Canadian Natural

diverse asset base | disciplined growth | strong leadership

THIRD QUARTER REPORT
Nine months ended September 30, 2008

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2008 THIRD QUARTER RESULTS

Commenting on the third quarter 2008 results, Canadian Natural Resources Limited ("Canadian Natural" or the "Company")'s Chairman, Allan Markin stated, "The Company delivered strong results in the third quarter, clearly illustrating how Canadian Natural is strategically positioned to weather the ups and downs of economic uncertainty. Our fundamental approach to business does not change due to market conditions and the true strength of the Company lies in our ability to create value in both good economic times and bad. As the third quarter experienced volatile commodity pricing, our results serve as an example of how our strategy of capital allocation, balance and cost control has led us to a history of creating value for our shareholders. Canadian Natural is committed to "doing it right" for all stakeholders. We remain active participants in the communities in which we operate to ensure we conduct our business safely, to maximize economic return, and participate with communities both locally and regionally, while minimizing impact to the environment."

John Langille, Vice-Chairman of Canadian Natural continued, "Third quarter results show the discipline of Canadian Natural as cash flow from operations and capital expenditures were balanced for the quarter. Our hedging program is a reflection of our commitment to internally fund our capital projects. As such, we have added to our hedges for 2009 for both crude oil and natural gas at strong prices. Our major projects in Alberta and Offshore West Africa are either onstream or will be onstream by the first quarter of 2009 and as such, capital spending on these projects will decrease markedly. The cash flow that has been going towards these projects, along with the cash flow they will generate, will provide free cash flow which will first go towards paying down debt, further strengthening our balance sheet."

President and Chief Operating Officer, Steve Laut, commented, "Balance in our asset base provides us the ability to optimize capital allocation. These projects continue to center on heavy crude oil as a result of the favorable heavy crude oil differential and Canadian Natural's ability to execute on these projects. The Primrose East expansion, which will contribute up to 40,000 barrels per day of thermal crude oil, has come in ahead of schedule and on budget. We achieved first steam in September and the project achieved first production in October. The Olowi project in Offshore West Africa which will deliver 20,000 barrels per day of light crude oil and is targeted for first production in the first quarter of 2009. The Horizon Project is nearing completion with first synthetic crude oil targeted for late in the fourth quarter. First bitumen crude oil production was achieved in early September and since then we have produced approximately 160,000 barrels of bitumen for test purposes. The majority of the processing plants are either fully commissioned or well into commissioning, and our on-site manpower has been reduced by over 50% during the quarter. As we look forward to the imminent increase in production coming from Primrose East, the Horizon Project, Olowi, and Baobab, Canadian Natural emerges as a stronger, more diversified and robust company."

HIGHLIGHTS

($ millions, except as noted)	Three Months Ended **Sep 30 2008**	 Jun 30 2008	 Sep 30 2007	Nine Months Ended **Sep 30 2008**	 Sep 30 2007
Net earnings (loss)	**$ 2,835**	$ (347)	$ 700	**$ 3,215**	$ 1,810
per common share, basic and diluted	**$ 5.25**	$ (0.65)	$ 1.30	**$ 5.95**	$ 3.36
Adjusted net earnings from operations (1)	**$ 963**	$ 960	$ 644	**$ 2,795**	$ 1,860
per common share, basic and diluted	**$ 1.78**	$ 1.78	$ 1.19	**$ 5.17**	$ 3.44
Cash flow from operations (2)	**$ 1,815**	$ 1,859	$ 1,577	**$ 5,399**	$ 4,712
per common share, basic and diluted	**$ 3.36**	$ 3.44	$ 2.92	**$ 9.99**	$ 8.74
Capital expenditures, net of dispositions	**$ 1,744**	$ 2,127	$ 1,442	**$ 5,624**	$ 4,911
Daily production, before royalties					
Natural gas (mmcf/d)	**1,490**	1,526	1,647	**1,518**	1,695
Crude oil and NGLs (bbl/d)	**306,970**	319,077	333,062	**317,715**	329,208
Equivalent production (boe/d)	**555,356**	573,437	607,484	**570,704**	611,665

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

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

- Total crude oil and NGLs production for Q3/08 was 306,970 bbl/d. Q3/08 crude oil production volumes decreased 4% from Q2/08 of 319,077 bbl/d, and decreased 8% from Q3/07 of 333,062 bbl/d. Volumes in Q3/08 reflect the transition between steam and production cycles for Primrose thermal wells, and continued conversion of production wells to polymer injection wells at Pelican Lake, along with scheduled turnarounds in the North Sea and Offshore West Africa.

- Natural gas production volumes for the third quarter represented 45% of the Company's total production. Natural gas production for Q3/08 averaged 1,490 mmcf/d, down 2% from 1,526 mmcf/d for Q2/08 and down 10% from 1,647 mmcf/d for Q3/07. The decrease in volumes for Q3/08 from Q3/07 reflected the reallocation of capital towards higher return crude oil projects. However, the quarter once again saw a very successful North America natural gas drilling program.

- Quarterly cash flow from operations was over $1.8 billion, a 2% decrease from Q2/08 and an increase of 15% from Q3/07. The increase from Q3/07 primarily reflected higher crude oil and natural gas realizations, partially offset by higher realized risk management losses, higher royalties and lower sales volumes. The decrease from Q2/08 is primarily a result of decreased sales volumes and higher production costs, offsetting lower realized risk management losses and lower royalties.

- Quarterly net earnings for Q3/08 of $2.8 billion includes the effects of unrealized risk management activity, stock based compensation and fluctuations in foreign exchange. Excluding these items, quarterly adjusted net earnings from operations for Q3/08 were $963 million.

- Maintained a strong undeveloped conventional core land base in Canada of 11.7 million net acres - a key asset for continued value growth.

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

- The Primrose East Expansion, which is targeted to add 40,000 bbl/d of capacity, has made significant progress. First steam commenced in September of this year, coming in ahead of schedule. First production was achieved in late October 2008 versus a previous target of Q1/09.
- Drilling has started at Baobab in Offshore Côte d'Ivoire. The equipment was mobilized in early Q2/08, enabling work to begin on the restoration of shut-in production with the first well brought on stream in Q3/08. It is targeted that 3 of the 5 wells will be brought on stream over the course of 2008 and 2009.
- The Olowi Project in Offshore Gabon has experienced some delays in construction of the FPSO and first oil is now expected in Q1/09. During Q3/08, construction of the Conductor Supported Platform Deck was completed. Two appraisal wells have been drilled and development is continuing as planned.
- Construction and commissioning of the Horizon Oil Sands Project ("Horizon Project" or the "Project") continued in Q3/08 with first bitumen crude oil production for testing purposes commencing in early September. First 34º API, light sweet synthetic crude oil production ("SCO") is targeted for late Q4/08.
- Committed to ship 120,000 bbl/d of heavy crude oil for 20 years on the proposed Keystone pipeline US Gulf Coast expansion from Hardisty, Alberta to Port Arthur, Texas.
- Committed to a 100,000 bbl/d heavy crude oil supply agreement with a major US refiner to supply refineries in the Gulf Coast at market prices for 20 years.
- Declared a quarterly cash dividend on common shares of C$0.10 per common share, payable January 1, 2009.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

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

OPERATIONS REVIEW

Activity by core region

	Net undeveloped land as at Sep 30, 2008 (thousands of net acres)	Drilling activity nine months ended Sep 30, 2008 (net wells) (1)
Canadian conventional		
Northeast British Columbia	**2,284**	**24.2**
Northwest Alberta	**1,379**	**69.7**
Northern Plains	**6,563**	**479.1**
Southern Plains	**854**	**91.2**
Southeast Saskatchewan	**124**	**47.0**
In-situ Oil Sands	**497**	**72.0**
	11,701	**783.2**
Horizon Oil Sands Project	**115**	**-**
United Kingdom North Sea	**268**	**4.1**
Offshore West Africa	**207**	**3.0**
	12,291	**790.3**

(1) Drilling activity includes stratigraphic test and service wells

Drilling activity (number of wells)

	Nine Months Ended Sep 30			
	2008		2007	
	Gross	**Net**	Gross	Net
Crude oil	**529**	**500**	458	423
Natural gas	**304**	**228**	386	303
Dry	**32**	**28**	89	77
Subtotal	**865**	**756**	933	803
Stratigraphic test / service wells	**36**	**34**	250	248
Total	**901**	**790**	1,183	1,051
Success rate (excluding stratigraphic test / service wells)		**96%**		90%

North America Conventional

North America natural gas

	Three Months Ended			Nine Months Ended	
	Sep 30 2008	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Natural gas production (mmcf/d)	**1,467**	1,501	1,622	**1,494**	1,670
Net wells targeting natural gas	**62**	8	106	**237**	358
Net successful wells drilled	**62**	5	96	**228**	303
Success rate	**100%**	63%	91%	**96%**	85%

- Q3/08 North America natural gas production decreased 2% from Q2/08 and decreased 10% from Q3/07. The year over year decrease reflected natural declines in base production due to the Company's strategic decision to reduce spending on natural gas drilling.
- Canadian Natural targeted 62 net natural gas wells in Q3/08. In Northeast British Columbia, 2 net wells were drilled, while in Northwest Alberta, 7 net wells were drilled. In the Northern Plains, 38 net wells were drilled, with 15 net wells drilled in the Southern Plains.
- Planned drilling activity for Q4/08 includes 31 natural gas wells compared to drilling activity for Q4/07 of 92 net natural gas wells.
- Inflationary pressure continues to affect capital and service costs for natural gas drilling. Cost control and maximizing shareholder value remain priorities within this business environment.

North America crude oil and NGLs

	Three Months Ended			Nine Months Ended	
	Sep 30 2008	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Crude oil and NGLs production (bbl/d)	**239,973**	245,616	252,095	**244,832**	243,388
Net wells targeting crude oil	**244**	94	153	**514**	438
Net successful wells drilled	**233**	92	150	**496**	416
Success rate	**95%**	**98%**	98%	**96%**	95%

- Q3/08 North America crude oil and NGLs production decreased 2% from Q2/08 and decreased 5% from Q3/07 levels. The decreases are a reflection of transitioning off the production cycle peaks at Primrose pads and continued polymer conversion at Pelican Lake.
- The Primrose East Expansion, a new facility located 15 kilometers from the existing Primrose South steam plant and 25 kilometers from the Wolf Lake central processing facility, is targeted to add production capacity of approximately 40,000 bbl/d of crude oil. Drilling and facility construction is complete, with first steam achieved in September and first production achieved in October versus the scheduled production target of Q1/09. Primrose East is the second phase of the 325,000 bbl/d thermal growth expansion plan identified to unlock the value from Canadian Natural's thermal crude oil resource base.
- In early 2007, Canadian Natural announced its proposed third phase of the thermal growth plan with a development plan for the production capacity of 45,000 bbl/d Kirby In-Situ Oil Sands Project located approximately 85 km

northeast of Lac La Biche in the Regional Municipality of Wood Buffalo. The Company has filed its formal regulatory application documents for this project as part of the Company's normal course of business.

- Development of new pads and secondary recovery conversion projects at Pelican Lake continued as expected throughout Q3/08. In Q3/08, the Company drilled 35 horizontal wells with plans to drill an additional 18 horizontal wells throughout the remainder of 2008. Pelican Lake production averaged approximately 37,000 bbl/d for Q3/08 compared to approximately 35,000 bbl/d for Q3/07 and approximately 37,000 bbl/d for Q2/08. The response from the polymer flood project continues to be positive and the Company is moving forward on converting regions currently under waterflood to polymer flood and expanding the polymer flood to new areas.
- Conventional heavy crude oil production volumes remained constant in Q3/08 compared to Q2/08, with volumes as expected.
- During Q3/08, drilling activity targeted 244 net crude oil wells including 152 wells targeting heavy crude oil, 35 wells targeting Pelican Lake crude oil, 16 wells targeting thermal crude oil and 41 wells targeting light crude oil.
- Planned drilling activity for Q4/08 includes 222 net crude oil wells, excluding stratigraphic test and service wells.
- Inflationary pressure continues to affect capital and service costs for crude oil drilling. Cost control and maximizing shareholder value remain priorities within this business environment.

International

	Three Months Ended			Nine Months Ended	
	Sep 30 2008	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Crude oil production (bbl/d)					
North Sea	**42,760**	45,830	52,013	**46,041**	57,020
Offshore West Africa	**24,237**	27,631	28,954	**26,842**	28,800
Natural gas production (mmcf/d)					
North Sea	**9**	10	10	**10**	13
Offshore West Africa	**14**	15	15	**14**	12
Net wells targeting crude oil	**0.6**	1.6	2.2	**4.4**	7.3
Net successful wells drilled	**0.6**	0.8	2.2	**3.6**	7.3
Success rate	**100%**	50%	100%	**82%**	100%

North Sea

- At the end of the quarter 0.9 net crude oil wells were in progress. Crude oil production was down 7% in Q3/08 to 42,760 bbl/d from 45,830 bbl/d in Q2/08 as a result of planned shutdowns for maintenance at Murchison, T-Block and Banff.
- Focus continues on infill drilling and workover opportunities with a workover completed at Murchison during the quarter. A further workover at Columba E and an oil well at Ninian were in progress at the end of the quarter.
- Focus on waterflood optimization at Ninian continues with water injection volumes in the quarter being the highest since Canadian Natural assumed operatorship in 2002.

Offshore West Africa

- Offshore West Africa's crude oil production decreased 12% in Q3/08 to 24,237 bbl/d from 27,631 bbl/d in Q2/08. A planned shutdown was undertaken at Baobab during the quarter for maintenance and tie in of the first new well from the drilling program. Espoir production declined due to the loss of two wells during the quarter; however a successful well intervention program restored production at one well during Q3/08 and the second well in early Q4/08.
- Progress on the Facility Upgrade Project at Espoir to increase capacity of the Floating, Production, Storage and Offtake Vessel ("FPSO") continues to progress ahead of schedule and is expected to be completed in Q3/09, an acceleration of 3 months from the original estimate.
- At Baobab, the Company continued with the deep water drilling program in order to restore shut-in production with one well brought on stream in Q3/08. Based on progress to date it is expected that 3 of the 5 Baobab wells will come on stream over the course of 2008 and 2009.
- The Olowi Project in Offshore Gabon has experienced a delay in construction of the FPSO and first oil is expected during Q1/09. During Q3/08 construction of the Conductor Supported Platform Deck was completed in November of 2008. Two appraisal wells have been drilled and development is continuing as planned.

Horizon Project

- Canadian Natural continues the completion of the construction, commissioning and staged start up of the Horizon Project. There have been some challenges encountered and overcome in the drive to complete the Project and commence production of SCO. These challenges have primarily related to commissioning and start up of the more complex components of the Project. The challenges have been resolved in the Delayed Coker, the Co-generation Plant and the Hydrogen Plant. Outstanding matters are currently being resolved in the Naphtha Hydrotreater and Gas Oil Hydrotreater in the Secondary Upgrading process.
- First SCO production is targeted for late in the fourth quarter of 2008 but the Company recognizes that there must not be any further delays in the completion or commissioning of these complex components of the Project. The construction and operations teams in all areas continue to work together to resolve issues and continue to test and prepare the site for operations.
- Canadian Natural is continuing with the staged start up of the Horizon Project. The seven stages to the start up of the Horizon Project, as outlined in the second quarter update release, and the associated targeted start up dates are as follow:

  - **Stage 1** - Mining. The Mining Operation is ready and continues to move overburden. The mining team has already delivered over 300,000 tonnes of mined oil sands to the Plant for test purposes.
  - **Stage 2** - Steam Supply**.** As previously targeted, the utility plants have been supplying low, medium and high pressure steam for commissioning and start up purposes since July of this year.
  - **Stage 3** - Bitumen Crude Oil Production. The Bitumen Crude Oil Production operations are fully commissioned except for Froth Treatment. The delays encountered in Froth Treatment have now been resolved. The necessary re-work is completed and commissioning is well underway. As previously targeted, first bitumen crude oil production of approximately 160,000 barrels for test purposes was achieved in September.
  - **Stage 4** - Electricity Generation. The Co-generation Plant has been producing steam since late July. Electricity generation has been commissioned and is ready for operations.
  - **Stage 5** - Sulphur Plant/Sour Gas Treating. The Sulphur Plant is complete and is being turned over to operations for commissioning.
  - **Stage 6** - Partially Upgraded Crude Oil Production. The Delayed Coker/Diluent Recovery Unit Plants were completed in late October, have been turned over to operations for commissioning and are currently circulating diesel and waiting for Secondary Upgrading to start up.

- **Stage 7** - 34˚API, Light Sweet Synthetic Crude Oil Production. The Naphtha Hydrotreating Plant (Plant 41) is completed and currently being commissioned. The Gas Oil Hydrotreating Plant (Plant 43) is completing electrical heat tracing and insulation concurrent with commissioning. With an estimated start up capacity of 70,000 bbl/d, first delivery of 34˚ API, light sweet SCO to the sales pipeline is currently targeted for late in the fourth quarter of 2008. The Distillate Hydrotreating Plant (Plant 42) is mechanically complete except for electrical heat tracing and insulation. First product output through Plant 42 is currently targeted for the latter part of Q1/09, enabling production start to ramp up to targeted facility capacity of 110,000 bbl/d of SCO. Targeted production ramp up would see 50-60% of facility capacity by the end of Q1/09 and reach full targeted facility capacity by later in 2009.

▪ The majority of the processing plants are either fully commissioned or well into commissioning. The remaining work is being carefully managed, ensuring a successful project by having all the necessary systems operational for cold weather.

▪ The safety and well-being of the Horizon Project contractors and operation staff remains a priority. On-site manpower is ramping down and the Company has reduced its construction workforce by over 50% during Q3/08 to approximately 2,500 tradesmen currently on site. The necessary operators required for start up and a strong management team are all in place.

▪ A high level overview of progress by major plant facility at the Horizon Project is as follows:

  - **Mining** – Completed, ready for oil sands mining operation, continues to move overburden
  - **Ore Preparation Plant** – Completed, ready for operation
  - **Hydrotransport** – Completed, ready for operation
  - **Piperack** – Completed, live and operational
  - **Extraction** – Completed, ready for operation
  - **Froth Treatment** – Completed, in commissioning and testing
  - **Delayed Coker/Diluent Recovery Unit** – Completed, circulating diesel and ready for operation
  - **Co-generation** – Completed, producing steam and power
  - **Sulphur Plant** – Completed, turned over to operations for commissioning and testing
  - **Tankage** – Completed, ready for operation
  - **Main Control Room** – Completed, live and operational
  - **Utilities & Services** – Completed, live and operational
  - **SCO Pipeline (third party owned and operated)** – Completed, ready for operation
  - **Hydrogen Plant** – Completed, turned over to operations for commissioning and testing
  - **Hydrotreaters** – Plant 41 has been completed and turned over to operations for commissioning and testing. Plant 43 is completing electrical heat tracing and insulation while starting commissioning and testing. Plant 42 is mechanically complete with electrical heat tracing and insulation to be completed before turning the plant over to operations for commissioning and testing.

▪ Delays and an extended commissioning schedule has led to an increase of $441 million to the Project forecast construction costs. This results in the revised total construction cost estimate for Phase 1 of the Horizon Project to be approximately $9.7 billion. The targeted on-stream cost estimate is $88,200 bbl/d capacity, including the benefits of the significant pre-build capital invested for future phases.

MARKETING

	Three Months Ended			Nine Months Ended	
	Sep 30 2008	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Crude oil and NGLs pricing					
WTI [1] benchmark price (US$/bbl)	**$ 118.13**	$ 124.00	$ 75.33	**$ 113.38**	$ 66.26
Western Canadian Select blend differential[2] from WTI (%)	**15%**	17%	30%	**18%**	29%
Corporate average pricing before risk management (C$/bbl)	**$ 102.30**	$ 103.73	$ 58.10	**$ 94.72**	$ 54.57
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 8.78**	$ 8.86	$ 5.32	**$ 8.16**	$ 6.46
Corporate average pricing before risk management (C$/mcf)	**$ 8.82**	$ 9.89	$ 5.87	**$ 8.83**	$ 7.03

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

(2) Beginning in Q1 2008, the Company has quantified the Heavy Differential using the Western Canadian Select ("WCS") blend as the heavy crude oil marker. Prior period amounts have been reclassified.

- In Q3/08, the WCS heavy crude oil differential as a percent of WTI was 15%, compared to 17% in Q2/08. Heavy crude oil differentials improved in Q3/08 due to a strong worldwide demand for diesel and low crack spreads, with overall high demand for crude oil products. Combined with declining heavy crude oil production in Mexico, and increased Venezuelan supply shipments to the Asian markets, US demand has been strong for Canadian heavy crude oil.

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

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

- The Company sees this as a strategic component to its heavy crude oil development which targets an increase to heavy crude oil production capacity from just over 200,000 bbl/d today, to over 500,000 bbl/d over the course of the next 15 years. Canadian heavy crude oil is very competitive against other international grades available in the US Gulf Coast. For Q3/08, the differential for the heavy crude oil marker, Mayan grade, was US$11.47/bbl or 10%.

- During Q3/08, the Company contributed approximately 147,000 bbl/d of its heavy crude oil streams to the WCS blend as market conditions resulted in this strategy offering the optimal pricing for bitumen crude oil.

- Natural gas pricing for Q3/08 was volatile compared to prior periods primarily as a result of fluctuations in demand and storage levels. North America natural gas inventory levels increased significantly during the third quarter due to increased shale gas production in the US and lower weather related demand.

FINANCIAL REVIEW

- The current worldwide credit events have resulted in disruptions in the availability of credit on commercially acceptable terms. In light of these credit challenges, the Company has undertaken a thorough review of its liquidity sources as well as its exposure to counterparties and has concluded that its capital resources are sufficient to meet ongoing short, medium and long-term commitments. Specifically, the Company continues to believe that its internally generated cash flow from operations supported by the implementation of its hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing credit facilities and its ability to raise new debt on commercially acceptable terms, will provide sufficient liquidity to sustain its operations in the short, medium and long-term and support its growth strategy. Further, the Company believes that its counterparties currently have the financial capacity to settle outstanding obligations in the normal course of business. A brief summary of the Company's strengths are:
  - A diverse asset base geographically and by product - produced in excess of 555,000 boe/d in Q3/08, 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 $1.8 billion for Q3/08, with available unused bank lines of $2.4 billion at September 30, 2008.
  - Reduced volatility of commodity prices - a proactive commodity hedging program to reduce the downside risk of volatility in commodity prices supporting cash flow for its capital expenditure program.
  - A strengthening balance sheet with debt to book capitalization of 41% and debt to EBITDA of 1.7 times, both within targeted ranges.
- In 2007 and 2008, the Province of Alberta issued certain details of its proposed changes to the Alberta crude oil and natural gas royalty regime, effective January 1, 2009. The Company is currently awaiting finalization and government approval of the royalty regulations, however it expects that its 2009 and future Alberta royalty payments will increase as a result of the proposed royalty changes and that its level of activity in Alberta in aggregate will be reduced from what it otherwise would have been in the absence of such royalty changes.
- Declared a quarterly cash dividend on common shares of C$0.10 per common share, payable January 1, 2009.

OUTLOOK

The Company forecasts 2008 production levels before royalties to average between 1,492 and 1,506 mmcf/d of natural gas and between 313,000 and 318,000 bbl/d of crude oil and NGLs. Q4/08 production guidance before royalties is forecast to average between 1,430 and 1,455 mmcf/d of natural gas and between 300,000 and 316,000 bbl/d of crude oil and NGLs. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at http://www.cnrl.com/investor_info/corporate_guidance/.

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MANAGEMENT'S DISCUSSION AND ANALYSIS

Forward-Looking Statements

Certain statements in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, production volumes, royalties, operating costs, capital expenditures and other guidance provided throughout this Management's Discussion and Analysis ("MD&A"), constitutes forward-looking statements. In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

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

The forward-looking statements are based on current expectations, estimates and projections about Canadian Natural Resources Limited (the "Company") and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks, uncertainties and other factors that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete its capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected difficulties in mining, extracting or upgrading the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, bitumen, natural gas and liquids not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses. The Company's operations have been, and at times in the future may be, affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of important factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements should circumstances or Management's estimates or opinions change.

Management's Discussion and Analysis

Management's Discussion and Analysis of the financial condition and results of operations of the Company should be read in conjunction with the unaudited interim consolidated financial statements for the nine and three months ended September 30, 2008 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2007.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The financial statements have been prepared in accordance with 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 non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with GAAP, in the "Financial Highlights" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

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

Production volumes are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices exclude the effect of risk management activities and transportation and blending costs, except where noted otherwise. Production on an "after royalty" or "net" basis is also presented for information purposes only.

The following discussion refers primarily to the Company's financial results for the nine and three months ended September 30, 2008 in relation to the comparable periods in 2007 and the second quarter of 2008. The accompanying tables form an integral part of this MD&A. This MD&A is dated November 4, 2008. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2007, is available on SEDAR at www.sedar.com.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Nine Months Ended	
	Sep 30 2008	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Revenue, before royalties	**$ 4,583**	$ 5,112	$ 3,073	**$ 13,662**	$ 9,343
Net earnings (loss)	**$ 2,835**	$ (347)	$ 700	**$ 3,215**	$ 1,810
Per common share – basic and diluted	**$ 5.25**	$ (0.65)	$ 1.30	**$ 5.95**	$ 3.36
Adjusted net earnings from operations (1)	**$ 963**	$ 960	$ 644	**$ 2,795**	$ 1,860
Per common share – basic and diluted	**$ 1.78**	$ 1.78	$ 1.19	**$ 5.17**	$ 3.44
Cash flow from operations (2)	**$ 1,815**	$ 1,859	$ 1,577	**$ 5,399**	$ 4,712
Per common share – basic and diluted	**$ 3.36**	$ 3.44	$ 2.92	**$ 9.99**	$ 8.74
Capital expenditures, net of dispositions	**$ 1,744**	$ 2,127	$ 1,442	**$ 5,624**	$ 4,911

(1) Adjusted net earnings from operations is a non-GAAP measure that represents net earnings adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings from operations. The reconciliation "Adjusted Net Earnings from Operations" presented below lists the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.

(2) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items before working capital adjustments. The Company evaluates its performance based on cash flow from operations. The Company considers cash flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Cash Flow from Operations" presented below lists certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings from Operations

($ millions)	*Three Months Ended*			*Nine Months Ended*	
	Sep 30 2008	*Jun 30 2008*	*Sep 30 2007*	***Sep 30 2008***	*Sep 30 2007*
Net earnings (loss) as reported	***$ 2,835***	*$ (347)*	*$ 700*	***$ 3,215***	*$ 1,810*
Stock-based compensation (recovery) expense, net of tax (a)	***(221)***	*328*	*54*	***107***	*145*
Unrealized risk management (gain) loss, net of tax (b)	***(1,750)***	*997*	*57*	***(677)***	*384*
Unrealized foreign exchange loss (gain), net of tax (c)	***99***	*(18)*	*(167)*	***191***	*(408)*
Effect of statutory tax rate and other legislative changes on future income tax liabilities (d)	***-***	*-*	*-*	***(41)***	*(71)*
Adjusted net earnings from operations	***$ 963***	*$ 960*	*$ 644*	***$ 2,795***	*$ 1,860*

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

(b) Derivative financial instruments are recorded at fair value on the balance sheet, with changes in fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil and natural gas.

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

(d) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's consolidated balance sheet in determining future income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted. Income tax rate changes in the first quarter of 2008 resulted in a reduction of future income tax liabilities of approximately $19 million in North America and $22 million in Côte d'Ivoire, Offshore West Africa. Income tax rate changes in the second quarter of 2007 resulted in a reduction of future income tax liabilities of approximately $71 million in North America.

Cash Flow from Operations

($ millions)	Three Months Ended **Sep 30 2008**	Jun 30 2008	Sep 30 2007	Nine Months Ended **Sep 30 2008**	Sep 30 2007
Net earnings (loss)	***$ 2,835***	*$ (347)*	*$ 700*	***$ 3,215***	*$ 1,810*
Non-cash items:					
Depletion, depreciation and amortization	***659***	*670*	*715*	***2,017***	*2,144*
Asset retirement obligation accretion	***18***	*17*	*18*	***52***	*53*
Stock-based compensation (recovery) expense	***(308)***	*459*	*78*	***151***	*209*
Unrealized risk management (gain) loss	***(2,506)***	*1,415*	*76*	***(983)***	*555*
Unrealized foreign exchange loss (gain)	***113***	*(20)*	*(195)*	***219***	*(477)*
Deferred petroleum revenue tax (recovery) expense	***(7)***	*(34)*	*10*	***(62)***	*27*
Future income tax expense (recovery)	***1,011***	*(301)*	*175*	***790***	*391*
Cash flow from operations	***$ 1,815***	*$ 1,859*	*$ 1,577*	***$ 5,399***	*$ 4,712*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the nine months ended September 30, 2008 were $3,215 million compared to $1,810 million for the nine months ended September 30, 2007. Net earnings for the nine months ended September 30, 2008 included net unrealized after-tax income of $420 million related to the effects of risk management activities, changes in foreign exchange rates and stock-based compensation, and the impact of statutory tax rate changes on future income tax liabilities, compared to net unrealized after-tax expenses of $50 million for the nine months ended September 30, 2007. Excluding these items, adjusted net earnings from operations for the nine months ended September 30, 2008 increased to a record $2,795 million compared to $1,860 million for the nine months ended September 30, 2007. The increase in adjusted net earnings from the comparable period in 2007 was primarily due to the impact of higher realized pricing, lower depletion, depreciation and amortization expense, and lower interest and administration expense. These factors were partially offset by higher realized risk management losses, higher royalty and production expense, lower sales volumes, and the impact of the stronger Canadian dollar relative to the US dollar.

Net earnings for the third quarter of 2008 was $2,835 million compared to net earnings of $700 million for the third quarter of 2007 and a net loss of $347 million for the prior quarter. The net earnings for the third quarter of 2008 included net unrealized after-tax income of $1,872 million related to the effects of risk management activities, fluctuations in foreign exchange rates, and fluctuations in stock-based compensation, compared to net unrealized after-tax income of $56 million for the third quarter of 2007 and net unrealized after-tax expenses of $1,307 million for the prior quarter. Excluding these items, adjusted net earnings from operations for the third quarter of 2008 increased to $963 million compared to $644 million for the third quarter of 2007 and $960 million for the prior quarter. The increase in adjusted net earnings from the third quarter of 2007 was primarily due to the impact of higher realized pricing, lower depletion, depreciation and amortization expense, and lower interest and administration expense. These factors were partially offset by higher realized risk management losses, higher royalty and production expense, and lower sales volumes. The increase in adjusted net earnings from the prior quarter was primarily due to the impact of lower depletion, depreciation and amortization expense, lower realized risk management losses, lower royalty expense, lower interest expense, and the impact of the weaker Canadian dollar, partially offset by the impact of lower sales volumes and higher production expense.

The impacts of unrealized risk management activities, stock-based compensation and changes in foreign exchange rates are expected to continue to contribute to significant quarterly volatility in consolidated net earnings and are discussed in detail in the relevant sections of this MD&A.

Cash flow from operations for the nine months ended September 30, 2008 increased to a record $5,399 million compared to $4,712 million for the nine months ended September 30, 2007. The increase from the comparable period in 2007 was primarily due to the impact of higher realized pricing, and lower interest and administration expense, partially offset by higher realized risk management losses, higher royalty and production expense, higher current income tax expense, lower sales volumes, and the impact of the stronger Canadian dollar relative to the US dollar.

Cash flow from operations for the third quarter of 2008 increased to $1,815 million compared to $1,577 million for the third quarter of 2007 and decreased slightly from $1,859 million for the prior quarter. The increase from the third quarter of 2007 was primarily due to the impact of higher realized pricing, and lower interest and administration expense, partially offset by higher realized risk management losses, higher royalty and production expense, higher current income tax expense, lower sales volumes and the impact of the stronger Canadian dollar relative to the US dollar. The decrease from the prior quarter was primarily due to the impact of lower sales volumes and higher production expense, partially offset by lower realized risk management losses, lower royalty expense, and the impact of the weaker Canadian dollar.

Total production before royalties for the nine months ended September 30, 2008 decreased 7% to average 570,704 boe/d from 611,665 boe/d for the nine months ended September 30, 2007. Production for the third quarter of 2008 decreased 9% to 555,356 boe/d from 607,484 boe/d for the third quarter of 2007 and 3% from 573,437 boe/d for the prior quarter. Total production for the third quarter of 2008 was within the Company's previously issued guidance.

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

SUMMARY OF QUARTERLY RESULTS

The following is a summary of the Company's quarterly results for the eight most recently completed quarters:

($ millions, except per common share amounts)		**Sep 30 2008**		Jun 30 2008		Mar 31 2008		Dec 31 2007
Revenue, before royalties	**$**	**4,583**	$	5,112	$	3,967	$	3,200
Net earnings (loss)	**$**	**2,835**	$	(347)	$	727	$	798
Net earnings (loss) per common share								
– Basic and diluted	**$**	**5.25**	$	(0.65)	$	1.35	$	1.48

($ 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

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

- Crude oil pricing

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

- Crude oil and NGLs sales volumes

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

- Natural gas sales volumes

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

- Foreign exchange rates

  A general strengthening of the Canadian dollar relative to the US dollar has decreased the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominately on US dollar denominated benchmarks. Similarly, unrealized foreign exchange gains and losses were recorded with respect to US dollar denominated debt balances and the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars, partially offset by the impact of cross currency swaps.

- Risk management

  Net earnings have fluctuated due to the recognition of realized and unrealized gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.

- Changes in income tax expense

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

- Stock-based compensation

  Net earnings have fluctuated due to the mark-to-market movements of the Company's stock-based compensation liability. Stock-based compensation expense (recovery) reflected fluctuations in the Company's share price over the eight most recently completed quarters.

- Production expense

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

- Depletion, depreciation and amortization

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

OPERATING HIGHLIGHTS

	Three Months Ended			Nine Months Ended	
	Sep 30 2008	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Crude oil and NGLs ($/bbl) [1]					
Sales price [2]	**$ 102.30**	$ 103.73	$ 58.10	**$ 94.72**	$ 54.57
Royalties	**14.17**	14.82	6.65	**12.49**	5.69
Production expense	**17.61**	16.39	13.13	**16.24**	13.97
Netback	**$ 70.52**	$ 72.52	$ 38.32	**$ 65.99**	$ 34.91
Natural gas ($/mcf) [1]					
Sales price [2]	**$ 8.82**	$ 9.89	$ 5.87	**$ 8.83**	$ 7.03
Royalties	**1.55**	1.86	0.89	**1.59**	1.16
Production expense	**1.05**	0.94	0.88	**1.01**	0.91
Netback	**$ 6.22**	$ 7.09	$ 4.10	**$ 6.23**	$ 4.96
Barrels of oil equivalent ($/boe) [1]					
Sales price [2]	**$ 80.60**	$ 84.88	$ 47.96	**$ 76.73**	$ 48.99
Royalties	**12.06**	13.26	6.07	**11.22**	6.27
Production expense	**12.52**	11.60	9.62	**11.70**	10.05
Netback	**$ 56.02**	$ 60.02	$ 32.27	**$ 53.81**	$ 32.67

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

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

BUSINESS ENVIRONMENT

	Three Months Ended			Nine Months Ended	
	Sep 30 2008	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
WTI benchmark price (US$/bbl)	**$ 118.13**	$ 124.00	$ 75.33	**$ 113.38**	$ 66.26
Dated Brent benchmark price (US$/bbl)	**$ 114.96**	$ 121.39	$ 74.85	**$ 111.11**	$ 67.18
WCS blend differential from WTI (US$/bbl) (1)	**$ 17.98**	$ 21.62	$ 22.39	**$ 20.33**	$ 19.04
WCS blend differential from WTI (%) (1)	**15%**	17%	30%	**18%**	29%
Condensate benchmark price (US$/bbl)	**$ 118.57**	$ 124.64	$ 75.93	**$ 113.89**	$ 66.82
NYMEX benchmark price (US$/mmbtu)	**$ 10.11**	$ 10.80	$ 6.13	**$ 9.66**	$ 6.88
AECO benchmark price (C$/GJ)	**$ 8.78**	$ 8.86	$ 5.32	**$ 8.16**	$ 6.46
US / Canadian dollar average exchange rate	**$ 0.9605**	$ 0.9900	$ 0.9565	**$ 0.9819**	$ 0.9045

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

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$113.38 per bbl for the nine months ended September 30, 2008, an increase of 71% from US$66.26 per bbl for the nine months ended September 30, 2007. WTI averaged US$118.13 per bbl for the third quarter of 2008, an increase of 57% from US$75.33 per bbl for the third quarter of 2007, and a decrease of 5% from US$124.00 per bbl for the prior quarter. WTI pricing during the third quarter of 2008 continued to reflect strong demand for crude oil, tight supply and ongoing geopolitical uncertainty, particularly in July 2008 when WTI crude oil futures hit an all time high of approximately US$147.00 per bbl. WTI pricing significantly weakened toward the end of the third quarter and traded below US$70.00 in October 2008. This decrease in WTI pricing was partially offset by a significant weakening in the Canadian dollar compared to the US dollar, with the Canadian dollar falling below US$0.80 in October 2008.

Crude oil sales contracts for the Company's North Sea and Offshore West Africa segments are typically based on Dated Brent ("Brent") pricing, which generally continued to benefit from strong European and Asian demand. Brent averaged US$111.11 per bbl for the nine months ended September 30, 2008; an increase of 65% compared to US$67.18 per bbl for the nine months ended September 30, 2007. In the third quarter of 2008, Brent averaged US$114.96 per bbl, an increase of 54% compared to US$74.85 per bbl for the third quarter of 2007, and a decrease of 5% from US$121.39 per bbl for the prior quarter. Similar to WTI pricing, Brent pricing significantly weakened toward the end of the third quarter.

The Company's realized crude oil prices increased from the nine months ended September 30, 2007 primarily as a result of increased WTI and Brent pricing and a narrower Heavy Differential, offset by the impact of a strong Canadian dollar. The Heavy Differential averaged 18% for the nine months ended September 30, 2008 compared to 29% for the nine months ended September 30, 2007. For the third quarter of 2008, the Heavy Differential averaged 15% compared to 30% for the third quarter of 2007, and 17% for the prior quarter. The narrowing of the Heavy Differential from the comparable periods was primarily due to increased demand for heavy crude oil due to reduced refinery cracking margins and increased demand for diesel. Realized prices continued to be adversely impacted by the strong Canadian dollar.

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

NYMEX natural gas prices averaged US$9.66 per mmbtu for the nine months ended September 30, 2008, an increase of 40% from US$6.88 per mmbtu for the nine months ended September 30, 2007. For the third quarter of 2008, NYMEX natural gas prices averaged US$10.11 per mmbtu, an increase of 65% from US$6.13 per mmbtu for the third quarter of 2007, and a decrease of 6% from US$10.80 per mmbtu for the prior quarter. AECO natural gas prices for the nine months ended September 30, 2008 increased 26% to average $8.16 per GJ from $6.46 per GJ for the nine months ended September 30, 2007. For the third quarter of 2008, AECO natural gas prices averaged $8.78 per GJ, an increase of 65% from $5.32 per GJ in the third quarter of 2007 and a decrease of 1% from $8.86 per GJ for the prior quarter. Fluctuations in natural gas prices from the comparable periods were primarily related to demand and storage levels. North America natural gas inventory levels increased significantly during the third quarter of 2008 due to increased shale gas production in the US and lower weather related demand.

Operating, Royalty and Capital Costs

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

The crude oil and natural gas industry is also experiencing cost pressures related to environmental regulations, both in North America and internationally. In Canada, the Federal Government has indicated its intent to develop regulations that would be in effect in 2010 to address industrial greenhouse gas ("GHG") emissions. The Federal Government has also outlined national and sectoral reduction targets for several categories of air pollutants. In Alberta, GHG regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually. Two of the Company's facilities, the Primrose/Wolf Lake in-situ heavy crude oil facilities and the Hays sour natural gas plant, are captured under the regulations. In the UK, GHG regulations have been in effect since 2005. During Phase 1 (2005 –2007) of the UK National Allocation Plan the Company operated below its CO_2 allocation. For Phase 2 (2008 – 2012) the Company's CO_2 allocation has been decreased below the Company's estimated current operations emissions. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO_2 emissions at its major facilities and on trading mechanisms to ensure compliance with requirements now in effect.

Commencing July 1, 2008, the British Columbia carbon tax is being assessed at $10/tonne of CO_2e on fuel consumed in the province, increasing to $30/tonne by July 1, 2012.

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.

In 2007 and 2008, the Province of Alberta issued certain details of its proposed changes to the Alberta crude oil and natural gas royalty regime, effective January 1, 2009. These proposed changes include:

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

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

PRODUCT PRICES

	Three Months Ended			Nine Months Ended	
	Sep 30 2008	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 99.05**	$ 97.94	$ 52.47	**$ 89.83**	$ 48.68
North Sea	**$ 109.82**	$ 129.57	$ 77.55	**$ 111.82**	$ 72.86
Offshore West Africa	**$ 125.71**	$ 114.56	$ 70.52	**$ 110.93**	$ 67.37
Company average	**$ 102.30**	$ 103.73	$ 58.10	**$ 94.72**	$ 54.57
Natural gas ($/mcf) (1) (2)					
North America	**$ 8.83**	$ 9.94	$ 5.88	**$ 8.86**	$ 7.05
North Sea	**$ 3.65**	$ 4.27	$ 5.26	**$ 3.73**	$ 4.47
Offshore West Africa	**$ 11.18**	$ 8.97	$ 5.31	**$ 9.33**	$ 5.76
Company average	**$ 8.82**	$ 9.89	$ 5.87	**$ 8.83**	$ 7.03
Company average ($/boe) (1) (2)	**$ 80.60**	$ 84.88	$ 47.96	**$ 76.73**	$ 48.99
Percentage of gross revenue (2) (excluding midstream revenue)					
Crude oil and NGLs	**70%**	68%	67%	**69%**	60%
Natural gas	**30%**	32%	33%	**31%**	40%

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

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

The Company's realized crude oil prices increased 74% to average $94.72 per bbl for the nine months ended September 30, 2008 from $54.57 per bbl for the nine months ended September 30, 2007. Realized crude oil prices for the third quarter of 2008 increased 76% to average $102.30 per bbl from $58.10 per bbl for the third quarter of 2007, and decreased 1% from $103.73 per bbl for the prior quarter. The Company's realized crude oil prices increased from the comparable periods in 2007 primarily as a result of increased WTI and Brent benchmark prices and a narrower Heavy Differential, partially offset by a strong Canadian dollar relative to the US dollar. The decrease from the prior quarter was primarily due to declining WTI and Brent benchmark prices, partially offset by a narrower Heavy Differential and the impact of the weakening Canadian dollar relative to the US dollar.

The Company's realized natural gas price increased 26% to average $8.83 per mcf for the nine months ended September 30, 2008 from $7.03 per mcf for the nine months ended September 30, 2007. Realized natural gas prices for the third quarter of 2008 increased 50% to average $8.82 per mcf from $5.87 per mcf for the third quarter of 2007, and decreased 11% from $9.89 per mcf for the prior quarter. The increase in realized natural gas prices from the comparable periods in 2007 primarily reflected increased benchmark prices due to increased industrial consumption, colder weather experienced late in the first quarter of 2008, and lower liquefied natural gas imports into the US in the first half of 2008. The decrease in realized natural gas prices from the prior quarter was primarily due to higher storage levels due to increased shale gas production in the US, and lower demand resulting from milder weather experienced during the third quarter of 2008.

North America

North America realized crude oil prices increased 85% to average $89.83 per bbl for the nine months ended September 30, 2008 from $48.68 per bbl for the nine months ended September 30, 2007. Realized crude oil prices increased 89% to average $99.05 per bbl for the third quarter of 2008 from $52.47 per bbl for the third quarter of 2007, and increased 1% from $97.94 bbl for the prior quarter. The increase from the comparable periods in 2007 was due to the increase in WTI benchmark pricing and a narrower Heavy Differential. The increase from the prior quarter was due to a narrower Heavy Differential and the impact of the weakening Canadian dollar relative to the US dollar, partially offset by declining WTI benchmark pricing.

In North America, the Company continues to focus on its crude oil marketing strategy, including the development of a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil conversion capacity. During the third quarter, the Company contributed approximately 147,000 bbl/d of heavy crude oil blends to the WCS stream. The Company has also entered into a 20 year transportation agreement to commit to ship 120,000 bbl/d of heavy sour crude oil on the proposed 500,000 bbl/d Keystone Pipeline US Gulf Coast expansion from Hardisty, Alberta to the US Gulf Coast. Contemporaneously, the Company also entered into a 20 year crude oil purchase and sales agreement to sell 100,000 bbl/d of heavy sour crude oil to a major US refiner. Deliveries under the agreements are expected to commence in 2012 upon completion of the pipeline expansion and are subject to Keystone’s receipt of regulatory approval of the pipeline expansion as well as minimum levels of shipper commitments.

North America realized natural gas prices increased 26% to average $8.86 per mcf for the nine months ended September 30, 2008 from $7.05 per mcf for the nine months ended September 30, 2007. Realized North America natural gas prices increased 50% to average $8.83 per mcf for the third quarter of 2008 from $5.88 per mcf for the third quarter of 2007, and decreased 11% from $9.94 per mcf for the prior quarter. The fluctuations in natural gas prices from the comparable periods in 2007 and the prior quarter were primarily related to the fluctuations in benchmark prices.

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

	Sep 30 2008	Jun 30 2008	Sep 30 2007
Wellhead Price (1) (2)			
Light/medium crude oil and NGLs (C$/bbl)	**$ 108.13**	$ 113.92	$ 67.55
Pelican Lake crude oil (C$/bbl)	**$ 95.58**	$ 98.28	$ 48.91
Primary heavy crude oil (C$/bbl)	**$ 97.30**	$ 95.39	$ 47.47
Thermal heavy crude oil (C$/bbl)	**$ 97.06**	$ 88.72	$ 48.99
Natural gas (C$/mcf)	**$ 8.83**	$ 9.94	$ 5.88

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

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

North Sea

North Sea realized crude oil prices increased 53% to average $111.82 per bbl for the nine months ended September 30, 2008 from $72.86 per bbl for the nine months ended September 30, 2007. Realized North Sea crude oil prices increased 42% to average $109.82 per bbl for the third quarter of 2008 from $77.55 per bbl for the third quarter of 2007, and decreased by 15% from $129.57 per bbl for the prior quarter. Realized crude oil prices per bbl in any particular quarter are dependant on the terms of the various sales contracts, the frequency and timing of liftings of certain fields, and prevailing crude prices at the time of lifting. 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 strong Canadian dollar.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 65% to average $110.93 per bbl for the nine months ended September 30, 2008 from $67.37 per bbl for the nine months ended September 30, 2007. Realized Offshore West Africa crude oil prices increased 78% to average $125.71 per bbl for the third quarter of 2008 from $70.52 per bbl for the third quarter of 2007, and increased 10% from $114.56 per bbl for the prior quarter. Realized crude oil prices per bbl in any particular quarter are dependant on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude prices at the time of lifting. 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 strong Canadian 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 volumes by segment, which have not been recognized in revenue, were as follows:

(bbl)	**Sep 30 2008**	Jun 30 2008	Dec 31 2007
North America, related to pipeline fill	**1,097,526**	1,097,526	1,097,526
North Sea, related to timing of liftings	**628,642**	802,576	1,032,723
Offshore West Africa, related to timing of liftings	**862,183**	377,741	8,578
	2,588,351	2,277,843	2,138,827

In the third quarter of 2008, an additional 311,000 barrels of crude oil produced in the Company's international operations was not lifted and was therefore included in inventory at September 30, 2008. Notwithstanding an overall increase in inventory, consolidated cash flow from operations increased by approximately $10 million, primarily due to fluctuations in prevailing crude oil prices.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2008	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Crude oil and NGLs (bbl/d)					
North America	**239,973**	245,616	252,095	**244,832**	243,388
North Sea	**42,760**	45,830	52,013	**46,041**	57,020
Offshore West Africa	**24,237**	27,631	28,954	**26,842**	28,800
	306,970	319,077	333,062	**317,715**	329,208
Natural gas (mmcf/d)					
North America	**1,467**	1,501	1,622	**1,494**	1,670
North Sea	**9**	10	10	**10**	13
Offshore West Africa	**14**	15	15	**14**	12
	1,490	1,526	1,647	**1,518**	1,695
Total barrels of oil equivalent (boe/d)	**555,356**	573,437	607,484	**570,704**	611,665
Product mix					
Light/medium crude oil and NGLs	**21%**	22%	22%	**22%**	23%
Pelican Lake crude oil	**7%**	6%	6%	**7%**	6%
Primary heavy crude oil	**16%**	16%	16%	**16%**	15%
Thermal heavy crude oil	**11%**	12%	11%	**11%**	10%
Natural gas	**45%**	44%	45%	**44%**	46%

DAILY PRODUCTION, net of royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2008	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Crude oil and NGLs (bbl/d)					
North America	**202,419**	202,264	213,680	**207,072**	208,370
North Sea	**42,665**	45,734	51,917	**45,945**	56,916
Offshore West Africa	**19,050**	24,136	26,158	**22,216**	26,311
	264,134	272,134	291,755	**275,233**	291,597
Natural gas (mmcf/d)					
North America	**1,217**	1,227	1,373	**1,234**	1,395
North Sea	**9**	10	10	**10**	13
Offshore West Africa	**11**	13	14	**12**	11
	1,237	1,250	1,397	**1,256**	1,419
Total barrels of oil equivalent (boe/d)	**470,268**	480,418	524,417	**484,593**	527,982

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

The Company’s business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely natural gas, light/medium crude oil and NGLs, Pelican Lake crude oil, primary heavy crude oil and thermal heavy crude oil.

Total production averaged 570,704 boe/d for the nine months ended September 30, 2008, a 7% decrease from 611,665 boe/d for the nine months ended September 30, 2007. Production for the third quarter of 2008 decreased 9% to average 555,356 boe/d, from 607,484 boe/d for the third quarter of 2007, and a 3% decrease from 573,437 boe/d for the prior quarter.

Total crude oil and NGLs production for the nine months ended September 30, 2008 decreased 3% to 317,715 bbl/d from 329,208 bbl/d for the nine months ended September 30, 2007. Third quarter total crude oil and NGLs production decreased 8% to 306,970 bbl/d from 333,062 bbl/d for the third quarter of 2007, and decreased 4% from 319,077 bbl/d for the prior quarter. The decrease from the comparable periods was primarily due to lower production in the North Sea and Offshore West Africa due to the timing of field turnarounds and the cyclic nature of the Company’s thermal production. Crude oil and NGLs production in the third quarter of 2008 was near the midpoint of the Company’s previously issued guidance of 299,000 to 316,000 bbl/d.

Natural gas production continued to represent the Company’s largest product offering, accounting for 45% of the Company’s total production in the third quarter of 2008. Natural gas production for the nine months ended September 30, 2008 averaged 1,518 mmcf/d compared to 1,695 mmcf/d for the nine months ended September 30, 2007. Third quarter natural gas production averaged 1,490 mmcf/d compared to 1,647 mmcf/d for the third quarter of 2007 and 1,526 mmcf/d for the prior quarter. The decrease in natural gas production from the comparable periods primarily reflected production declines due to the Company’s strategic reduction in natural gas drilling activity. Third quarter natural gas production was at the high end of the Company’s previously issued guidance of 1,466 to 1,490 mmcf/d.

For 2008, annual production guidance is targeted to average between 313,000 and 318,000 bbl/d of crude oil and NGLs and between 1,492 and 1,506 mmcf/d of natural gas. Fourth quarter 2008 production guidance is targeted to average between 300,000 and 316,000 bbl/d of crude oil and NGLs and between 1,430 and 1,455 mmcf/d of natural gas.

North America

North America crude oil and NGLs production for the nine months ended September 30, 2008 increased 1% to average 244,832 bbl/d from 243,388 bbl/d for the nine months ended September 30, 2007. Third quarter North America crude oil and NGLs production decreased 5% to average 239,973 bbl/d from 252,095 bbl/d for the third quarter of 2007, and decreased 2% from 245,616 bbl/d for the prior quarter. The fluctuations in crude oil and NGLs production from the prior periods was primarily due to the cyclic nature of the Company's thermal production.

For the nine months ended September 30, 2008, natural gas production decreased 11% to 1,494 mmcf/d from 1,670 mmcf/d for the nine months ended September 30, 2007. For the third quarter of 2008, natural gas production decreased 10% to 1,467 mmcf/d from 1,622 mmcf/d for the third quarter of 2007, and decreased 2% from 1,501 mmcf/d for the prior quarter. The decrease in natural gas production from the prior periods reflected production declines due to the Company's strategic decision to reduce natural gas drilling activity to focus on higher return crude oil projects.

North Sea

North Sea crude oil production for the nine months ended September 30, 2008 decreased 19% to 46,041 bbl/d from 57,020 bbl/d for the nine months ended September 30, 2007. Third quarter North Sea crude oil production decreased 18% to 42,760 bbl/d from 52,013 bbl/d for the third quarter of 2007 and by 7% from 45,830 bbl/d for the prior quarter. Third quarter production was at the low end of guidance with the decrease from the prior quarter due to the extended duration of the Murchison shutdown. Three planned maintenance shutdowns were successfully completed during the third quarter of 2008 at the Murchison, T-Block, and Banff Fields. Two platforms at the Ninian Field will be shutdown for maintenance in the fourth quarter.

Offshore West Africa

Offshore West Africa crude oil production decreased 7% to 26,842 bbl/d for the nine months ended September 30, 2008 from 28,800 bbl/d for the nine months ended September 30, 2007. Third quarter Offshore West Africa crude oil production decreased 16% to 24,237 bbl/d from 28,954 bbl/d for the third quarter of 2007, and by 12% from 27,631 bbl/d for the prior quarter. During the third quarter, a shutdown was taken at the Baobab Field for maintenance and to tie in the first new well delivered from the redrilling program. This well was onstream at quarter end and additional production is anticipated to be delivered in the fourth quarter. A well intervention program at Espoir had restored one shut-in production well during the quarter, with a second in progress at quarter end.

ROYALTIES

	Three Months Ended			Nine Months Ended	
	Sep 30 2008	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 15.76**	$ 17.46	$ 8.00	**$ 14.26**	$ 7.02
North Sea	**$ 0.24**	$ 0.27	$ 0.14	**$ 0.23**	$ 0.13
Offshore West Africa	**$ 26.90**	$ 14.49	$ 6.81	**$ 18.89**	$ 5.90
Company average	**$ 14.17**	$ 14.82	$ 6.65	**$ 12.49**	$ 5.69
Natural gas ($/mcf) (1)					
North America	**$ 1.55**	$ 1.88	$ 0.90	**$ 1.60**	$ 1.17
Offshore West Africa	**$ 2.24**	$ 1.13	$ 0.51	**$ 1.59**	$ 0.50
Company average	**$ 1.55**	$ 1.86	$ 0.89	**$ 1.59**	$ 1.16
Company average ($/boe) (1)	**$ 12.06**	$ 13.26	$ 6.07	**$ 11.22**	$ 6.27
Percentage of revenue (2)					
Crude oil and NGLs	**14%**	14%	11%	**13%**	10%
Natural gas	**18%**	19%	15%	**18%**	16%
Boe	**15%**	16%	13%	**15%**	13%

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

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

North America

North America crude oil and NGLs royalties per bbl for the nine months ended September 30, 2008 continue to reflect strong realized crude oil prices. Crude oil and NGLs royalties averaged approximately 16% of revenues for the third quarter of 2008, compared to 15% for the third quarter in 2007 and 18% in the prior quarter. Crude oil and NGLs royalties per bbl are anticipated to average 16% to 18% of gross revenue for 2008.

Natural gas royalties per mcf generally fluctuate with natural gas prices. Natural gas royalties averaged approximately 18% of revenues for the third quarter of 2008 compared to 15% for the third quarter of 2007 and 19% for the prior quarter. Natural gas royalties are anticipated to average 17% to 20% of gross revenue for 2008.

North Sea

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

Offshore West Africa

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

Royalty rates as a percentage of revenue averaged approximately 21% for the third quarter of 2008 compared to 10% for the third quarter of 2007 and 13% for the prior quarter. Royalty expense in the third quarter reflected a higher proportion of Espoir sales in the period, which have higher royalty rates. This increase was compounded by the impact of the reduction in the Côte d'Ivoire corporate income tax rate enacted in the first quarter of 2008, which increased the allocation of the Government's share of profit oil to royalties. Offshore West Africa royalty rates are anticipated to average 14% to 17% of gross revenue for 2008.

PRODUCTION EXPENSE

	Three Months Ended			Nine Months Ended	
	Sep 30 2008	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 16.23**	$ 15.44	$ 11.69	**$ 15.17**	$ 12.87
North Sea	**$ 29.21**	$ 25.61	$ 23.61	**$ 25.52**	$ 21.23
Offshore West Africa	**$ 7.74**	$ 9.79	$ 7.00	**$ 8.60**	$ 7.90
Company average	**$ 17.61**	$ 16.39	$ 13.13	**$ 16.24**	$ 13.97
Natural gas ($/mcf) [1]					
North America	**$ 1.03**	$ 0.93	$ 0.87	**$ 0.99**	$ 0.90
North Sea	**$ 3.09**	$ 2.68	$ 2.29	**$ 2.68**	$ 2.39
Offshore West Africa	**$ 1.58**	$ 1.27	$ 1.39	**$ 1.36**	$ 1.32
Company average	**$ 1.05**	$ 0.94	$ 0.88	**$ 1.01**	$ 0.91
Company average ($/boe) [1]	**$ 12.52**	$ 11.60	$ 9.62	**$ 11.70**	$ 10.05

(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, 2008 increased 18% to $15.17 per bbl from $12.87 per bbl for the nine months ended September 30, 2007. Third quarter North America crude oil and NGLs production expense increased 39% to $16.23 per bbl from $11.69 per bbl for the third quarter of 2007 and increased 5% from $15.44 per bbl for the prior quarter. The increase in production expense per bbl from the comparable periods was primarily a result of the higher cost of natural gas for fuel for the Company's thermal operations and increased property tax and power costs. The increase in the third quarter of 2008 was also a result of the timing of steam cycles at thermal properties and the impact of lower production volumes on the fixed cost portion of production costs.

North America natural gas production expense for the nine months ended September 30, 2008 increased 10% to $0.99 per mcf from $0.90 per mcf for the nine months ended September 30, 2007. Third quarter North America natural gas production expense increased 18% to $1.03 per mcf from $0.87 per mcf for the third quarter of 2007 and increased 11% from $0.93 per mcf for the prior quarter. The increase in production expense per mcf from the comparable periods in 2007 was primarily a result of lower production volumes on the fixed cost portion of production costs. The increase from the prior quarter was a result of higher repair and maintenance activity during the third quarter of 2008, together with the impact of lower production volumes.

North Sea

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

Offshore West Africa

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

MIDSTREAM

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2008**	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Revenue	**$ 20**	$ 20	$ 19	**$ 60**	$ 55
Production expense	**6**	8	5	**19**	16
Midstream cash flow	**14**	12	14	**41**	39
Depreciation	**2**	2	2	**6**	6
Segment earnings before taxes	**$ 12**	$ 10	$ 12	**$ 35**	$ 33

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			Nine Months Ended	
	Sep 30 2008	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Expense ($ millions)	**$ 657**	$ 668	$ 713	**$ 2,011**	$ 2,138
$/boe (2)	**$ 12.93**	$ 12.88	$ 12.68	**$ 12.89**	$ 12.79

(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 months ended September 30, 2008 and the third quarter decreased in total from the comparable periods in 2007 and the prior quarter, primarily due to the impact of lower sales volumes.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three Months Ended			Nine Months Ended	
	Sep 30 2008	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Expense ($ millions)	**$ 18**	$ 17	$ 18	**$ 52**	$ 53
$/boe [(1)]	**$ 0.35**	$ 0.33	$ 0.32	**$ 0.33**	$ 0.32

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

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time. Accretion expense for the nine months ended September 30, 2008 and the third quarter was consistent with the comparable periods.

ADMINISTRATION EXPENSE

	Three Months Ended			Nine Months Ended	
	Sep 30 2008	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Expense ($ millions)	**$ 46**	$ 45	$ 53	**$ 134**	$ 166
$/boe [(1)]	**$ 0.91**	$ 0.87	$ 0.94	**$ 0.86**	$ 0.99

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

Administration expense for the nine months ended September 30, 2008 and the third quarter decreased in total from the comparable periods in 2007 primarily due to decreased staffing costs, including costs related to the Company's share bonus program, as well as decreased office lease costs.

STOCK-BASED COMPENSATION (RECOVERY) EXPENSE

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2008**	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
(Recovery) expense	**$ (308)**	$ 459	$ 78	**$ 151**	$ 209

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

The Company recorded a $151 million ($107 million after-tax) stock-based compensation expense for the nine months ended September 30, 2008 as a result of normal course graded vesting of options granted in prior periods and the impact of vested options exercised or surrendered during the period, and a $308 million ($221 million after-tax) stock-based compensation recovery primarily due to a 28% decrease in the Company's share price for the three months ended September 30, 2008 (Company's share price as at: September 30, 2008 – C$73.00; June 30, 2008 – C$100.84; December 31, 2007 – C$72.58; September 30, 2007 – C$75.56). As required by GAAP, the Company records a liability for potential cash payments to settle its outstanding employee stock options each reporting period based on the difference between the exercise price of the stock options and the market price of the Company's common shares, pursuant to a graded vesting schedule. The liability is revalued quarterly to reflect changes in the market price of the Company's common shares and the options exercised or surrendered in the period, with the net change recognized in net earnings, or capitalized during the construction period in the case of the Horizon Project. For the nine months ended September 30, 2008, the Company capitalized $33 million in stock-based compensation on the Horizon Project (September 30, 2007 – $63 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, 2008. In periods when substantial stock price changes occur, the Company's earnings are subject to significant volatility. The Company utilizes its stock-based compensation plan to attract and retain employees in a competitive environment. All employees participate in this plan.

For the nine months ended September 30, 2008, the Company paid $202 million for stock options surrendered for cash settlement (September 30, 2007 – $321 million).

INTEREST EXPENSE

	Three Months Ended			Nine Months Ended	
($ millions, except per boe amounts)	**Sep 30 2008**	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Expense, gross	**$ 150**	$ 141	$ 160	**$ 451**	$ 472
Less: capitalized interest, Horizon Project	**125**	110	95	**346**	247
Expense, net	**$ 25**	$ 31	$ 65	**$ 105**	$ 225
$/boe (1)	**$ 0.49**	$ 0.60	$ 1.15	**$ 0.67**	$ 1.34
Average effective interest rate	**5.0%**	4.8%	5.7%	**5.2%**	5.4%

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

Gross interest expense and the Company's average effective interest rate decreased in the nine months ended September 30, 2008 from the comparable periods in 2007 primarily due to decreased short term borrowing rates and the impact of the stronger Canadian dollar.

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

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2008**	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Crude oil and NGLs financial instruments	**$ 792**	$ 944	$ 102	**$ 2,199**	$ 197
Natural gas financial instruments	**16**	10	(125)	**(21)**	(216)
Foreign currency swaps	**(17)**	-	-	**(17)**	-
Realized loss (gain)	**$ 791**	$ 954	$ (23)	**$ 2,161**	$ (19)
Crude oil and NGLs financial instruments	**$ (2,423)**	$ 1,380	$ 80	**$ (992)**	$ 474
Natural gas financial instruments	**(68)**	38	(4)	**29**	81
Foreign currency swaps	**(15)**	(3)	-	**(20)**	-
Unrealized (gain) loss	**$ (2,506)**	$ 1,415	$ 76	**$ (983)**	$ 555
Net (gain) loss	**$ (1,715)**	$ 2,369	$ 53	**$ 1,178**	$ 536

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

	Three Months Ended			Nine Months Ended	
	Sep 30 2008	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Crude oil and NGLs ($/bbl) (1)	**$ 28.37**	$ 32.84	$ 3.30	**$ 25.39**	$ 2.19
Natural gas ($/mcf) (1)	**$ 0.11**	$ 0.07	$ (0.83)	**$ (0.05)**	$ (0.47)

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

Complete details related to outstanding derivative financial instruments at September 30, 2008 are disclosed in note 10 to the Company's unaudited interim consolidated financial statements.

The commodity derivative financial instruments currently outstanding have not been designated as hedges for accounting purposes (the "non-designated hedges"). The fair value of these non-designated hedges is based on prevailing forward commodity prices in effect at the end of each reporting period and is reflected in risk management activities in consolidated net earnings. The cash settlement amount of the risk management derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the derivative financial instruments, as compared to their mark-to-market value at September 30, 2008.

Due to changes in crude oil and natural gas forward pricing and the reversal of prior period unrealized gains and losses, the Company recorded a net unrealized gain of $983 million ($677 million after-tax) on its risk management activities for the nine months ended September 30, 2008, including a $2,506 million ($1,750 million after-tax) net unrealized gain for the third quarter of 2008 (June 30, 2008 – unrealized loss of $1,415 million, $997 million after-tax; September 30, 2007 – unrealized loss of $76 million, $57 million after-tax).

FOREIGN EXCHANGE

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2008**	Jun 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Net realized (gain) loss	**$ (40)**	$ (11)	$ 22	**$ (63)**	$ 53
Net unrealized loss (gain) (1)	**113**	(20)	(195)	**219**	(477)
Net loss (gain)	**$ 73**	$ (31)	$ (173)	**$ 156**	$ (424)

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

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

The net unrealized foreign exchange loss for the nine months ended September 30, 2008 was primarily related to the weakening of the Canadian dollar in relation to the US dollar with respect to the US dollar debt, offset by the impact of the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars. Included in the net unrealized loss for the nine months ended September 30, 2008 was an unrealized gain of $136 million (nine months ended September 30, 2007 – unrealized loss of $335 million) related to the impact of the cross currency swaps. The net realized foreign exchange gain for the nine months ended September 30, 2008 was primarily due to the result of foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US dollar denominated debt. The Canadian dollar ended the third quarter at US$0.9435 compared to US$0.9817 at June 30, 2008 (December 31, 2007 – US$1.0120, September 30, 2007 – US$1.0037.

TAXES

($ millions, except income tax rates)	Three Months Ended Sep 30 2008	Jun 30 2008	Sep 30 2007	Nine Months Ended Sep 30 2008	Sep 30 2007
Current	**$ 52**	$ 96	$ 30	**$ 218**	$ 105
Deferred	**(7)**	(34)	10	**(62)**	27
Taxes other than income tax	**$ 45**	$ 62	$ 40	**$ 156**	$ 132
North America	**$ 6**	$ 6	$ 28	**$ 33**	$ 65
North Sea	**121**	111	56	**328**	145
Offshore West Africa	**44**	34	21	**116**	47
Current income tax	**171**	151	105	**477**	257
Future income tax	**1,011**	(301)	175	**790**	391
	1,182	(150)	280	**1,267**	648
Income tax rate and other legislative changes (1) (2)	**-**	-	-	**41**	71
	$ 1,182	$ (150)	$ 280	**$ 1,308**	$ 719
Effective income tax rate before non-recurring benefits	**29.4%**	30.2%	28.6%	**29.2%**	29.3%

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

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

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

Taxable income from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in 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.

CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended **Sep 30 2008**	Jun 30 2008	Sep 30 2007	Nine Months Ended **Sep 30 2008**	Sep 30 2007
Expenditures on property, plant and equipment					
Net property acquisitions	**$ 47**	$ 263	$ 7	**$ 302**	$ 68
Land acquisition and retention	**32**	24	29	**68**	80
Seismic evaluations	**40**	18	23	**85**	107
Well drilling, completion and equipping	**421**	286	299	**1,159**	1,301
Production and related facilities	**311**	270	238	**900**	815
Total net reserve replacement expenditures	**851**	861	596	**2,514**	2,371
Horizon Project:					
Phase 1 construction costs	**635**	875	671	**2,175**	2,049
Phase 1 operating and capital inventory	**27**	14	-	**82**	-
Phase 1 commissioning costs	**84**	34	-	**167**	-
Phases 2/3 costs	**83**	82	28	**242**	91
Capitalized interest, stock-based compensation and other	**46**	247	120	**402**	329
Total Horizon Project	**875**	1,252	819	**3,068**	2,469
Midstream	**2**	3	2	**6**	4
Abandonments [2]	**10**	7	22	**23**	55
Head office	**6**	4	3	**13**	12
Total net capital expenditures	**$ 1,744**	$ 2,127	$ 1,442	**$ 5,624**	$ 4,911
By segment					
North America	**$ 578**	$ 617	$ 441	**$ 1,858**	$ 1,858
North Sea	**78**	79	121	**202**	395
Offshore West Africa	**195**	164	34	**453**	116
Other	**-**	1	-	**1**	2
Horizon Project	**875**	1,252	819	**3,068**	2,469
Midstream	**2**	3	2	**6**	4
Abandonments [2]	**10**	7	22	**23**	55
Head office	**6**	4	3	**13**	12
Total	**$ 1,744**	$ 2,127	$ 1,442	**$ 5,624**	$ 4,911

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

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

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

Net capital expenditures for the nine months ended September 30, 2008 were $5,624 million compared to $4,911 million for the nine months ended September 30, 2007. Net capital expenditures for the third quarter of 2008 were $1,744 million compared to $1,442 million for the third quarter of 2007 and $2,127 million for the prior quarter. The capital expenditures primarily reflected the continued progress on the Company's larger, future growth projects, most notably the Horizon Project, Primrose East, and Gabon, offset by the effects of an overall strategic reduction in the North America natural gas drilling program.

For the nine months ended September 30, 2008, the Company drilled a total of 790 net wells consisting of 228 natural gas wells, 500 crude oil wells, 34 stratigraphic test and service wells and 28 wells that were dry. This compared to 1,051 net wells drilled for the nine months ended September 30, 2007. The Company achieved an overall success rate of 96% for the nine months ended September 30, 2008, excluding stratigraphic test and service wells, compared to 90% for the nine months ended September 30, 2007.

For the third quarter of 2008, the Company drilled a total of 315 net wells consisting of 62 natural gas wells, 234 crude oil wells, 8 stratigraphic test and service wells and 11 wells that were dry. This compared to 268 net wells drilled for the third quarter of 2007 and 115 net wells for the prior quarter. The Company achieved an overall success rate of 96% for the third quarter of 2008, excluding stratigraphic test and service wells, compared to 95% for the third quarter of 2007 and 94% for the prior quarter.

North America

North America, excluding the Horizon Project, accounted for approximately 34% of the total capital expenditures for the nine months ended September 30, 2008 compared to 39% for the nine months ended September 30, 2007.

During the nine months ended September 30, 2008, the Company targeted 237 net natural gas wells, including 24 wells in Northeast British Columbia, 86 wells in the Northern Plains region, 58 wells in Northwest Alberta, and 69 wells in the Southern Plains region. The Company also targeted 514 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 288 heavy crude oil wells, 92 Pelican Lake crude oil wells, 52 thermal crude oil wells and 6 light crude oil wells were targeted. Another 76 wells targeting light crude oil were drilled outside the Northern Plains region.

Due to significant differences in relative commodity prices between crude oil and natural gas during the nine months ended September 30, 2008, the Company continued to access its large crude oil drilling inventory to maximize value in both the short and long term. Due to the Company's focus on drilling crude oil wells in 2007 and 2008, natural gas drilling activities have been reduced to manage overall capital spending. Deferred natural gas well locations have been retained in the Company's prospect inventory.

As part of the phased expansion of its In-Situ Oil Sands Assets, the Company is continuing to develop its Primrose thermal projects. Overall Primrose thermal production averaged approximately 61,000 bbl/d for the third quarter of 2008 compared to 60,000 bbl/d for the third quarter of 2007 and approximately 67,000 bbl/d for the prior quarter.

The Primrose East Expansion, a new facility located 15 kilometers from the existing Primrose South steam plant and 25 kilometers from the Wolf Lake central processing facility, is anticipated to add approximately 40,000 bbl/d of production capacity when complete. Drilling and construction of facilities is complete. First steaming commenced in September 2008 and first production was achieved in the fourth quarter of 2008.

The next planned phase of the Company's In-Situ Oil Sands Assets expansion is the Kirby project located 120 kilometers north of the existing Primrose facilities. The Kirby project is anticipated to add approximately 45,000 bbl/d of production capacity. During 2007, the Company filed a combined application and Environmental Impact Assessment for this project with Alberta Environment and the Alberta Energy and Utilities Board. Final corporate sanction and project scope will be impacted by environmental regulations and their associated costs.

Development of new pads and secondary recovery conversion projects at Pelican Lake continued as expected throughout the third quarter of 2008. Drilling consisted of 35 horizontal wells in the third quarter. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 37,000 bbl/d for the second and third quarter of 2008 compared to approximately 35,000 bbl/d for the third quarter of 2007.

For the fourth quarter of 2008, the Company's overall planned drilling activity in North America is expected to be comprised of 31 natural gas wells and 222 crude oil wells, excluding stratigraphic and service wells.

Horizon Project

First production of synthetic crude oil is currently targeted to commence late in the fourth quarter of 2008. A high level overview of progress by major plant facility at the Horizon Project is as follows:

- **Mining** – Completed, ready for oil sands mining operation, continues to move overburden;
- **Ore Preparation Plant** – Completed, ready for operation;
- **Hydrotransport** – Completed, ready for operation;
- **Piperack** – Completed, live and operational;
- **Extraction** – Completed, ready for operation;
- **Froth Treatment** – Completed, in commissioning and testing;
- **Delayed Coker / Diluent Recovery Unit** – Completed, circulating diesel and ready for operation;
- **Co-generation** – Completed, producing steam and power;
- **Sulphur Plant** – Completed, turned over to operations for commissioning and testing;
- **Tankage** – Completed, ready for operation;
- **Main Control Room** – Completed, live and operational;
- **Utilities & Services** – Completed, live and operational;
- **SCO Pipeline (third party owned and operated)** – Completed, ready for operation;
- **Hydrogen Plant** – Completed, turned over to operations for commissioning and testing; and
- **Hydrotreaters** – Plant 41 has been completed and turned over to operations for commissioning and testing. Plant 43 is completing electrical heat tracing and insulation while starting commissioning. Plant 42 is mechanically complete with electrical heat tracing and insulation to be completed before turning over to operations for commissioning and testing.

Construction delays and an extended commissioning schedule have lead to an increase of $441 million to the project forecast construction costs. This results in the revised total construction cost estimate for Phase 1 of the Horizon Project to be approximately $9.7 billion.

North Sea

In the third quarter of 2008, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. At the end of the quarter 0.9 net wells were in progress.

The Company also continued with its strategy of long term investment in the facilities and infrastructure at the Ninian and Murchison fields, completing a turnaround at Murchison which included the successful implementation of a new control system. During the third quarter turnarounds were also completed at the T-Block and Banff fields within planned timeframes.

Offshore West Africa

During the third quarter of 2008, 1.5 net wells were drilled, including 0.9 net stratigraphic wells, with an additional 0.6 net wells drilling at the end of the quarter.

At Espoir a workover was successfully completed restoring production to a shut-in well. Another workover was in progress at the end of the quarter. The first well in the current year Baobab drilling program was completed in the quarter and brought on production. At the 90% owned and operated Olowi Field in offshore Gabon the substructure was put in place in readiness for installation of the Conductor Supported Platform, which was installed in early November, and construction continued on the wellhead towers, subsea facilities and the floating production storage and offtake vessel ("FPSO"). Drilling commenced early in the second quarter of 2008 and continued in the third quarter with first crude oil now targeted for the first quarter of 2009 due to delays in the completion of the construction of the FPSO. Olowi production is targeted to plateau at approximately 20,000 bbl/d net to the Company.

Capital Budget and Production Guidance for 2009

The Company has completed its capital and operating budget planning for the 2009 fiscal year and will continue to implement its strategy of maintaining a large portfolio of varied projects, which it believes will enable it, over an extended period of time, to provide consistent growth in production and create shareholder value. In response to the current economic climate, the Company's total forecasted capital spending for 2009 has been reduced to approximately $4.0 billion. Annual production for 2009 is forecasted to average between 386,000 and 426,000 bbl/d of crude oil and NGLs and between 1,285 and 1,350 mmcf/d of natural gas. As necessary, the 2009 budget is subject to revision throughout the upcoming year in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Sep 30 2008**	Jun 30 2008	Dec 31 2007	Sep 30 2007
Working capital deficit (1)	**$ 1,103**	$ 3,180	$ 1,382	$ 824
Long-term debt (2)	**$ 11,633**	$ 11,040	$ 10,940	$ 10,686
Share capital	**$ 2,761**	$ 2,754	$ 2,674	$ 2,663
Retained earnings	**13,628**	10,847	10,575	9,824
Accumulated other comprehensive income	**116**	6	72	85
Shareholders' equity	**$ 16,505**	$ 13,607	$ 13,321	$ 12,572
Debt to book capitalization (2) (3)	**41%**	45%	45%	46%
Debt to market capitalization (2) (4)	**23%**	17%	22%	21%
After tax return on average common shareholders' equity (5)	**29%**	14%	22%	19%
After tax return on average capital employed (2) (6)	**16%**	8%	12%	11%

(1) Calculated as current assets less current liabilities.

(2) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and transaction costs.

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

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

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

(6) Calculated as net earnings plus after-tax interest expense for the twelve month trailing period; as a percentage of average capital employed for the period. Average capital employed is the average shareholders' equity and long-term debt for the period, including $9,725 million in average capital employed related to the Horizon Project (June 30, 2008 – $8,781 million; December 31, 2007 – $7,001 million; September 30, 2007 – $6,120 million).

At September 30, 2008, the Company's capital resources consisted primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash flow from operations is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's December 31, 2007 annual MD&A**.** The Company's ability to renew existing credit facilities and raise new debt is also dependent upon these factors, as well as maintaining an investment grade debt rating and the condition of capital and credit markets.

The current worldwide credit events has resulted in unprecedented disruptions in the availability of credit on commercially acceptable terms. In light of these credit challenges, the Company has undertaken a thorough review of its liquidity sources as well as its exposure to counterparties and has concluded that its capital resources are sufficient to meet ongoing short, medium and long-term commitments. Specifically, the Company continues to believe that its internally generated cash flow from operations supported by the implementation of its hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing credit facilities and its ability to raise new debt on commercially acceptable terms, will provide sufficient liquidity to sustain its operations in the short, medium and long-term and support its growth strategy. Further, the Company believes that its counterparties currently have the financial capacity to settle outstanding obligations in the normal course of business.

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

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

At the end of the third quarter of 2008, the Company had $2,373 million of available credit under its bank credit facilities, which together with net cash flow to be generated in 2009, is forecasted to be sufficient to repay the October 2009 maturity of the $2,350 million non-revolving bank credit facility. Further, the Company's current debt ratings are BBB (high) with a negative trend by DBRS Limited, Baa2 with a stable outlook by Moody's Investors Service and BBB with a stable outlook by Standard & Poor's. The Company does not have any direct exposure to asset-backed commercial paper.

Further details related to the Company's long-term debt at September 30, 2008 are disclosed in note 3 to the Company's unaudited interim consolidated financial statements.

At September 30, 2008, the Company's working capital deficit was $1,103 million and included the current portion of the stock-based compensation liability of $378 million and the current portion of the net mark-to-market liability for risk management derivative financial instruments of $330 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, 2008.

The financing of Phase 1 of the Horizon Project development was guided by the competing principles of retaining as much direct ownership interest as possible while maintaining a strong balance sheet. 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.

Long-term debt was $11,633 million at September 30, 2008, resulting in a debt to book capitalization ratio of 41% (June 30, 2008 – 45%; December 31, 2007 – 45%; September 30, 2007 – 46%). As expected, this ratio is now near the midpoint of the 35% to 45% range targeted by management primarily due to the net earnings contribution for the year and the impact of the strengthening US dollar exchange rate on the Company's US dollar denominated long-term debt. The Company remains committed to maintaining a strong balance sheet and flexible capital structure. While the Company believes that it has the balance sheet strength and flexibility to complete the Horizon Project, as well as its other planned capital expenditure programs, the Company has hedged a portion of its crude oil and natural gas production for 2008 and 2009 at prices that protect investment returns. In the future, the Company may also consider the divestiture of certain non-strategic and non-core properties to gain additional balance sheet flexibility.

The Company's commodity hedging program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures throughout the Horizon Project construction period. This program currently allows for the hedging of up to 75% of the production for the remainder of 2008. For the purpose of this program, the purchase of put options is in addition to the above parameters. In accordance with the policy, approximately 49% of budgeted crude oil volumes are hedged using collars for the remainder of 2008. In addition, 50,000 bbl/d of crude oil volumes are protected by put options for the remainder of 2008 at a strike price of US$55.00 per bbl.

Commencing January 1, 2009, the Company's commodity hedging program has been revised by its Board of Directors to allow for the hedging of up to 50% of the near 12 months budgeted production and up to 25% of the following 13 to 24 months estimated production. The purchase of put options will continue to be in addition to the above parameters. In 2009, approximately 6% of estimated crude oil volumes are hedged using collars and 92,000 bbl/d of crude oil volumes are protected by put options at a strike price of US$100.00 per bbl.

The Company has the following commodity related net financial derivatives outstanding at September 30, 2008:

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Crude oil price collars	Oct 2008	–	Dec 2008	20,000 bbl/d	US$50.00	–	US$65.53	Mayan Heavy
	Oct 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$75.22	WTI
	Oct 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.05	WTI
	Oct 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.98	WTI
	Oct 2008	–	Dec 2008	25,000 bbl/d	US$70.00	–	US$112.63	WTI
	Jan 2009	–	Dec 2009	25,000 bbl/d	US$70.00	–	US$111.56	WTI
Crude oil puts	Oct 2008	–	Dec 2008	50,000 bbl/d			US$55.00	WTI
	Jan 2009	–	Dec 2009	92,000 bbl/d			US$100.00	WTI

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

Subsequent to September 30, 2008, the Company entered into 4,000 bbl/d of US$70.00 – US$90.00 WTI collars for the period April 2009 to June 2009. In addition, the Company entered into 500,000 GJ/d of natural gas AECO collars with a floor of C$6.00 and a ceiling ranging from C$8.50 to C$8.80 for the period November 2008 to March 2009.

Long-term debt

As at September 30, 2008, the Company had in place unsecured bank credit facilities of $6,233 million, comprised of:

- a $125 million demand credit facility;
- a non-revolving syndicated credit facility of $2,350 million maturing October 2009;
- a revolving syndicated credit facility of $2,230 million maturing June 2012;
- a revolving syndicated credit facility of $1,500 million maturing June 2012; and
- a £15 million demand credit facility related to the Company's North Sea operations.

The revolving syndicated credit facilities are extendible annually for one year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date.

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $367 million, including $300 million related to the Horizon Project, were outstanding at September 30, 2008.

Medium-term notes

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

Senior unsecured notes

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

US dollar debt securities

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

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

Share capital

As at September 30, 2008, there were 540,857,000 common shares outstanding and 25,161,000 stock options outstanding. As at November 4, 2008, the Company had 540,885,000 common shares outstanding and 24,958,000 stock options outstanding.

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

Commitments and off balance sheet arrangements

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. These commitments primarily relate to debt repayments; operating leases relating to offshore FPSOs, drilling rigs and office space; firm commitments for gathering, processing and transmission services; as well as expenditures relating to asset retirement obligations. As at September 30, 2008, 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, 2008:

($ millions)	Remaining 2008	2009	2010	2011	2012	Thereafter
Product transportation and pipeline	$ 61	$ 181	$ 164	$ 135	$ 114	$ 1,101
Offshore equipment operating lease (1)	$ 51	$ 134	$ 121	$ 119	$ 96	$ 425
Offshore drilling (2) (3)	$ 85	$ 218	$ 54	$ -	$ -	$ -
Asset retirement obligations (4)	$ 10	$ 4	$ 5	$ 4	$ 4	$ 4,614
Long-term debt (5)	$ -	$ 2,379	$ 400	$ 424	$ 371	$ 6,683
Interest expense (6)	$ 122	$ 589	$ 518	$ 496	$ 438	$ 5,569
Office lease	$ 6	$ 26	$ 29	$ 22	$ 2	$ -
Other	$ 50	$ 380	$ 260	$ 36	$ 30	$ 74

(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 2009, 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 commenced in the third quarter of 2008, on delivery of the rig. Estimated total remaining payments of US$54 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 remaining payments of US$279 million have been included in this table for the period 2008 – 2010.

(4) Amounts represent management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2008 – 2012 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(5) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,440 million of revolving bank credit facilities due to the extendable nature of the facilities.

(6) Interest expense amounts represent the scheduled fixed-rate and variable-rate cash payments related to long-term debt. Interest on variable-rate long-term debt was estimated based upon prevailing interest rates as at September 30, 2008.

In addition to the amounts disclosed above, the Company has budgeted revised construction costs of approximately $785 million related to the planned completion of Phase 1 of the Horizon Project.

Legal proceedings

The Company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. In addition, the Company is subject to certain contractor construction claims related to the Horizon Project. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

Critical accounting estimates and change in accounting policies

The preparation of financial statements requires the Company to make judgements, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. Actual results could differ from those estimates. A comprehensive discussion of the Company's significant accounting policies is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2007.

For the impact of new accounting standards related to capital disclosures, inventory and financial instruments, refer to note 2 of the unaudited interim consolidated financial statements as at September 30, 2008.

International Financial Reporting Standards

In February 2008, the Canadian Institute of Chartered Accountants confirmed that effective January 1, 2011, Canadian GAAP for publicly accountable entities will be replaced in full with International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board. The Company is currently assessing the impact of adopting IFRS and is developing a plan to achieve convergence to IFRS by January 1, 2011.

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 2008, excluding mark-to-market gains (losses) on risk management activities and capitalized interest, and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

	Cash flow from operations ($ millions)	Cash flow from operations (per common share, basic)	Net earnings ($ millions)	Net earnings (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl [(1)]				
Excluding financial derivatives	$ 89	$ 0.17	$ 66	$ 0.12
Including financial derivatives	$ 63	$ 0.12	$ 47	$ 0.09
Natural gas – AECO C$0.10/mcf [(1)]				
Excluding financial derivatives	$ 40	$ 0.07	$ 28	$ 0.05
Including financial derivatives	$ 39	$ 0.07	$ 28	$ 0.05
Volume changes				
Crude oil – 10,000 bbl/d	$ 234	$ 0.43	$ 146	$ 0.27
Natural gas – 10 mmcf/d	$ 23	$ 0.04	$ 11	$ 0.02
Foreign currency rate change				
$0.01 change in US$ [(1)]				
Including financial derivatives	$ 94 – 96	$ 0.17 – 0.18	$ 26	$ 0.05
Interest rate change – **1%**	$ 32	$ 0.06	$ 32	$ 0.06

(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

($/boe) [1]	Three Months Ended Sep 30 2008	Jun 30 2008	Sep 30 2007	Nine Months Ended Sep 30 2008	Sep 30 2007
Sales price [2]	**$ 80.60**	$ 84.88	$ 47.96	**$ 76.73**	$ 48.99
Royalties	**12.06**	13.26	6.07	**11.22**	6.27
Production expense [3]	**12.52**	11.60	9.62	**11.70**	10.05
Netback	**56.02**	60.02	32.27	**53.81**	32.67
Midstream contribution [3]	**(0.28)**	(0.24)	(0.26)	**(0.26)**	(0.23)
Administration	**0.91**	0.87	0.94	**0.86**	0.99
Interest, net	**0.49**	0.60	1.15	**0.67**	1.34
Realized risk management loss (gain)	**15.56**	18.38	(0.41)	**13.86**	(0.11)
Realized foreign exchange (gain) loss	**(0.80)**	(0.20)	0.38	**(0.41)**	0.31
Taxes other than income tax – current	**1.02**	1.84	0.54	**1.40**	0.62
Current income tax – North America	**0.09**	0.11	0.49	**0.21**	0.38
Current income tax – North Sea	**2.39**	2.15	0.99	**2.11**	0.87
Current income tax – Offshore West Africa	**0.87**	0.65	0.37	**0.74**	0.28
Cash flow	**$ 35.77**	$ 35.86	$ 28.08	**$ 34.63**	$ 28.22

(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 2008**	Dec 31 2007
ASSETS		
Current assets		
Cash and cash equivalents	**$ 14**	$ 21
Accounts receivable and other	**1,967**	1,662
Future income tax	**194**	480
Current portion of other long-term assets	**-**	18
	2,175	2,181
Property, plant and equipment (note 12)	**37,628**	33,902
Other long-term assets	**26**	31
	$ 39,829	$ 36,114
LIABILITIES		
Current liabilities		
Accounts payable	**$ 408**	$ 379
Accrued liabilities	**2,091**	1,567
Current portion of other long-term liabilities (note 4)	**779**	1,617
	3,278	3,563
Long-term debt (note 3)	**11,633**	10,940
Other long-term liabilities (note 4)	**1,282**	1,561
Future income tax	**7,131**	6,729
	23,324	22,793
SHAREHOLDERS' EQUITY		
Share capital (note 6)	**2,761**	2,674
Retained earnings	**13,628**	10,575
Accumulated other comprehensive income (note 7)	**116**	72
	16,505	13,321
	$ 39,829	$ 36,114

Commitments (note 11)

Consolidated Statements of Earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended Sep 30 2008	Three Months Ended Sep 30 2007	Nine Months Ended Sep 30 2008	Nine Months Ended Sep 30 2007
Revenues	**$ 4,583**	$ 3,073	**$ 13,662**	$ 9,343
Less: royalties	**(612)**	(341)	**(1,749)**	(1,048)
Revenue, net of royalties	**3,971**	2,732	**11,913**	8,295
Expenses				
Production	**639**	544	**1,836**	1,693
Transportation and blending	**472**	359	**1,646**	1,103
Depletion, depreciation and amortization	**659**	715	**2,017**	2,144
Asset retirement obligation accretion (note 4)	**18**	18	**52**	53
Administration	**46**	53	**134**	166
Stock-based compensation (recovery) expense (note 4)	**(308)**	78	**151**	209
Interest, net	**25**	65	**105**	225
Risk management activities (note 10)	**(1,715)**	53	**1,178**	536
Foreign exchange loss (gain)	**73**	(173)	**156**	(424)
	(91)	1,712	**7,275**	5,705
Earnings before taxes	**4,062**	1,020	**4,638**	2,590
Taxes other than income tax	**45**	40	**156**	132
Current income tax expense (note 5)	**171**	105	**477**	257
Future income tax expense (note 5)	**1,011**	175	**790**	391
Net earnings	**$ 2,835**	$ 700	**$ 3,215**	$ 1,810
Net earnings per common share (note 9)				
Basic and diluted	**$ 5.25**	$ 1.30	**$ 5.95**	$ 3.36

Consolidated Statements of Shareholders' Equity

(millions of Canadian dollars, unaudited)	Nine Months Ended Sep 30 2008	Sep 30 2007
Share capital (note 6)		
Balance – beginning of period	**$ 2,674**	$ 2,562
Issued upon exercise of stock options	**17**	19
Previously recognized liability on stock options exercised for common shares	**70**	82
Balance – end of period	**2,761**	2,663
Retained earnings		
Balance – beginning of period	**10,575**	8,151
Net earnings	**3,215**	1,810
Dividends on common shares (note 6)	**(162)**	(137)
Balance – end of period	**13,628**	9,824
Accumulated other comprehensive income (note 7)		
Balance – beginning of period	**72**	146
Other comprehensive income (loss), net of taxes	**44**	(61)
Balance – end of period	**116**	85
Shareholders' equity	**$ 16,505**	$ 12,572

Consolidated Statements of Comprehensive Income

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2008	Sep 30 2007	Nine Months Ended Sep 30 2008	Sep 30 2007
Net earnings	**$ 2,835**	$ 700	**$ 3,215**	$ 1,810
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income during the period, net of taxes of $13 million (2007 - $1 million) – three months ended; $2 million (2007 - $9 million) – nine months ended	**89**	10	**24**	6
Reclassification to net earnings, net of taxes of $1 million (2007 - $11 million) – three months ended; $6 million (2007 - $24 million) – nine months ended	**3**	24	**(11)**	(51)
	92	34	**13**	(45)
Foreign currency translation adjustment				
Translation of net investment	**18**	(11)	**31**	(16)
Other comprehensive income (loss), net of taxes	**110**	23	**44**	(61)
Comprehensive income	**$ 2,945**	$ 723	**$ 3,259**	$ 1,749

Consolidated Statements of Cash Flows

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2008	Three Months Ended Sep 30 2007	Nine Months Ended Sep 30 2008	Nine Months Ended Sep 30 2007
Operating activities				
Net earnings	**$ 2,835**	$ 700	**$ 3,215**	$ 1,810
Non-cash items				
Depletion, depreciation and amortization	**659**	715	**2,017**	2,144
Asset retirement obligation accretion	**18**	18	**52**	53
Stock-based compensation (recovery) expense	**(308)**	78	**151**	209
Unrealized risk management (gain) loss	**(2,506)**	76	**(983)**	555
Unrealized foreign exchange loss (gain)	**113**	(195)	**219**	(477)
Deferred petroleum revenue tax (recovery) expense	**(7)**	10	**(62)**	27
Future income tax expense	**1,011**	175	**790**	391
Other	**4**	12	**23**	7
Abandonment expenditures	**(10)**	(22)	**(23)**	(55)
Net change in non-cash working capital	**(132)**	(94)	**16**	(82)
	1,677	1,473	**5,415**	4,582
Financing activities				
Issue (repayment) of bank credit facilities, net	**331**	49	**(909)**	(1,797)
Repayment of medium-term notes	**-**	-	**-**	(125)
Repayment of senior unsecured notes	**-**	-	**(31)**	(33)
(Repayment) issue of US dollar debt securities	**(8)**	-	**1,215**	2,553
Issue of common shares on exercise of stock options	**3**	3	**17**	19
Dividends on common shares	**(54)**	(46)	**(154)**	(132)
Net change in non-cash working capital	**(32)**	(17)	**(2)**	6
	240	(11)	**136**	491
Investing activities				
Expenditures on property, plant and equipment	**(1,739)**	(1,421)	**(5,616)**	(4,861)
Net proceeds on sale of property, plant and equipment	**5**	1	**15**	5
Net expenditures on property, plant and equipment	**(1,734)**	(1,420)	**(5,601)**	(4,856)
Net change in non-cash working capital	**(191)**	(32)	**43**	(219)
	(1,925)	(1,452)	**(5,558)**	(5,075)
(Decrease) increase in cash and cash equivalents	**(8)**	10	**(7)**	(2)
Cash and cash equivalents – beginning of period	**22**	11	**21**	23
Cash and cash equivalents – end of period	**$ 14**	$ 21	**$ 14**	$ 21
Interest paid	**$ 184**	$ 158	**$ 462**	$ 403
Taxes paid				
Taxes other than income tax	**$ 162**	$ 29	**$ 217**	$ 103
Current income tax	**$ 178**	$ 85	**$ 123**	$ 157

Notes to the consolidated financial statements

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

1. ACCOUNTING POLICIES

The interim consolidated financial statements of Canadian Natural Resources Limited (the "Company") include the Company and all of its subsidiaries and partnerships, and have been prepared following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2007, except as described in note 2. The interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2007.

Comparative Figures

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

2. CHANGES IN ACCOUNTING POLICIES

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

- **Capital Disclosures** – Section 1535 – "Capital Disclosures" requires entities to disclose their objectives, policies and processes for managing capital, as well as quantitative data about capital. The standard also requires the disclosure of any externally imposed capital requirements and compliance with those requirements. The standard does not define capital. This standard affects disclosure only and did not impact the Company's accounting for capital (note 8).
- **Inventories** – Section 3031 – "Inventories" replaces Section 3030 – "Inventories" and establishes new standards for the measurement of cost of inventories and expands disclosure requirements for inventories. Adoption of this standard did not have a material impact on the Company's financial statements.
- **Financial Instruments** – Section 3862 – "Financial Instruments – Disclosure" and Section 3863 – "Financial Instruments – Presentation" replace Section 3861 – "Financial Instruments – Disclosure and Presentation". Section 3862 enhances disclosure requirements concerning risks and requires quantitative and qualitative disclosures about exposures to risks arising from financial instruments. Section 3863 carries forward the presentation requirements from Section 3861 unchanged. These standards affect disclosures only and do not impact the Company's accounting for financial instruments (note 10).

3. LONG–TERM DEBT

		Sep 30 2008		Dec 31 2007
Canadian dollar denominated debt				
Bank credit facilities (bankers' acceptances)	**$**	**3,787**	$	4,696
Medium-term notes		**1,200**		1,200
		4,987		5,896
US dollar denominated debt				
Senior unsecured notes (2008 - US$31 million; 2007 - US$62 million)		**33**		61
US dollar debt securities (2008 - US$6,300 million; 2007 - US$5,108 million)		**6,677**		5,048
Less – original issue discount on senior unsecured notes and US dollar debt securities (1)		**(24)**		(23)
		6,686		5,086
Fair value of interest rate swaps on US dollar debt securities (2)		**16**		9
		6,702		5,095
Long-term debt before transaction costs		**11,689**		10,991
Less – transaction costs (1) (3)		**(56)**		(51)
	$	**11,633**	$	10,940

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

(2) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $16 million (2007 – $9 million) to reflect the fair value impact of hedge accounting.

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

Bank credit facilities

As at September 30, 2008, the Company had in place unsecured bank credit facilities of $6,233 million, comprised of:

- a $125 million demand credit facility;
- a non-revolving syndicated credit facility of $2,350 million maturing October 2009;
- a revolving syndicated credit facility of $2,230 million maturing June 2012;
- a revolving syndicated credit facility of $1,500 million maturing June 2012; and
- a £15 million demand credit facility related to the Company's North Sea operations.

The revolving syndicated credit facilities are extendible annually for one year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date.

The weighted average interest rate of the bank credit facilities outstanding at September 30, 2008, was 3.7% (December 31, 2007 – 5.2%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $367 million, including $300 million related to the Horizon Oil Sands Project ("Horizon Project"), were outstanding at September 30, 2008.

Medium-term notes

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

Senior unsecured notes

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

US dollar debt securities

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

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

4. OTHER LONG–TERM LIABILITIES

	Sep 30 2008	Dec 31 2007
Asset retirement obligations	**$ 1,151**	$ 1,074
Stock-based compensation	**441**	529
Risk management (note 10)	**349**	1,474
Other	**120**	101
	2,061	3,178
Less: current portion	**779**	1,617
	$ 1,282	$ 1,561

Asset retirement obligations

At September 30, 2008, the Company's total estimated undiscounted costs to settle its asset retirement obligations were approximately $4,641 million (December 31, 2007 – $4,426 million). These costs will be incurred over the lives of the operating assets and have been discounted using a weighted average credit-adjusted risk free rate of 6.6% (December 31, 2007 – 6.6%). A reconciliation of the discounted asset retirement obligations is as follows:

	Nine Months Ended Sep 30, 2008	Year Ended Dec 31, 2007
Balance – beginning of period	**$ 1,074**	$ 1,166
Liabilities incurred	**15**	21
Liabilities acquired (disposed)	**3**	(65)
Liabilities settled	**(23)**	(71)
Asset retirement obligation accretion	**52**	70
Revision of estimates	**-**	35
Foreign exchange	**30**	(82)
Balance – end of period	**$ 1,151**	$ 1,074

Stock-based compensation

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

	Nine Months Ended Sep 30, 2008	Year Ended Dec 31, 2007
Balance – beginning of period	$ 529	$ 744
Stock-based compensation	151	193
Payments for options surrendered	(202)	(375)
Transferred to common shares	(70)	(91)
Capitalized to Horizon Project	33	58
Balance – end of period	441	529
Less: current portion	378	390
	$ 63	$ 139

5. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2008	Sep 30 2007	Sep 30 2008	Sep 30 2007
Current income tax – North America	$ 6	$ 28	$ 33	$ 65
Current income tax – North Sea	121	56	328	145
Current income tax – Offshore West Africa	44	21	116	47
Current income tax expense	171	105	477	257
Future income tax expense	1,011	175	790	391
Income tax expense	$ 1,182	$ 280	$ 1,267	$ 648

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

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

6. SHARE CAPITAL

Issued Common shares	Nine Months Ended Sep 30, 2008 Number of shares (thousands)	Amount
Balance – beginning of period	**539,729**	**$ 2,674**
Issued upon exercise of stock options	**1,128**	**17**
Previously recognized liability on stock options exercised for common shares	**-**	**70**
Balance – end of period	**540,857**	**$ 2,761**

Dividend policy

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

Stock options

	Nine Months Ended Sep 30, 2008 Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of period	**30,659**	**$ 47.23**
Granted	**1,327**	**$ 87.19**
Surrendered for cash settlement	**(3,560)**	**$ 25.87**
Exercised for common shares	**(1,128)**	**$ 14.83**
Forfeited	**(2,137)**	**$ 55.63**
Outstanding – end of period	**25,161**	**$ 53.09**
Exercisable – end of period	**6,683**	**$ 37.67**

7. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Sep 30 2008	Sep 30 2007
Derivative financial instruments designated as cash flow hedges	**$ 114**	$ 114
Foreign currency translation adjustment	**2**	(29)
	$ 116	$ 85

8. CAPITAL DISCLOSURES

As required by Canadian generally accepted accounting principles ("GAAP"), effective January 1, 2008, the Company must provide certain disclosures regarding its objectives, policies and processes for managing capital, as well as provide certain quantitative data about capital. As the Company does not have any externally imposed capital requirements, for the purposes of this disclosure, the Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived non-GAAP financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of long-term debt divided by the sum of the carrying value of shareholders' equity plus long-term debt. The Company aims over time to maintain its debt to book capitalization ratio in the range of 35% to 45%. However, the Company may exceed the high end of such target range if it is investing in capital projects, undertaking acquisitions, or in periods of lower commodity prices. The Company may be below the low end of the target range when cash flow from operating activities is greater than current investment activities. The ratio is currently near the midpoint of the target range primarily due to the debt financing of the construction of the Horizon project, together with the impact of the strengthening in the US dollar exchange rate on the Company's US dollar denominated long-term debt.

Readers are cautioned that as the debt to book capitalization ratio has no defined meaning under GAAP, this financial measure may not be comparable to similar measures provided by other reporting entities. Further, there can be no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure at some point in the future.

	Sep 30 2008	Dec 31 2007
Long-term debt	**$ 11,633**	$ 10,940
Total shareholders' equity	**$ 16,505**	$ 13,321
Debt to book capitalization	**41%**	45%

9. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Nine Months Ended	
	Sep 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Weighted average common shares outstanding (thousands) – basic and diluted	**540,819**	539,494	**540,557**	539,229
Net earnings – basic and diluted	**$ 2,835**	$ 700	**$ 3,215**	$ 1,810
Net earnings per common share – basic and diluted	**$ 5.25**	$ 1.30	**$ 5.95**	$ 3.36

10. FINANCIAL INSTRUMENTS

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

	Sep 30, 2008		
Asset (liability)	Loans and receivables at amortized cost	Held for trading at fair value	Other financial liabilities at amortized cost
Cash and cash equivalents	$ -	$ 14	$ -
Accounts receivable	1,344	-	-
Accounts payable	-	-	(408)
Accrued liabilities	-	-	(2,091)
Risk management	-	(349)	-
Long-term debt	-	-	(11,633)
	$ 1,344	$ (335)	$ (14,132)

	Dec 31, 2007		
Asset (liability)	Loans and receivables at amortized cost	Held for trading at fair value	Other financial liabilities at amortized cost
Cash and cash equivalents	$ -	$ 21	$ -
Accounts receivable	1,143	-	-
Accounts payable	-	-	(379)
Accrued liabilities	-	-	(1,567)
Risk management	-	(1,474)	-
Long-term debt	-	-	(10,940)
	$ 1,143	$ (1,453)	$ (12,886)

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

	Sep 30, 2008		Dec 31, 2007	
	Carrying value	Fair value	Carrying value	Fair value
Fixed-rate long-term debt (1)	$ 7,846	$ 6,961	$ 6,244	$ 6,259

(1) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $16 million (2007 – $9 million) to reflect the fair value impact of hedge accounting.

Risk management

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

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

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

	Nine Months Ended Sep 30, 2008	Year Ended Dec 31, 2007
Asset (liability)	**Risk management mark-to-market**	Risk management mark-to-market
Balance – beginning of period	**$ (1,474)**	$ 128
Retained earnings effect of adoption of financial instrument standards	**-**	14
Net cost of outstanding put options	**272**	58
Net change in fair value of outstanding derivative financial instruments attributable to:		
- Risk management activities	**983**	(1,400)
- Interest expense	**7**	9
- Foreign exchange	**136**	(350)
- Other comprehensive income	**3**	125
	(73)	(1,416)
Add: Put premium financing obligations (1)	**(276)**	(58)
Balance – end of period	**(349)**	(1,474)
Less: current portion	**(330)**	(1,227)
	$ (19)	$ (247)

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

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

	Three Months Ended		Nine Months Ended	
	Sep 30 2008	Sep 30 2007	**Sep 30 2008**	Sep 30 2007
Net realized risk management loss (gain)	**$ 791**	$ (23)	**$ 2,161**	$ (19)
Net unrealized risk management (gain) loss	**(2,506)**	76	**(983)**	555
	$ (1,715)	$ 53	**$ 1,178**	$ 536

Financial risk factors

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

Commodity price risk

The Company uses commodity price financial derivatives to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production. At September 30, 2008, the Company had the following net financial derivatives outstanding to manage its commodity price exposures:

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Crude oil price collars	Oct 2008	–	Dec 2008	20,000 bbl/d	US$50.00	–	US$65.53	Mayan Heavy
	Oct 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$75.22	WTI
	Oct 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.05	WTI
	Oct 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.98	WTI
	Oct 2008	–	Dec 2008	25,000 bbl/d	US$70.00	–	US$112.63	WTI
	Jan 2009	–	Dec 2009	25,000 bbl/d	US$70.00	–	US$111.56	WTI
Crude oil puts	Oct 2008	–	Dec 2008	50,000 bbl/d			US$55.00	WTI
	Jan 2009	–	Dec 2009	92,000 bbl/d			US$100.00	WTI

At September 30, 2008, the net cost of outstanding put options and their respective periods of settlement was as follows:

	Q4 2008	Q1 2009	Q2 2009	Q3 2009	Q4 2009
Cost ($ millions)	US$15	US$60	US$60	US$61	US$61

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

Subsequent to September 30, 2008, the Company entered into 4,000 bbl/d of US$70.00 – US$90.00 WTI collars for the period April 2009 to June 2009. In addition, the Company entered into 500,000 GJ/d of natural gas AECO collars with a floor of C$6.00 and a ceiling ranging from C$8.50 to C$8.80 for the period November 2008 to March 2009.

Interest rate risk

The Company is exposed to interest rate risk on its fixed and floating rate long-term debt. The Company enters into interest rate swap agreements to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At September 30, 2008, the Company had the following interest rate swap contracts outstanding:

	Remaining term			Amount ($ millions)	Fixed rate	Floating rate
Interest rate						
Swaps – fixed to floating[(2)]	Oct 2008	–	Oct 2012	US$350	5.45%	LIBOR [(1)] + 0.81%
	Oct 2008	–	Dec 2014	US$350	4.90%	LIBOR [(1)] + 0.38%

(1) London Interbank Offered Rate

(2) Subsequent to September 30, 2008, the Company unwound US$350 million of 5.45% interest rate swaps for net proceeds of approximately US$16 million

All interest rate related derivative financial instruments designated as hedges at September 30, 2008 were classified as fair value hedges.

Foreign currency exchange rate risk

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies in its subsidiaries and in the carrying value of its self-sustaining foreign subsidiaries. The Company periodically enters into cross currency swap agreements and foreign currency forward agreements to manage known currency exposure on US dollar denominated long-term debt and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At September 30, 2008, the Company had the following cross currency swap contracts outstanding:

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

All cross currency related derivative financial instruments designated as hedges at September 30, 2008 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, the Company utilizes foreign currency forward contracts to manage certain foreign currency cash management needs. At September 30, 2008, the Company had US$776 million of these contracts outstanding, with terms of approximately 30 days or less.

Financial instrument sensitivities

As required by Canadian GAAP, the Company must provide certain quantitative sensitivities related to its financial instruments. The following table summarizes the annualized sensitivities of the Company's net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at September 30, 2008 resulting from changes in the specified variable, with all other variables held constant. These sensitivities are limited to the impact of changes in a specified variable applied to financial instruments only and do not represent the impact of a change in the variable on the operating results of the Company taken as a whole. Further, these sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities. In addition, changes in fair value generally can not be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

	Impact on net earnings	Impact on other comprehensive income
Commodity price risk		
Increase WTI US$1.00/bbl	$ (25)	$ -
Decrease WTI US$1.00/bbl	$ 25	$ -
Interest rate risk		
Increase interest rate 1%	$ (26)	$ 7
Decrease interest rate 1%	$ 26	$ (8)
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$ (32)	$ -
Decrease exchange rate by US$0.01	$ 32	$ -

b) Credit risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss for the Company by failing to discharge an obligation.

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. Substantially all of the Company's accounts receivables are due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with substantially all investment grade financial institutions and other entities. At September 30, 2008, the Company had net risk management assets of $111 million with specific counterparties related to derivative financial instruments (December 31, 2007 – $20 million).

c) Liquidity risk

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

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

The maturity dates for financial liabilities are as follows:

		Less than 1 year		1 to less than 2 years		2 to less than 5 years		Thereafter
Accounts payable	$	408	$	-	$	-	$	-
Accrued liabilities	$	2,091	$	-	$	-	$	-
Risk management	$	330	$	(36)	$	27	$	28
Long-term debt (1)	$	33	$	2,346	$	2,019	$	5,859

(1) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,440 million of revolving bank credit facilities due to the extendable nature of the facilities.

11. COMMITMENTS

As at September 30, 2008, the Company had committed to certain payments as follows:

		Remaining 2008		2009		2010		2011		2012		Thereafter
Product transportation and pipeline	$	61	$	181	$	164	$	135	$	114	$	1,101
Offshore equipment operating leases (1)	$	51	$	134	$	121	$	119	$	96	$	425
Offshore drilling (2) (3)	$	85	$	218	$	54	$	-	$	-	$	-
Asset retirement obligations (4)	$	10	$	4	$	5	$	4	$	4	$	4,614
Office leases	$	6	$	26	$	29	$	22	$	2	$	-
Other	$	50	$	380	$	260	$	36	$	30	$	74

(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 2009, 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 commenced in the second quarter of 2008, on delivery of the rig. Estimated total remaining payments of US$54 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 remaining payments of US$279 million have been included in this table for the period 2008 – 2010.

(4) Amounts represent management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2008 – 2012 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

In addition to the amounts disclosed above, the Company has budgeted revised construction costs of approximately $785 million related to the planned completion of Phase 1 of the Horizon Project.

12. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America				North Sea				Offshore West Africa			
	Three Months Ended 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	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007
Segmented revenue	**3,883**	2,459	**11,380**	7,578	**462**	397	**1,507**	1,230	**234**	211	**758**	516
Less: royalties	**(561)**	(320)	**(1,617)**	(1,001)	**(1)**	(1)	**(3)**	(2)	**(50)**	(20)	**(129)**	(45)
Segmented revenue, net of royalties	**3,322**	2,139	**9,763**	6,577	**461**	396	**1,504**	1,228	**184**	191	**629**	471
Segmented expenses												
Production	**498**	401	**1,424**	1,265	**123**	117	**340**	353	**15**	23	**61**	63
Transportation and blending	**483**	366	**1,674**	1,122	**3**	4	**8**	12	**1**	-	**1**	-
Depletion, depreciation and amortization	**556**	593	**1,684**	1,748	**75**	77	**233**	271	**26**	43	**94**	119
Asset retirement obligation accretion	**12**	9	**32**	28	**6**	8	**19**	23	**-**	1	**1**	2
Realized risk management loss (gain)	**791**	(28)	**2,162**	(53)	**-**	5	**(1)**	34	**-**	-	**-**	-
Total segmented expenses	**2,340**	1,341	**6,976**	4,110	**207**	211	**599**	693	**42**	67	**157**	184
Segmented earnings before the following	**982**	798	**2,787**	2,467	**254**	185	**905**	535	**142**	124	**472**	287
Non-segmented expenses												
Administration												
Stock-based compensation (recovery) expense												
Interest, net												
Unrealized risk management (gain) loss												
Foreign exchange loss (gain)												
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	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007
Segmented revenue	**20**	19	**60**	55	**(16)**	(13)	**(43)**	(36)	**4,583**	3,073	**13,662**	9,343
Less: royalties	**-**	-	**-**	-	**-**	-	**-**	-	**(612)**	(341)	**(1,749)**	(1,048)
Segmented revenue, net of royalties	**20**	19	**60**	55	**(16)**	(13)	**(43)**	(36)	**3,971**	2,732	**11,913**	8,295
Segmented expenses												
Production	**6**	5	**19**	16	**(3)**	(2)	**(8)**	(4)	**639**	544	**1,836**	1,693
Transportation and blending	**-**	-	**-**	-	**(15)**	(11)	**(37)**	(31)	**472**	359	**1,646**	1,103
Depletion, depreciation and amortization	**2**	2	**6**	6	**-**	-	**-**	-	**659**	715	**2,017**	2,144
Asset retirement obligation accretion	**-**	-	**-**	-	**-**	-	**-**	-	**18**	18	**52**	53
Realized risk management loss (gain)	**-**	-	**-**	-	**-**	-	**-**	-	**791**	(23)	**2,161**	(19)
Total segmented expenses	**8**	7	**25**	22	**(18)**	(13)	**(45)**	(35)	**2,579**	1,613	**7,712**	4,974
Segmented earnings before the following	**12**	12	**35**	33	**2**	-	**2**	(1)	**1,392**	1,119	**4,201**	3,321
Non-segmented expenses												
Administration									**46**	53	**134**	166
Stock-based compensation (recovery) expense									**(308)**	78	**151**	209
Interest, net									**25**	65	**105**	225
Unrealized risk management (gain) loss									**(2,506)**	76	**(983)**	555
Foreign exchange loss (gain)									**73**	(173)	**156**	(424)
Total non-segmented expenses									**(2,670)**	99	**(437)**	731
Earnings before taxes									**4,062**	1,020	**4,638**	2,590
Taxes other than income tax									**45**	40	**156**	132
Current income tax expense									**171**	105	**477**	257
Future income tax expense									**1,011**	175	**790**	391
Net earnings									**2,835**	700	**3,215**	1,810

Net additions to property, plant and equipment

	Nine Months Ended					
	Sep 30, 2008			Sep 30, 2007		
	Net Expenditures	**Non Cash/Fair Value Changes (1)**	**Capitalized Costs**	Net Expenditures	Non Cash/Fair Value Changes (1)	Capitalized Costs
North America	**$ 1,858**	**$ 18**	**$ 1,876**	$ 1,858	$ 11	$ 1,869
North Sea	**202**	**-**	**202**	395	-	395
Offshore West Africa	**453**	**(3)**	**450**	116	-	116
Other	**1**	**-**	**1**	2	-	2
Horizon Project (2)	**3,068**	**-**	**3,068**	2,469	-	2,469
Midstream	**6**	**-**	**6**	4	-	4
Head office	**13**	**-**	**13**	12	-	12
	$ 5,601	**$ 15**	**$ 5,616**	$ 4,856	$ 11	$ 4,867

(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 2008	Dec 31 2007	**Sep 30 2008**	Dec 31 2007
Segmented assets				
North America	**$ 22,238**	$ 22,033	**$ 23,863**	$ 23,617
North Sea	**1,839**	1,728	**2,044**	1,957
Offshore West Africa	**1,533**	1,188	**1,653**	1,354
Other	**26**	25	**44**	41
Horizon Project	**11,719**	8,651	**11,801**	8,740
Midstream	**205**	205	**356**	333
Head office	**68**	72	**68**	72
	$ 37,628	$ 33,902	**$ 39,829**	$ 36,114

Capitalized interest

The Company capitalizes construction period interest based on Horizon Project costs incurred and the Company's cost of borrowing. Interest capitalization on a particular development phase ceases once construction is substantially complete and this phase of the Horizon Project is available for its intended use. For the nine months ended September 30, 2008, pre-tax interest of $346 million was capitalized to the Horizon Project (September 30, 2007 – $247 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, 2008:	
Interest coverage (times)	
Net earnings [(1)]	7.7x
Cash flow from operations [(2)]	12.5x

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

(2) Cash flow from operations plus current income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

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Printed in Canada