times)	
Net earnings (1)	5.5x
Cash flow from operations (2)	11.1x

(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.

CORPORATE INFORMATION

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Stock Listing

Toronto Stock Exchange
Trading Symbol – CNQ

New York Stock Exchange
Trading Symbol – CNQ

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