Canadian Natural

News Release

Discipline Opportunity Strategy

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES RECORD PRODUCTION IN THE FIRST SIX MONTHS

CALGARY, ALBERTA – AUGUST 2, 2007 – FOR IMMEDIATE RELEASE

Commenting on second quarter 2007 results, Canadian Natural's Chairman, Allan Markin stated, "As we exit the first half of the year, we continue with our defined plan to manage costs while maximizing value. On the conventional side, the strength of our natural gas program and the quality of our assets was demonstrated through a very productive winter drilling program and successes from a variety of wells that have performed above expectations. Our crude oil program also continues to deliver with solid results in North America. Looking to Horizon, at 75% complete, we remain on track for targeted start-up in the third quarter of 2008 and maintain our focus on execution. "

John Langille, Vice Chairman, stated, "The Company generated a record cash flow of just over $3.1 billion in the first half of 2007. Heavy crude oil differentials widened from Q1/07 but were favorable in Q2/07 considering the significant heavy crude oil conversion capacity shut downs in the US Midwest. The differentials continue to be positively impacted by the pipeline reversals to the Gulf Coast and our marketing of blended products. This reaffirms our belief that our marketing strategy is effective. Our active commodity hedge program underpins our cash flows during the Horizon Project construction period and reduces downside exposure in today's volatile commodity markets."

Steve Laut, President and Chief Operating Officer of Canadian Natural commented "In the first half of 2007 we demonstrated the strength and quality of our asset base as well as our ability to effectively allocate capital to those activities that maximize value. At present, returns and recycle ratios for crude oil are significantly higher than those for natural gas, and therefore crude oil will continue to be the focus of our capital program for the remainder of the year. The high grading of our natural gas inventory has resulted in better than expected natural gas production; however, with minimal scheduled drilling for the remainder of the year, natural gas production will decline somewhat in the second half of 2007. Crude oil production remained strong throughout Q2/07 with volumes expected to grow from Q2/07 to Q3/07 as our thermal projects come off a steaming cycle."

HIGHLIGHTS

($ millions, except as noted)	Three Months Ended Jun 30 2007	Mar 31 2007	Jun 30 2006	Six Months Ended Jun 30 2007	Jun 30 2006
Net earnings	**$ 841**	$ 269	$ 1,038	**$ 1,110**	$ 1,095
per common share, basic and diluted	**$ 1.56**	$ 0.50	$ 1.93	**$ 2.06**	$ 2.04
Adjusted net earnings from operations (1)	**$ 595**	$ 621	$ 514	**$ 1,216**	$ 782
per common share, basic and diluted	**$ 1.10**	$ 1.15	$ 0.96	**$ 2.25**	$ 1.46
Cash flow from operations (2)	**$ 1,513**	$ 1,622	$ 1,287	**$ 3,135**	$ 2,326
per common share, basic and diluted	**$ 2.81**	$ 3.01	$ 2.40	**$ 5.82**	$ 4.33
Capital expenditures, net of dispositions	**$ 1,460**	$ 2,009	$ 1,558	**$ 3,469**	$ 3,867
Daily production, before royalties					
Natural gas (mmcf/d)	**1,722**	1,717	1,475	**1,719**	1,456
Crude oil and NGLs (bbl/d)	**327,494**	327,001	338,852	**327,249**	331,299
Equivalent production (boe/d)	**614,461**	613,114	584,611	**613,790**	573,879

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

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

- Natural gas production volumes remained strong and represented 47% of the Company's total production. Natural gas production for Q2/07 averaged 1,722 mmcf/d, up 17% from 1,475 mmcf/d for Q2/06 and up marginally from 1,717 mmcf/d for Q1/07. Volumes in Q2/07 reflected better than expected production from a number of wells, the addition of Anadarko Canada acquisition volumes, and continued high-grading of opportunities. Stronger production has resulted in Canadian Natural exceeding Q2/07 guidance.
- Annual natural gas production guidance has been increased to reflect the volumes recorded during the first half of 2007.
- Total crude oil and NGLs production for Q2/07 was at the top end of guidance for the quarter at 327,494 bbl/d. Q2/07 production was 3% lower from Q2/06 of 338,852 bbl/d and was comparable to 327,001 bbl/d for Q1/07. Volumes are expected to increase in Q3/07 as a number of thermal wells transition from steam cycles to production cycles.
- Quarterly cash flow was $1.5 billion, a decrease of 7% from Q1/07 and an increase of 18% from Q2/06. The increase from Q2/06 primarily reflects higher after-hedging commodity realizations year over year, whereas the decrease from Q1/07 primarily represents wider heavy crude oil differentials and lower natural gas pricing. Cash flow in Q2/07 was negatively impacted by the strengthening Canadian dollar to US dollar average exchange rate of US$0.9112 compared with US$0.8535 for Q1/07 and US$0.8918 for Q1/06.
- Q2/07 achieved quarterly net earnings of $841 million, a 213% increase from Q1/07 and a 19% decrease from Q2/06. The quarterly adjusted net earnings from operations for Q2/07 were $595 million, a 4% decrease from Q1/07 results and a 16% increase from Q2/06.

- Completed the Q2/07 North American drilling program targeting 78 net crude oil wells and 7 net natural gas wells, excluding stratigraphic test and service wells, with a 95% success ratio. The success rate is a reflection of Canadian Natural's strong, predictable, low-risk asset base. Crude oil drilling activity remained unchanged from Q2/06. Natural gas drilling decreased by 85% compared to Q2/06, reflecting Canadian Natural's reallocation of capital towards a higher return crude oil drilling program.
- Maintained a strong undeveloped conventional core land base in Canada of 12.6 million net acres - a key asset for continued growth.
- Primary heavy crude oil production increased by approximately 3,500 bbl/d in Q2/07 from Q1/07 levels due to stronger production results, recompletions and workovers, and increased drilling activity levels.
- Continued production improvements at the Pelican Lake Field from new drilling activity and the expansion of the enhanced crude oil recovery program. Pelican Lake crude oil production averaged approximately 34,000 bbl/d during the quarter, up 12% or approximately 4,000 bbl/d from Q2/06. Production is targeted to continue to increase throughout the remainder of 2007.
- Secured a deep water drilling rig for the Baobab Field. The equipment will be mobilized in late 2007 or first half 2008, enabling work to begin on the restoration of shut-in production. It is targeted that 3 of the 5 shut-in Baobab wells should come back on stream over the course of 2008.
- The Horizon Oil Sands Project ("Horizon Project") exited Q2/07 75% complete and on track for a targeted Q3/08 start-up.
- Declared a quarterly cash dividend on common shares of C$0.085 per common share, payable July 1, 2007, a 13% increase over the 2006 quarterly dividend.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

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

OPERATIONS REVIEW

Activity by core region

	Net undeveloped land as at Jun 30, 2007 (thousands of net acres)	Drilling activity six months ended Jun 30, 2007 (net wells)
Canadian conventional		
Northeast British Columbia	**2,462**	**50**
Northwest Alberta	**1,523**	**88**
Northern Plains	**6,578**	**347**
Southern Plains	**907**	**28**
Southeast Saskatchewan	**122**	**10**
In-situ Oil Sands	**406**	**155**
	11,998	**678**
Horizon Oil Sands Project	**115**	**98**
United Kingdom North Sea	**298**	**5**
Offshore West Africa	**206**	**2**
	12,617	**783**

Note: Drilling activity includes stratigraphic test and service wells

Drilling activity (number of wells)

	Six Months Ended Jun 30			
	2007		2006	
	Gross	**Net**	Gross	Net
Crude oil	**290**	**271**	196	171
Natural gas	**254**	**207**	616	483
Dry	**74**	**64**	80	68
Subtotal	**618**	**542**	892	722
Stratigraphic test / service wells	**241**	**241**	310	309
Total	**859**	**783**	1,202	1,031
Success rate (excluding stratigraphic test / service wells)		**88%**		91%

North America Conventional

North America natural gas

	Three Months Ended			Six Months Ended	
	Jun 30 2007	Mar 31 2007	Jun 30 2006	**Jun 30 2007**	Jun 30 2006
Natural gas production (mmcf/d)	**1,696**	1,694	1,448	**1,694**	1,430
Net wells targeting natural gas	**7**	245	48	**252**	547
Net successful wells drilled	**6**	201	43	**207**	483
Success rate	**86%**	82%	90%	**82%**	88%

- Q2/07 North America natural gas production increased 17% over Q2/06 and was comparable to Q1/07. The increase reflects completion of a successful winter drilling program and the continued high-grading of assets in conjunction with a focused drilling program. Production will decline somewhat in the second half of the year as a result of the Company's strategic decision to scale back the 2007 drilling program due to reallocation of capital to currently higher return crude oil projects.
- Canadian Natural targeted 7 net natural gas wells in Q2/07 including 2 wells in the Northern Plains region, 4 wells in the Northwest Alberta region and 1 well in the Southern Plains region, with an overall success rate of 86%. This compares to 48 net targeted natural gas wells in Q2/06, an 85% reduction from Q2/06 to Q2/07.
- Planned drilling activity for Q3/07 includes 121 targeted natural gas wells, comparable to the Q3/06 drilling activity of 111 targeted natural gas wells.
- The Company has seen decreased third party service costs along with productivity gains as a result of the industry-wide trend towards scaling back natural gas drilling within the Western Canadian Sedimentary Basin (WCSB).

North America crude oil and NGLs

	Three Months Ended			Six Months Ended	
	Jun 30 2007	Mar 31 2007	Jun 30 2006	**Jun 30 2007**	Jun 30 2006
Crude oil and NGLs production (bbl/d)	**240,420**	237,489	234,780	**238,962**	228,901
Net wells targeting crude oil	**78**	207	78	**285**	168
Net successful wells drilled	**75**	191	76	**266**	164
Success rate	**96%**	92%	97%	**93%**	98%

- Q2/07 North America crude oil and NGLs production increased 1% from Q1/07 and increased 2% over Q2/06 levels. Conventional heavy crude oil and Pelican Lake crude oil experienced solid performance and production growth that offset the slight decrease in thermal volumes for Q2/07, which was largely a result of the timing of the normal steaming cycle.
- During Q2/07, drilling activity included 22 net wells targeting heavy crude oil, 40 net wells targeting Pelican Lake crude oil, 14 net wells targeting thermal crude oil and 2 net wells targeting light crude oil.

- The Primrose East Expansion, a new facility located 15 kilometres from the existing Primrose South steam plant and 25 kilometres from the Wolf Lake central processing facility, is anticipated to add approximately 40,000 bbl/d. The Primrose East Expansion received Board of Directors' sanction in 2006 and The Alberta Energy and Utilities Board regulatory approval in the first quarter of 2007. Drilling and construction are currently underway, and production is targeted to commence in 2009. Primrose East is the second phase of the 300,000 bbl/d conventional expansion plan identified to unlock the value from Canadian Natural's thermal crude oil resource base.
- In early 2007, Canadian Natural issued its proposed third phase of the conventional expansion plan with a development plan for the 30,000 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 is targeting to file its formal regulatory application documents for this project in the latter half of 2007. Final corporate sanction may depend upon the results of potential changes to royalty regimes and environmental regulations, and their associated costs.
- Development of new pads and secondary recovery conversion projects at Pelican Lake continued as expected throughout the Q2/07. Drilling consisted of 40 horizontal wells, with plans to drill 52 additional horizontal wells for the remainder of 2007. The response from the water and polymer flood project continues to be positive. Pelican Lake production averaged approximately 34,000 bbl/d for Q2/07 compared to approximately 30,000 bbl/d for Q2/06.
- Conventional heavy crude oil production volumes increased by approximately 3,500 bbl/d in Q2/07 from Q1/07 due to increased drilling activity levels, recompletions and workovers that commenced during the second half of 2006 as a result of the narrowing heavy crude oil differential.
- Planned drilling activity for Q3/07 includes 147 net crude oil wells, excluding stratigraphic test and service wells.

Potential Changes to Legislation

- The Alberta provincial government is currently reviewing its crude oil and natural gas royalty regime. The results of this review, which are not determinable at this date, are expected in the fall of 2007 and may place additional costs on the crude oil and natural gas industry.
- The crude oil and natural gas industry is also experiencing cost pressures related to changes to environmental regulations, both in North America and internationally. In Canada, the Federal government is drafting policy and legislation to control greenhouse gas emissions. In Alberta, provincial regulations came into effect July 1, 2007, while in the UK, greenhouse gas regulations have been in effect since 2005. The Company has processes in place to comply with the regulations. Additional requirements resulting from greenhouse gas legislation will add to the cost of executing projects company wide.

International

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

	Three Months Ended			Six Months Ended	
	Jun 30 2007	Mar 31 2007	Jun 30 2006	**Jun 30 2007**	Jun 30 2006
Crude oil production (bbl/d)					
North Sea	**57,286**	61,869	63,703	**59,565**	62,261
Offshore West Africa	**29,788**	27,643	40,369	**28,722**	40,137
Natural gas production (mmcf/d)					
North Sea	**15**	15	17	**15**	17
Offshore West Africa	**11**	8	10	**10**	9
Net wells targeting crude oil	**3.1**	2.0	2.8	**5.1**	7.0
Net successful wells drilled	**3.1**	2.0	2.8	**5.1**	7.0
Success rate	**100%**	100%	100%	**100%**	100%

North Sea

- Canadian Natural continues to execute its exploitation strategy in the North Sea. The first ongoing stage of this exploitation program is based upon optimizing existing facilities and waterfloods. The second stage of exploitation incorporates more near pool development and exploration in order to maximize utilization of the common facilities and ultimately extend all fields' economic lives. Ongoing development at Ninian, the Columba Terraces and the Lyell Field continued in Q2/07.
- In Q2/07, 1.9 net crude oil wells were drilled along with 1.8 net water injectors, with an additional 1.9 net wells drilling at the end of the quarter.
- The development of the Lyell Field continued with the first well onstream in Q2 through the existing infrastructure. A second well is scheduled for completion in early Q3/07. Tranche 1 of the development comprises two production wells in 2007, and an additional one production well and one well workover in 2008.
- Construction of the Columba E raw water injection facilities continued during the quarter. During Q2/07, commissioning of the facilities was completed and 2 water injection wells were delivered, allowing water injection into the reservoir to commence.
- Completed the successful Ninian Central platform turnaround in Q2/07. Planned platform shutdowns are scheduled for Q3/07 at Ninian, B-Block and T-Block, which will impact production in the third quarter.

Offshore West Africa

- During Q2/07, 1.2 net wells were drilled with 0.6 additional net wells drilling at the end of the quarter.
- First crude oil from West Espoir commenced production in mid 2006 with 3 production wells and 2 injector wells, followed by an additional production well in Q1/07. During Q2/07, 2 additional production wells were added. The West Espoir area has seen favorable production growth and development drilling is continuing until 2008 with producers and injectors being brought on-line as they are completed.
- A deep water drilling rig has been secured for the Baobab Field. The rig will be mobilized in late 2007 or first half 2008 with the Company targeting to bring 3 of 5 of the shut-in Baobab wells back into production over the course of 2008.
- At the 90% owned and operated Olowi Field in offshore Gabon, all major construction contracts have been awarded. The project is on schedule with drilling scheduled to commence in Q2/08 and first crude oil is targeted for late 2008. Production is targeted to plateau at approximately 20,000 bbl/d.

Horizon Project

- Canadian Natural achieved a major milestone on the Horizon Project during Q2/07, with overall work progress at the end of the quarter reaching 75% complete and field construction approaching two thirds complete. All major vessels have either been erected or are currently on site. Work scheduled for the coming months will focus on mechanical construction, which is scheduled to be completed through a combination of lump sum and reimbursable contracts.
- The Horizon Project remains on track for targeted start-up in the third quarter of 2008. Project progress slowed slightly during the quarter due in part to labour productivity, the temporary work shut down on the tank farm and delays associated with a realignment of certain contract packages to match scope to the marketplace contractor supply to better manage costs.
- Despite the challenges of a construction market in Alberta operating at high capacity, the Company has been able to build the on-site manpower to over 7,000 personnel. With the success of the Fly-In Fly-Out program and Managed Open Site policy Canadian Natural has been able to add workers as required.
- Management of costs continues to be a focus for the team and the Horizon Project currently remains within the Company's forecast estimate of 5% to 12% above the original $6.8 billion Board Authorization for construction capital spending.
- The quarterly update for Phase 1 of the Horizon Project is as follows:

Project status summary	**Jun 30, 2007**		Sep 30, 2007
	Actual	Plan	Plan
Phase 1 - Work progress (cumulative)	75%	77%	88%
Phase 1 - Construction capital spending (cumulative)*	79%	77%	85%

** Relates to overall Phase 1 construction capital of $6.8 billion.*

Accomplished during Q2/07

Detailed Engineering

- Overall detailed engineering 97% complete and substantially complete in most areas.

Procurement

- Overall procurement progress is 95% complete.
- Have awarded over $5.4 billion in purchase orders and contracts to date.
- Delivered to site over 30,000 standard loads.
- Operations and maintenance service and supply agreements are in negotiation.

Modularization

- Delivered an additional 172 oversized loads to site during the quarter for a total of 1,424 loads, which represents approximately 86% of the total requirement.

Construction

- Overall construction progress is 63% complete.
- Mine overburden removal has moved over 37 million bank cubic meters, which represents approximately 54% of the total to be moved and is 1% ahead of schedule.
- Construction of cofferdam for the Tar River Diversion completed in Mining.
- Fabrication of Crushing Plants, Surge Facility and Conveyor Structure is 100% complete in the Ore Preparation Plant.
- Started erection of Conveyors in Ore Preparation.
- Completed Hot Water Tank in Extraction.
- Hydro-tested Primary Separation Cells and Hot Water Tank.

- Completed construction and hydro-testing of Inclined Plate Settlers in Froth Treatment.
- Flare Stacks installed in Upgrading.
- Mechanically completed cooling tower piping.
- Mechanically completed Inhibited Water and Cooling Water Pumphouse buildings.
- 42" Water Pipeline completed.
- Wet Gas Compressor received and installed.
- Completed installation of Coker and Diluent Recovery Unit process structures.
- Completed interconnecting welding of Primary Upgrading's piperacks.
- Energize main electrical substations R1/R2.

Milestones for the Third Quarter of 2007

- Complete construction of Raw Water Pond.
- Extraction plant hydro-testing.
- Start of pre-commissioning activities in all Bitumen Production Areas.
- Permanent Power energized in R1/R2 corridors pump houses.
- Electrically energize Main Electrical Substation.
- Start commissioning of Recycle Water Pond.

Operations Readiness

- Canadian Natural is also well into the planning for commissioning and start-up. The commissioning plans are established to identify the priority systems that will be required later this year and early in 2008. The Company is currently hiring and training operating personnel, setting up procedures and systems and continues to develop the start-up strategies to ensure the Horizon Project stays on track for first crude oil.

MARKETING	Three Months Ended			Six Months Ended	
	Jun 30 2007	Mar 31 2007	Jun 30 2006	**Jun 30 2007**	Jun 30 2006
Crude oil and NGLs pricing					
WTI[1] benchmark price (US$/bbl)	**$ 65.02**	$ 58.23	$ 70.70	**$ 61.64**	$ 67.14
Lloyd Blend Heavy oil differential from WTI (%)	**30%**	27%	25%	**29%**	35%
Corporate average pricing before risk management (C$/bbl)	**$ 53.74**	$ 51.71	$ 60.05	**$ 52.72**	$ 52.22
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 6.99**	$ 7.07	$ 5.95	**$ 7.03**	$ 7.37
Corporate average pricing before risk management (C$/mcf)	**$ 7.44**	$ 7.74	$ 6.16	**$ 7.59**	$ 7.21

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

- In Q2/07, the Company experienced a widening of the Lloyd Blend heavy crude oil differential of WTI to 30% due to refinery conversion capacity outages, which for Q2/07 represented approximately 150,000 bbl/d of heavy crude oil refining capacity shut downs in PADD II. Given the level of reduced conversion capacity the Company believes a 30% differential of WTI to be favorable, considering past history for similar outages.

- Canadian Natural has committed to 25,000 bbl/d of pipeline capacity on the Pegasus Pipeline which transports Company crude oil volumes to the U.S. Gulf Coast as part of the Company's efforts towards working with various industry groups to find new markets for Western Canadian heavy crude oil and to ease the logistical constraints in getting crude oil to the area. The pipeline reversal has had the impact of improving the corporate realized price on Canadian Natural's heavy crude oil production. The heavy crude oil sold to the Gulf Coast receives Mayan equivalent pricing, which receives a premium to the Lloyd Blend price. For Q2/07, the Mayan differential to WTI averaged $12.45/bbl or 19%.
- During Q2/07, the Company contributed approximately 134,000 bbl/d of its heavy crude oil streams to the Western Canadian Select blend as market conditions resulted in this strategy offering the optimal pricing for bitumen.
- Fluctuations in North American natural gas prices from comparable periods in 2006 related to weather and storage levels.

FINANCIAL REVIEW

- Canadian Natural has structured its financial position to profitably grow its conventional crude oil and natural gas operations over the next several years and to build the financial capacity to complete the Horizon Project and other major projects. A brief summary of its strengths are:
  - A diverse asset base geographically and by product - produced in excess of 614,400 boe/d in Q2/07, comprised of approximately 47% natural gas and 53% crude oil - with 95% of production located in G7 countries with stable and secure economies.
  - Financial stability and liquidity – first half cash flow of $3.1 billion, available unused bank lines of $1.4 billion at June 30, 2007 and access to capital debt markets supported by strong credit ratings.
  - Reduced volatility of commodity prices – a proactive commodity hedging program to reduce the downside risk of volatility in commodity prices supporting cash flow for its capital expenditure program throughout the Horizon Project.
- Declared a quarterly cash dividend on common shares of C$0.085 per common share, payable July 1, 2007, a 13% increase over the 2006 quarterly dividend.

OUTLOOK

The Company forecasts 2007 production levels before royalties to average between 1,649 and 1,688 mmcf/d of natural gas and between 322,000 and 348,000 bbl/d of crude oil and NGLs. Q3/07 production guidance before royalties is forecast to average between 1,632 and 1,669 mmcf/d of natural gas and between 331,000 and 349,000 bbl/d of crude oil and NGLs. Detailed guidance on revised production levels, capital allocation and operating costs can be found on the Company's website at http://www.cnrl.com/investor_info/corporate_guidance/.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Forward-Looking Statements

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

The forward-looking statements are based on current expectations and are subject to known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements of the Company, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; foreign currency exchange rates; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition, availability and cost of seismic, drilling and other equipment; ability of the Company to complete its capital programs; ability of the Company to transport its products to market; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas; availability and cost of financing; success of exploration and development activities; timing and success of integrating the business and operations of acquired companies; production levels; uncertainty of reserve estimates; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations); asset retirement obligations; and other circumstances affecting revenues and expenses. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

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

Statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future.

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

Management’s Discussion and Analysis

Management’s Discussion and Analysis of the financial condition and results of operations of the Company should be read in conjunction with the unaudited interim consolidated financial statements for the six months ended June 30, 2007 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2006.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles (“GAAP”). This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations and cash flow from operations. These financial measures are not defined by GAAP and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with GAAP, as an indication of the Company's performance. The measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings in the “Financial Highlights” section.

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

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

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

The following discussion refers primarily to the Company’s financial results for the six and three months ended June 30, 2007 in relation to the comparable periods in 2006 and the first quarter of 2007. The accompanying tables form an integral part of this MD&A. This MD&A is dated July 31, 2007. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2006, is available on SEDAR at www.sedar.com.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Six Months Ended	
	Jun 30 2007	Mar 31 2007	Jun 30 2006 (1)	**Jun 30 2007**	Jun 30 2006 (1)
Revenue, before royalties	**$ 3,152**	$ 3,118	$ 3,041	**$ 6,270**	$ 5,709
Net earnings	**$ 841**	$ 269	$ 1,038	**$ 1,110**	$ 1,095
Per common share – basic and diluted	**$ 1.56**	$ 0.50	$ 1.93	**$ 2.06**	$ 2.04
Adjusted net earnings from operations (2)	**$ 595**	$ 621	$ 514	**$ 1,216**	$ 782
Per common share – basic and diluted	**$ 1.10**	$ 1.15	$ 0.96	**$ 2.25**	$ 1.46
Cash flow from operations (3)	**$ 1,513**	$ 1,622	$ 1,287	**$ 3,135**	$ 2,326
Per common share – basic and diluted	**$ 2.81**	$ 3.01	$ 2.40	**$ 5.82**	$ 4.33
Capital expenditures, net of dispositions	**$ 1,460**	$ 2,009	$ 1,558	**$ 3,469**	$ 3,867

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

(2) Adjusted net earnings from operations is a non-GAAP term 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 following reconciliation lists the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.

	Three Months Ended			*Six Months Ended*	
($ millions)	***Jun 30 2007***	*Mar 31 2007*	*Jun 30 2006*	***Jun 30 2007***	*Jun 30 2006*
Net earnings as reported	***$ 841***	*$ 269*	*$ 1,038*	***$ 1,110***	*$ 1,095*
Stock-based compensation expense (recovery), net of tax[(a)]	***74***	*17*	*(21)*	***91***	*67*
Unrealized risk management (gain) loss, net of tax[(b)]	***(35)***	*362*	*(17)*	***327***	*(12)*
Unrealized foreign exchange gain, net of tax[(c)]	***(214)***	*(27)*	*(48)*	***(241)***	*(40)*
Effect of statutory tax rate changes on future income tax liabilities[(d)]	***(71)***	*-*	*(438)*	***(71)***	*(328)*
Adjusted net earnings from operations	***$ 595***	*$ 621*	*$ 514*	***$ 1,216***	*$ 782*

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

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

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

(d) All substantively enacted adjustments in applicable income tax rates are applied to underlying assets and liabilities on the Company's balance sheet in determining future income tax assets and liabilities. The impact of these tax rate changes is recorded in net earnings during the period the legislation is substantively enacted. Income tax rate changes in the second quarter of 2007 resulted in a reduction of future income tax liabilities of approximately $71 million in North America. Income tax rate changes in the first quarter of 2006 resulted in an increase of future income tax liabilities of approximately $110 million in the UK North Sea. Income tax rate changes in the second quarter of 2006 resulted in a reduction of future income tax liabilities of approximately $438 million in North America.

(3) *Cash flow from operations is a non-GAAP term that represents net earnings adjusted for non-cash items. The Company evaluates its performance based on cash flow from operations. The Company considers cash flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. Cash flow from operations may not be comparable to similar measures presented by other companies.*

	Three Months Ended			Six Months Ended	
($ millions)	***Jun 30 2007***	*Mar 31 2007*	*Jun 30 2006*	***Jun 30 2007***	*Jun 30 2006*
Net earnings	***$ 841***	*$ 269*	*$ 1,038*	***$ 1,110***	*$ 1,095*
Non-cash items:					
Depletion, depreciation and amortization	***720***	*709*	*557*	***1,429***	*1,078*
Asset retirement obligation accretion	***17***	*18*	*16*	***35***	*33*
Stock-based compensation expense	***106***	*25*	*(34)*	***131***	*98*
Unrealized risk management (gain) loss	***(57)***	*536*	*(26)*	***479***	*(18)*
Unrealized foreign exchange (gain) loss	***(250)***	*(32)*	*(58)*	***(282)***	*(48)*
Deferred petroleum revenue tax (recovery) expense	***20***	*(3)*	*18*	***17***	*44*
Future income tax expense (recovery)	***116***	*100*	*(224)*	***216***	*44*
Cash flow from operations	***$ 1,513***	*$ 1,622*	*$ 1,287*	***$ 3,135***	*$ 2,326*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

For the six months ended June 30, 2007, the Company reported net earnings of $1,110 million compared to net earnings of $1,095 million for the six months ended June 30, 2006. Net earnings for the six months ended June 30, 2007 included unrealized after-tax expenses of $106 million related to the effects of risk management activities, fluctuations in foreign exchange rates, stock-based compensation expense and the impact of statutory tax rate changes on future income tax liabilities, compared to net after-tax income of $313 million for the six months ended June 30, 2006. Excluding these items, adjusted net earnings from operations for the six months ended June 30, 2007 increased to $1,216 million from $782 million for the six months ended June 30, 2006. The increase from the comparable period in 2006 was primarily due to increased sales volumes and decreased realized risk management losses. These factors were partially offset by increased production expense and increased depletion, depreciation and amortization expense.

Net earnings in the second quarter of 2007 were $841 million compared to net earnings of $1,038 million in the second quarter of 2006 and net earnings of $269 million in the prior quarter. Net earnings in the second quarter of 2007 included unrealized after-tax income of $246 million related to the effects of risk management activities, fluctuations in foreign exchange rates, stock-based compensation expense and the impact of statutory tax rate changes on future income tax liabilities, compared to net after-tax income of $524 million for the second quarter of 2006 and net after-tax expenses of $352 million in the prior quarter. Excluding these items, adjusted net earnings from operations in the second quarter of 2007 increased to $595 million from $514 million in the second quarter of 2006, and decreased from $621 million in the prior quarter. The increase in adjusted net earnings from the second quarter of 2006 was primarily due to the impact of increased natural gas pricing, increased sales volumes, and decreased realized risk management losses. These factors were partially offset by the impact of a stronger Canadian dollar relative to the US dollar, decreased crude oil pricing related to lower WTI benchmark pricing and a wider Heavy Crude Oil Differential from WTI ("Heavy Differential"), increased production expense and increased depletion, depreciation and amortization expense. The decrease from the prior quarter was primarily due to decreased natural gas pricing, increased realized risk management losses on crude oil, and the impact of a stronger Canadian dollar relative to the US dollar, partially offset by increased crude oil pricing.

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

The Company's commodity hedging program reduces the risk of volatility in commodity price markets and supports the Company's cash flow for its capital expenditure program throughout the Horizon Oil Sands Project ("Horizon Project") construction period. This program allows for the hedging of up to 75% of the near 12 months budgeted production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. In accordance with the policy, approximately 60% of expected crude oil volumes and approximately 70% of expected natural gas volumes are hedged for the remainder of 2007. In addition, 77,000 bbl/d of crude oil volumes are protected by WTI put options for the remainder of 2007 at a strike price of US$60.00 per barrel.

The Company has hedged 220,000 bbl/d of crude oil volumes for the year 2008. Of the 220,000 bbl/d, 20,000 bbl/d are hedged by Mayan price collars with a US$50.00 floor, 150,000 bbl/d are hedged by WTI price collars with a US$60.00 floor and 50,000 bbl/d are hedged by WTI put options with a US$55.00 strike price. The Company has also entered into an additional 50,000 bbl/d of WTI price collars with a US$60.00 floor for the first quarter of 2008. In addition, 900,000 GJ/d of natural gas volumes are hedged by AECO price collars for the first quarter of 2008; 400,000 GJ/d with a $7.00 floor and 500,000 GJ/d with a $7.50 floor.

As disclosed in note 2 to the Company's unaudited interim consolidated financial statements, commencing January 1, 2007 all derivative financial instruments are recognized at fair value on the consolidated balance sheet at each balance sheet date. As effective as the Company's hedges are against reference commodity prices, a substantial portion of the derivative financial instruments entered into by the Company do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The change in the fair value of the non-designated hedges is based on prevailing forward commodity prices in effect at the end of each reporting period and is reflected in risk management activities in consolidated net earnings. The cash settlement amount of the risk management derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the derivative financial instruments, as compared to their mark-to-market value at June 30, 2007.

Due to the changes in crude oil and natural gas forward pricing and the reversal of prior-period unrealized gains and losses, the Company recorded a net unrealized loss of $479 million ($327 million after-tax) on its commodity risk management activities for the six months ended June 30, 2007, including a $57 million ($35 million after-tax) unrealized gain for the three months ended June 30, 2007. Mark-to-market unrealized gains and losses do not impact the Company's current cash flow or its ability to finance ongoing capital programs. The Company continues to believe that its risk management program meets its objective of securing funding for its capital projects and does not intend to alter its current strategy of obtaining price certainty for its crude oil and natural gas sales. For further details, refer to Risk Management Activities on page 31 of this MD&A.

The Company also recorded a $131 million ($91 million after-tax) stock-based compensation expense as a result of the 14% increase in the Company's share price in the six months ended June 30, 2007, and a $106 million ($74 million after-tax) stock-based compensation expense as a result of the 11% increase in the Company's share price for the three months ended June 30, 2007 (Company's share price as at: June 30, 2007 – C$70.78; March 31, 2007 – C$63.75; December 31, 2006 – C$62.15; June 30, 2006 – C$61.72). As required by GAAP, the Company records a liability for potential cash payments to settle its outstanding employee stock options each reporting period based on the difference between the exercise price of the stock options and the market price of the Company's common shares, pursuant to a graded vesting schedule. The liability is revalued each quarter to reflect the changes in the market price of the Company's common shares and the options exercised or surrendered in the period, with the net change recognized in net earnings, or capitalized as part of the Horizon Project during the construction period. The stock-based compensation liability at June 30, 2007 reflected the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on June 30, 2007. In periods when substantial share price changes occur, the Company's net earnings are subject to significant volatility. The Company utilizes its stock-based compensation plan to attract and retain employees in a competitive environment. All employees participate in this plan.

Cash flow from operations for the six months ended June 30, 2007 increased to a record $3,135 million from $2,326 million for the six months ended June 30, 2006. The increase from the comparable period in 2006 was primarily due to increased sales volumes and decreased realized risk management losses, offset by increased production expense.

Cash flow from operations for the second quarter of 2007 increased to $1,513 million from $1,287 million for the second quarter of 2006, and decreased from $1,622 million in the prior quarter. The increase from the second quarter of 2006 was primarily due to the impact of increased natural gas pricing, increased sales volumes, and decreased realized risk management losses. These factors were partially offset by the impact of a stronger Canadian dollar relative to the US dollar, decreased crude oil WTI benchmark pricing and a wider Heavy Differential, and increased production expense. The decrease from the prior quarter was primarily due to decreased natural gas pricing, increased realized risk management losses on crude oil, and the impact of a stronger Canadian dollar relative to the US dollar, partially offset by increased crude oil pricing.

Total production before royalties increased 7% to average 613,790 boe/d for the six months ended June 30, 2007 from 573,879 boe/d for the six months ended June 30, 2006. Production for the second quarter of 2007 increased 5% to 614,461 boe/d from 584,611 boe/d in the second quarter of 2006 and was comparable to 613,114 boe/d for the prior quarter.

SUMMARY OF QUARTERLY RESULTS

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

($ millions, except per common share amounts)		**Jun 30 2007**		Mar 31 2007		Dec 31 2006		Sep 30 2006
Revenue, before royalties [1]	**$**	**3,152**	$	3,118	$	2,826	$	3,108
Net earnings	**$**	**841**	$	269	$	313	$	1,116
Net earnings per common share								
– Basic and diluted	**$**	**1.56**	$	0.50	$	0.58	$	2.08

($ millions, except per common share amounts)		Jun 30 2006		Mar 31 2006		Dec 31 2005		Sep 30 2005
Revenue, before royalties [1]	$	3,041	$	2,668	$	3,319	$	3,163
Net earnings	$	1,038	$	57	$	1,104	$	151
Net earnings per common share								
– Basic and diluted	$	1.93	$	0.11	$	2.06	$	0.28

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

Net earnings over the eight most recently completed quarters generally reflected fluctuations in realized crude oil and natural gas prices, increased sales volumes, the impact of mark-to-market accounting treatment of financial instruments and adjustments to future income tax liabilities due to jurisdictional tax rate changes. More specifically, volatility in quarterly net earnings was primarily due to:

- Crude oil pricing. Crude oil prices reflected demand growth, continued geopolitical uncertainties and fluctuations in the Heavy Differential in North America. Hurricane activity in the Gulf of Mexico in the third quarter of 2005 further contributed to increased world benchmark crude oil prices.
- Natural gas pricing. Natural gas prices primarily reflected fluctuations in demand for natural gas and in inventory storage levels as a result of milder temperatures experienced during 2007 and 2006 and hurricane activity in the third quarter of 2005.
- Crude oil and NGLs sales volumes. Crude oil and NGLs sales volumes primarily reflected increased production from the Company's Primrose thermal projects, the positive results from the Pelican Lake water and polymer flood projects, additional production volumes from the Anadarko Canada Corporation ("ACC") acquisition completed in the fourth quarter of 2006, development of West and East Espoir, and production from the Baobab Field located offshore Côte d'Ivoire, which commenced in the third quarter of 2005.
- Natural gas sales volumes. Natural gas sales volumes reflected additional natural gas production from the ACC acquisition and internally generated growth. The increase was partially offset by the production decrease due to the Company's strategic reduction in natural gas drilling activity made in response to low natural gas prices in 2006 and inflationary cost pressures.
- The value of the Canadian dollar relative to the US dollar. A fluctuating Canadian dollar relative to the US dollar impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominately on US dollar denominated benchmarks.
- Realized and unrealized gains and losses from the mark-to-market treatment of the Company's commodity and cross currency hedges.
- Jurisdictional tax rate changes substantively enacted in the various periods.

- Unrealized foreign exchange gains and losses due to the fluctuation of the Canadian dollar in relation to the US dollar with respect to the US dollar debt balances, UK pounds sterling denominated working capital balances, as well as the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling.
- Unrealized expenses and recoveries due to the mark-to-market treatment of the Company's stock-based compensation liability. The liability reflected a general increase in the Company's share price over the eight most recently completed quarters.
- Increased production expense primarily due to industry-wide inflationary cost pressures.
- Increased depletion, depreciation and amortization expense primarily associated with the ACC acquisition, increased finding and development costs associated with crude oil and natural gas exploration and increased estimated future costs to develop the Company's proved undeveloped reserves.

OPERATING HIGHLIGHTS

	Three Months Ended			Six Months Ended	
	Jun 30 2007	Mar 31 2007	Jun 30 2006	**Jun 30 2007**	Jun 30 2006
Crude oil and NGLs ($/bbl) [1]					
Sales price [2]	$ **53.74**	$ 51.71	$ 60.05	$ **52.72**	$ 52.22
Royalties	**5.46**	4.92	5.14	**5.19**	4.34
Production expense	**15.01**	13.81	11.92	**14.40**	11.63
Netback	$ **33.27**	$ 32.98	$ 42.99	$ **33.13**	$ 36.25
Natural gas ($/mcf) [1]					
Sales price [2]	$ **7.44**	$ 7.74	$ 6.16	$ **7.59**	$ 7.21
Royalties	**1.10**	1.48	1.11	**1.29**	1.40
Production expense	**0.89**	0.97	0.80	**0.93**	0.80
Netback	$ **5.45**	$ 5.29	$ 4.25	$ **5.37**	$ 5.01
Barrels of oil equivalent ($/boe) [1]					
Sales price [2]	$ **49.70**	$ 49.32	$ 50.36	$ **49.50**	$ 48.39
Royalties	**5.99**	6.76	5.80	**6.37**	6.11
Production expense	**10.44**	10.10	8.85	**10.27**	8.66
Netback	$ **33.27**	$ 32.46	$ 35.71	$ **32.86**	$ 33.62

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

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

BUSINESS ENVIRONMENT

	Three Months Ended			Six Months Ended	
	Jun 30 2007	Mar 31 2007	Jun 30 2006	**Jun 30 2007**	Jun 30 2006
WTI benchmark price (US$/bbl)	**$ 65.02**	$ 58.23	$ 70.70	**$ 61.64**	$ 67.14
Dated Brent benchmark price (US$/bbl)	**$ 68.74**	$ 57.76	$ 69.63	**$ 63.28**	$ 65.74
Differential to LLB blend (US$/bbl)	**$ 19.42**	$ 15.80	$ 17.79	**$ 17.62**	$ 23.21
LLB blend differential from WTI (%)	**30%**	27%	25%	**29%**	35%
Condensate benchmark price (US$/bbl)	**$ 65.66**	$ 58.78	$ 71.51	**$ 62.28**	$ 67.59
NYMEX benchmark price (US$/mmbtu)	**$ 7.56**	$ 6.96	$ 6.83	**$ 7.26**	$ 7.96
AECO benchmark price (C$/GJ)	**$ 6.99**	$ 7.07	$ 5.95	**$ 7.03**	$ 7.37
US / Cdn dollar average exchange rate (US$)	**$ 0.9112**	$ 0.8535	$ 0.8918	**$ 0.8812**	$ 0.8786

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$61.64 per bbl for the six months ended June 30, 2007, a decrease of 8% from US$67.14 per bbl for the six months ended June 30, 2006. In the second quarter of 2007, WTI averaged US$65.02 per bbl, a decrease of 8% from US$70.70 per bbl in the second quarter of 2006, and an increase of 12% from US$58.23 per bbl in the prior quarter. Fluctuations in WTI pricing in the second quarter were mainly due to continued geopolitical events causing increased market uncertainty, as well as a series of US refinery outages resulting in logistical constraints and inventory build up, particularly at Cushing, Oklahoma.

Crude oil sales contracts for the Company's North Sea and Offshore West Africa segments are typically based on Brent pricing, which continued to benefit from strong European and Asian demand in the second quarter of 2007. Dated Brent ("Brent") averaged US$63.28 per bbl for the six months ended June 30, 2007, a decrease of 4% compared to US$65.74 per bbl for the six months ended June 30, 2006. In the second quarter of 2007, Brent averaged US$68.74 per bbl, a decrease of 1% compared to US$69.63 per bbl for the second quarter of 2006, and an increase of 19% from US$57.76 per bbl for the prior quarter. The widening differential between Brent and WTI was due to strong European and Asian market demands and logistical constraints at Cushing, Oklahoma, impacting inventory levels and WTI pricing.

Company-wide, realized crude oil prices for the six months ended June 30, 2007 increased slightly as a result of the narrower Heavy Differential in North America, partially offset by lower benchmark WTI and Brent pricing. Heavy Differentials averaged 29% for the six months ended June 30, 2007 compared to 35% for the six months ended June 30, 2006. For the second quarter of 2007, Heavy Differentials averaged 30% compared to 25% for the second quarter of 2006, and 27% for the prior quarter. The widening of the Heavy Differentials from the comparable periods was primarily due to reduced US refinery utilization. Second quarter 2007 realized prices were also impacted by the stronger Canadian dollar, which decreased the Canadian dollar sales price the Company received for its crude oil sales, based on US dollar denominated benchmarks.

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

NYMEX natural gas prices averaged US$7.26 per mmbtu for the six months ended June 30, 2007, a decrease of 9% from US$7.96 per mmbtu for the six months ended June 30, 2006. In the second quarter of 2007, the NYMEX natural gas price averaged US$7.56 per mmbtu, an increase of 11% from US$6.83 per mmbtu for the second quarter of 2006, and an increase of 9% from US$6.96 per mmbtu for the prior quarter. AECO natural gas prices decreased 5% to average $7.03 per GJ for the six months ended June 30, 2007, compared to $7.37 per GJ for the six months ended June 30, 2006. In the second quarter of 2007 AECO natural gas prices averaged $6.99 per GJ, an increase of 17% from $5.95 per GJ in the second quarter of 2006, and comparable to $7.07 per GJ for the prior quarter. Fluctuations in natural gas prices from the comparable periods in 2006 were primarily related to weather and storage levels. Natural gas inventory levels in North America continued to remain high in the second quarter of 2007, notwithstanding production declines in Canada due to reduced drilling activity, due to the significant increase in liquefied natural gas imports and stable production levels in the US.

Operating, Royalty and Capital Costs

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

The crude oil and natural gas industry is also experiencing cost pressures related to environmental regulations, both in North America and internationally. In Canada, the Federal government is drafting policy and legislation to control greenhouse gas emissions. In Alberta, provincial regulations came into effect July 1, 2007, while in the UK greenhouse gas regulations have been in effect since 2005. The Company has processes in place to comply with the regulations. Additional requirements of greenhouse gas legislation will add to the cost of executing projects company wide.

The Alberta provincial government is currently reviewing the oil and gas royalty regime, which may result in changes to the Company's royalty obligations in future years.

The increased cost pressures, the impact of environmental regulations, and the outcome of the royalty review may adversely impact the Company's future net earnings, cash flow and capital projects.

PRODUCT PRICES (1)

	Three Months Ended			Six Months Ended	
	Jun 30 2007	Mar 31 2007	Jun 30 2006	**Jun 30 2007**	Jun 30 2006
Crude oil and NGLs ($/bbl) (2)					
North America	**$ 47.20**	$ 46.09	$ 54.94	**$ 46.66**	$ 45.04
North Sea	**$ 73.18**	$ 68.83	$ 73.19	**$ 70.84**	$ 70.68
Offshore West Africa	**$ 72.84**	$ 58.60	$ 72.97	**$ 65.34**	$ 69.10
Company average	**$ 53.74**	$ 51.71	$ 60.05	**$ 52.72**	$ 52.22
Natural gas ($/mcf) (2)					
North America	**$ 7.47**	$ 7.79	$ 6.21	**$ 7.62**	$ 7.28
North Sea	**$ 3.92**	$ 4.49	$ 2.33	**$ 4.21**	$ 2.36
Offshore West Africa	**$ 6.22**	$ 5.97	$ 5.30	**$ 6.11**	$ 5.43
Company average	**$ 7.44**	$ 7.74	$ 6.16	**$ 7.59**	$ 7.21
Company average ($/boe)(2)	**$ 49.70**	$ 49.32	$ 50.36	**$ 49.50**	$ 48.39
Percentage of revenue (excluding midstream revenue)					
Crude oil and NGLs	**57%**	56%	68%	**57%**	54%
Natural gas	**43%**	44%	32%	**43%**	46%

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

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

The Company's realized crude oil prices increased slightly to average $52.72 per bbl for the six months ended June 30, 2007 from $52.22 per bbl for the six months ended June 30, 2006. Realized crude oil prices for the second quarter of 2007 decreased 11% to average $53.74 per bbl from $60.05 per bbl for the second quarter of 2006, and increased 4% from $51.71 per bbl for the prior quarter. The Company's realized crude oil prices increased slightly from the six months ended June 30, 2006 primarily as a result of a narrower Heavy Differential, partially offset by decreased WTI and Brent benchmark pricing.

The Company's realized natural gas price increased 5% to average $7.59 per mcf for the six months ended June 30, 2007 from $7.21 per mcf for the six months ended June 30, 2006. In the second quarter of 2007, the Company's realized natural gas price increased 21% to average $7.44 per mcf from $6.16 per mcf in the second quarter of 2006, and decreased 4% from $7.74 per mcf for the prior quarter. Fluctuations in natural gas prices from the comparable periods in 2006 were primarily related to weather and storage levels. The decrease in realized natural gas prices from the prior quarter primarily reflected normal seasonality and milder temperatures during 2007, partially offset by the impact of an overall reduction in natural gas drilling activity in Canada in response to industry wide inflationary pressures.

North America

North America realized crude oil prices increased 4% to average $46.66 per bbl for the six months ended June 30, 2007 from $45.04 per bbl for the six months ended June 30, 2006. Realized crude oil prices in the second quarter of 2007 averaged $47.20 per bbl, a 14% decrease from $54.94 per bbl for the second quarter of 2006, and increased 2% from $46.09 per bbl for the prior quarter. The increase from the six months ended June 30, 2006 was due to a narrower Heavy Differential, partially offset by a decrease in WTI benchmark pricing. The decrease in realized crude oil prices from the second quarter of 2006 was due to the widening of the Heavy Differential and the decrease in WTI benchmark price while the increase from the prior quarter was due to the increase in WTI benchmark pricing, partially offset by the widening Heavy Differential and a stronger Canadian dollar relative to the US dollar.

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

North America realized natural gas prices increased 5% to average $7.62 per mcf for the six months ended June 30, 2007 from $7.28 per mcf for the six months ended June 30, 2006. The realized natural gas price in the second quarter of 2007 averaged $7.47 per mcf, an increase of 20% from $6.21 per mcf for the second quarter of 2006, and decreased 4% from $7.79 per mcf for the prior quarter. Fluctuations in natural gas prices from the comparable periods in 2006 were primarily related to weather and storage levels. The decrease in realized natural gas prices from the prior quarter primarily reflected normal seasonality and milder temperatures during 2007, partially offset by the impact of an overall reduction in natural gas drilling activity in Canada in response to industry wide inflationary pressures.

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

	Jun 30 2007	**Mar 31 2007**	**Jun 30 2006**
Wellhead Price (1) (2)			
Light / medium crude oil and NGLs (C$/bbl)	**$ 63.09**	$ 59.48	$ 69.25
Pelican Lake crude oil (C$/bbl)	**$ 44.49**	$ 44.44	$ 56.01
Primary heavy crude oil (C$/bbl)	**$ 42.30**	$ 41.83	$ 51.78
Thermal heavy crude oil (C$/bbl)	**$ 41.09**	$ 40.31	$ 47.64
Natural gas (C$/mcf)	**$ 7.47**	$ 7.79	$ 6.21

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

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

North Sea

North Sea realized crude oil prices increased marginally to average $70.84 per bbl for the six months ended June 30, 2007 from $70.68 per bbl for the six months ended June 30, 2006. Realized crude oil prices in the second quarter of 2007 averaged $73.18 per bbl and increased 6% from $68.83 per bbl for the prior quarter. Realized crude oil prices in the North Sea during the second quarter continued to benefit from the impact of strong European and Asian demand.

Offshore West Africa

Offshore West Africa realized crude oil prices decreased 5% to average $65.34 per bbl for the six months ended June 30, 2007 from $69.10 per bbl for the six months ended June 30, 2006. Realized crude oil prices in the second quarter of 2007 averaged $72.84 per bbl, comparable to $72.97 per bbl for the second quarter of 2006, and increased 24% from $58.60 per bbl for the prior quarter. Realized crude oil prices in Offshore West Africa during the second quarter continued to benefit from the impact of strong European and Asian demand.

Crude Oil Inventory Volumes

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

(bbl)	**Jun 30 2007**	Mar 31 2007	Dec 31 2006
North America, related to pipeline fill	**1,097,526**	1,097,526	1,097,526
North Sea, related to timing of liftings	**350,499**	401,296	910,796
Offshore West Africa, related to timing of liftings	**813,701**	230,623	113,774
	2,261,726	1,729,445	2,122,096

In the second quarter of 2007, net production of approximately 530,000 barrels of crude oil produced in the Company's international operations was deferred and included in inventory at June 30, 2007, reducing cash flow from operations by approximately $34 million.

DAILY PRODUCTION, before royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2007	Mar 31 2007	Jun 30 2006	**Jun 30 2007**	Jun 30 2006
Crude oil and NGLs (bbl/d)					
North America	**240,420**	237,489	234,780	**238,962**	228,901
North Sea	**57,286**	61,869	63,703	**59,565**	62,261
Offshore West Africa	**29,788**	27,643	40,369	**28,722**	40,137
	327,494	327,001	338,852	**327,249**	331,299
Natural gas (mmcf/d)					
North America	**1,696**	1,694	1,448	**1,694**	1,430
North Sea	**15**	15	17	**15**	17
Offshore West Africa	**11**	8	10	**10**	9
	1,722	1,717	1,475	**1,719**	1,456
Total barrel of oil equivalent (boe/d)	**614,461**	613,114	584,611	**613,790**	573,879
Product mix					
Light/medium crude oil and NGLs	**23%**	24%	26%	**24%**	27%
Pelican Lake crude oil	**6%**	5%	5%	**5%**	5%
Primary heavy crude oil	**15%**	15%	16%	**15%**	16%
Thermal heavy crude oil	**9%**	9%	11%	**9%**	10%
Natural gas	**47%**	47%	42%	**47%**	42%

DAILY PRODUCTION, net of royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2007	Mar 31 2007	Jun 30 2006	**Jun 30 2007**	Jun 30 2006
Crude oil and NGLs (bbl/d)					
North America	**206,927**	204,401	205,674	**205,671**	199,246
North Sea	**57,185**	61,754	63,552	**59,457**	62,131
Offshore West Africa	**26,876**	25,897	39,335	**26,389**	39,148
	290,988	292,052	308,561	**291,517**	300,525
Natural gas (mmcf/d)					
North America	**1,444**	1,367	1,183	**1,406**	1,152
North Sea	**15**	15	17	**15**	17
Offshore West Africa	**10**	8	10	**9**	9
	1,469	1,390	1,210	**1,430**	1,178
Total barrel of oil equivalent (boe/d)	**535,789**	523,730	510,243	**529,793**	496,768

Daily production and per barrel statistics are presented throughout the 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 613,790 boe/d for the six months ended June 30, 2007, a 7% increase from the six months ended June 30, 2006. Second quarter total production in 2007 averaged 614,461 boe/d, an increase of 5% from 584,611 boe/d for the second quarter of 2006, and was comparable to 613,114 boe/d for the prior quarter.

Total crude oil and NGLs production for the six months ended June 30, 2007 decreased slightly to 327,249 bbl/d, from 331,299 bbl/d for the six months ended June 30, 2006. In the second quarter of 2007, production decreased 3% to 327,494 bbl/d from 338,852 bbl/d in the second quarter of 2006 and was comparable to 327,001 bbl/d for the prior quarter. The decrease from the comparable periods of 2006 was primarily due to the timing of planned maintenance activities in the North Sea and reduced production from the Baobab Field in Offshore West Africa, partially offset by increased production in North America. Notwithstanding these factors, crude oil and NGLs production in the second quarter of 2007 was at the high end of the Company's previously issued guidance of 313,000 to 329,000 bbl/d.

Natural gas production continued to represent the Company's largest product offering, accounting for 47% of the Company's total production. Natural gas production for the six months ended June 30, 2007 averaged 1,719 mmcf/d compared to 1,456 mmcf/d for the six months ended June 30, 2006. In the second quarter of 2007, natural gas production averaged 1,722 mmcf/d compared to 1,475 mmcf/d for the second quarter of 2006 and 1,717 mmcf/d for the prior quarter. The increase in natural gas production from the comparable periods in 2006 primarily reflected the ACC acquisition completed in the fourth quarter of 2006 and the completion of scheduled natural gas drilling activity in 2007 in advance of spring break-up. The increase from the comparable periods in 2006 was partially offset by production declines due to the Company's strategic reduction in natural gas drilling activity and increased North America crude oil drilling, made in response to sustained low natural gas prices and inflationary cost pressures. Second quarter natural gas production was above the Company's previously issued guidance of 1,677 to 1,698 mmcf/d.

Annual revised production guidance for 2007 is targeted to average between 322,000 and 348,000 bbl/d of crude oil and NGLs and between 1,649 and 1,688 mmcf/d of natural gas. Third quarter 2007 production guidance is targeted to average between 331,000 and 349,000 bbl/d of crude oil and NGLs and between 1,632 and 1,669 mmcf/d of natural gas.

North America

North America crude oil and NGLs production for the six months ended June 30, 2007 increased 4% to average 238,962 bbl/d, up from 228,901 bbl/d for the six months ended June 30, 2006. Production in the second quarter of 2007 increased 2% to average 240,420 bbl/d from 234,780 bbl/d for the second quarter of 2006, and increased 1% from 237,489 bbl/d for the prior quarter. The increase in crude oil and NGLs production from the prior periods was primarily due to the positive results from the Pelican Lake water and polymer flood projects and the ACC acquisition, partially offset by the timing of steaming cycles related to the Company's thermal crude oil projects.

North America natural gas production increased 18% to average 1,694 mmcf/d for the six months ended June 30, 2007 up from 1,430 mmcf/d for the six months ended June 30, 2006. In the second quarter of 2007, natural gas production increased 17% to 1,696 mmcf/d from 1,448 mmcf/d for the second quarter of 2006, and was comparable to 1,694 mmcf/d for the prior quarter. The increase in natural gas production from the comparable periods in 2006 reflected the impact of the ACC acquisition and the completion of scheduled natural gas drilling activity in advance of spring break up. The increase was partially offset by production declines due to the Company's strategic decision to reduce natural gas drilling activity.

North Sea

North Sea crude oil production averaged 59,565 bbl/d for the six months ended June 30, 2007, a decrease of 4% from 62,261 bbl/d for the six months ended June 30, 2006. Crude oil production in the second quarter of 2007 decreased 10% to 57,286 bbl/d from 63,703 bbl/d for the second quarter of 2006 and decreased 7% from 61,869 bbl/d for the prior quarter. Production levels for the second quarter of 2007 were in line with expectations and reflected the planned maintenance shutdowns carried out during the quarter on the water injection systems on the Ninian platforms.

Crude oil production volumes are anticipated to decrease marginally in the third quarter of 2007 due to planned maintenance shutdowns at Ninian North, Ninian Central, T-Block and B-Block.

Offshore West Africa

Offshore West Africa crude oil production decreased 28% to average 28,722 bbl/d for the six months ended June 30, 2007 from 40,137 bbl/d for the six months ended June 30, 2006. Second quarter 2007 production decreased 26% to 29,788 bbl/d from 40,369 bbl/d for the second quarter of 2006, and increased 8% from 27,643 bbl/d for the prior quarter. Second quarter production decreased from the comparable period in 2006 due to continued challenges with sand and solids production at the Baobab Field where 5 production wells remain shut in. The Company has secured a deepwater rig for mobilization expected in late 2007 or early 2008 that should enable the Company to execute its defined plan to determine the cause of the sand screen failings and may return certain of these shut-in wells to production over the course of 2008.

ROYALTIES

	Three Months Ended			Six Months Ended	
	Jun 30 2007	Mar 31 2007	Jun 30 2006	**Jun 30 2007**	Jun 30 2006
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 6.58**	$ 6.42	$ 6.81	**$ 6.50**	$ 5.77
North Sea	**$ 0.13**	$ 0.13	$ 0.17	**$ 0.13**	$ 0.15
Offshore West Africa	**$ 7.12**	$ 3.70	$ 1.87	**$ 5.32**	$ 1.71
Company average	**$ 5.46**	$ 4.92	$ 5.14	**$ 5.19**	$ 4.34
Natural gas ($/mcf) [1]					
North America	**$ 1.11**	$ 1.50	$ 1.13	**$ 1.30**	$ 1.43
North Sea	**$ -**	$ -	$ -	**$ -**	$ -
Offshore West Africa	**$ 0.59**	$ 0.38	$ 0.14	**$ 0.50**	$ 0.13
Company average	**$ 1.10**	$ 1.48	$ 1.11	**$ 1.29**	$ 1.40
Company average ($/boe) [1]	**$ 5.99**	$ 6.76	$ 5.80	**$ 6.37**	$ 6.11
Percentage of revenue [2]					
Crude oil and NGLs	**10%**	10%	9%	**10%**	8%
Natural gas	**15%**	19%	18%	**17%**	20%
Boe	**12%**	14%	12%	**13%**	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 six months ended June 30, 2007 reflected increased realized crude oil prices and the full recovery of the Company's capital investments in the Primrose North and South Fields in the third quarter of 2006. Upon full recovery, Crown royalty rates on the Primrose North and South Fields increased from 1% of gross revenue to 25% of gross revenue less operating, capital and abandonment costs. Crude oil and NGLs royalties averaged approximately 14% of gross revenues in 2007, compared to 12% for the second quarter of 2006. Crude oil and NGLs royalties per bbl are anticipated to average approximately 14% to 16% of gross revenues for the year.

Natural gas royalties per mcf generally fluctuate with natural gas prices. Natural gas royalties averaged approximately 15% of gross revenues in the second quarter of 2007 compared to 18% for the second quarter of 2006 and 19% for the prior quarter. Natural gas royalties decreased in the second quarter of 2007 compared to prior periods due to the impact of certain adjustments, and are anticipated to average approximately 18% to 20% of gross revenues for the year.

North Sea

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

Offshore West Africa

Offshore West Africa production is governed by the terms of the various Production Sharing Contracts ("PSCs"). Under the PSCs, revenues are divided into cost recovery oil and profit oil. Cost recovery oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the Government State Oil Company. These combined revenues are reported as sales revenue. 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 to royalty expense and current income tax expense in accordance with the PSCs. The Company's capital investments in the Espoir Fields were fully recovered in the first quarter of 2007, increasing royalty rates and current income taxes in accordance with the PSCs. The Company's capital investment in the Baobab Field is not expected to be fully recovered until approximately 2010 - 2011 due to the ongoing production curtailments resulting from limitations to sand screen effectiveness.

Royalty rates as a percentage of gross revenue averaged approximately 10% for the second quarter of 2007 compared to 3% for second quarter of 2006 and 6% for the prior quarter. The increase in royalty rates from the comparable periods was due to the Company's full recovery of its capital investment in the Espoir Field in the first quarter of 2007 and the resulting increase in profit oil on which the Government's entitlement is based. Offshore West Africa royalty rates are anticipated to be 13% to 15% of gross revenues for the year.

PRODUCTION EXPENSE

	Three Months Ended			Six Months Ended	
	Jun 30 2007	Mar 31 2007	Jun 30 2006	**Jun 30 2007**	Jun 30 2006
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 13.98**	$ 13.00	$ 11.71	**$ 13.50**	$ 11.33
North Sea	**$ 22.11**	$ 18.57	$ 17.18	**$ 20.21**	$ 17.02
Offshore West Africa	**$ 7.98**	$ 8.93	$ 5.61	**$ 8.48**	$ 5.85
Company average	**$ 15.01**	$ 13.81	$ 11.92	**$ 14.40**	$ 11.63
Natural gas ($/mcf) (1)					
North America	**$ 0.87**	$ 0.95	$ 0.79	**$ 0.91**	$ 0.79
North Sea	**$ 2.26**	$ 2.58	$ 1.47	**$ 2.42**	$ 1.37
Offshore West Africa	**$ 1.10**	$ 1.48	$ 0.36	**$ 1.26**	$ 0.65
Company average	**$ 0.89**	$ 0.97	$ 0.80	**$ 0.93**	$ 0.80
Company average ($/boe) (1)	**$ 10.44**	$ 10.10	$ 8.85	**$ 10.27**	$ 8.66

(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 six months ended June 30, 2007 increased to $13.50 per bbl from $11.33 per bbl for the six months ended June 30, 2006. In the second quarter of 2007, production costs increased to $13.98 per bbl from $11.71 per bbl for the second quarter of 2006 and from $13.00 per bbl for the prior quarter. Second quarter production expense primarily reflected continued increasing industry-wide costs in the heavy oil industry, the timing of steaming cycles related to the Company’s thermal crude oil projects, increased costs associated with additional injection wells related to the Company’s Pelican Lake water and polymer flood projects and increased costs related to fuel and property taxes.

North America natural gas production expense per mcf for the second quarter of 2007 increased over the comparable periods in 2006 primarily due to industry-wide cost pressures. In the second quarter of 2007, natural gas well servicing costs in Canada began to decline due to lower industry activity, resulting in a decrease in production expense compared to the first quarter of 2007.

North Sea

North Sea crude oil production expense varied on a per barrel basis from the comparable periods due to planned maintenance shutdowns, varying production volumes on a relatively fixed cost base and the timing of liftings from various fields. The Company has revised its North Sea production expense guidance for 2007 to between $19.50 to $20.50 per barrel.

Offshore West Africa

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

MIDSTREAM

($ millions)	Three Months Ended Jun 30 2007	Mar 31 2007	Jun 30 2006	Six Months Ended Jun 30 2007	Jun 30 2006
Revenue	**$ 17**	$ 19	$ 17	**$ 36**	$ 35
Production expense	**5**	6	6	**11**	11
Midstream cash flow	**12**	13	11	**25**	24
Depreciation	**2**	2	2	**4**	4
Segment earnings before taxes	**$ 10**	$ 11	$ 9	**$ 21**	$ 20

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 Jun 30 2007	Mar 31 2007	Jun 30 2006	Six Months Ended Jun 30 2007	Jun 30 2006
Expense ($ millions)	**$ 718**	$ 707	$ 555	**$ 1,425**	$ 1,074
$/boe (2)	**$ 12.95**	$ 12.73	$ 10.66	**$ 12.84**	$ 10.62

(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 six and three months ended June 30, 2007 increased in total and on a boe basis from the comparable periods in 2006 and the prior quarter. The increase in DD&A expense was primarily as a result of increased sales volumes combined with overall increases in finding and development costs associated with crude oil and natural gas exploration, a higher depletion base related to the ACC acquisition, and increased estimated future costs to develop the Company's proved undeveloped reserves.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three Months Ended Jun 30 2007	Mar 31 2007	Jun 30 2006	Six Months Ended Jun 30 2007	Jun 30 2006
Expense ($ millions)	**$ 17**	$ 18	$ 16	**$ 35**	$ 33
$/boe (1)	**$ 0.30**	$ 0.32	$ 0.32	**$ 0.31**	$ 0.33

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

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

ADMINISTRATION EXPENSE

	Three Months Ended			Six Months Ended	
	Jun 30 2007	Mar 31 2007	Jun 30 2006	**Jun 30 2007**	Jun 30 2006
Net expense ($ millions)	**$ 53**	$ 60	$ 40	**$ 113**	$ 82
$/boe [1]	**$ 0.96**	$ 1.08	$ 0.78	**$ 1.02**	$ 0.81

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

Administration expense for the six months ended June 30, 2007 increased in total and on a boe basis from the six months ended June 30, 2006 primarily due to increased staffing costs, including costs related to the Company's share bonus program. The decrease in administration expense from the prior quarter in 2007 was primarily due to decreased staffing costs associated with the effect of graded vesting on the share bonus program.

STOCK-BASED COMPENSATION EXPENSE (RECOVERY)

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2007**	Mar 31 2007	Jun 30 2006	**Jun 30 2007**	Jun 30 2006
Stock option plan expense (recovery)	**$ 106**	$ 25	$ (34)	**$ 131**	$ 98

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

The Company recorded a $131 million ($91 million after-tax) stock-based compensation expense as a result of the 14% increase in the Company's share price in the six months ended June 30, 2007, and a $106 million ($74 million after-tax) stock-based compensation expense as a result of the 11% increase in the Company's share price for the three months ended June 30, 2007 (Company's share price as at: June 30, 2007 – C$70.78; March 31, 2007 – C$63.75; December 31, 2006 – C$62.15; June 30, 2006 – C$61.72). As required by GAAP, the Company's outstanding stock options are valued each reporting period based on the difference between the exercise price of the stock options and the market price of the Company's common shares, pursuant to a graded vesting schedule. The liability is revalued quarterly to reflect changes in the market price of the Company's common shares and the options exercised or surrendered in the period, with the net change recognized in net earnings, or capitalized during the construction period in the case of the Horizon Project. For the six months ended June 30, 2007, the Company capitalized $39 million in stock-based compensation on the Horizon Project (June 30, 2006 - $66 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 June 30, 2007. In periods when substantial stock price changes occur, the Company is subject to significant earnings volatility.

For the six months ended June 30, 2007, the Company paid $221 million for stock options surrendered for cash settlement (June 30, 2006 - $183 million).

INTEREST EXPENSE

($ millions, except per boe amounts)	Three Months Ended Jun 30 2007	Mar 31 2007	Jun 30 2006	Six Months Ended Jun 30 2007	Jun 30 2006
Interest expense, gross	**$ 158**	$ 154	$ 69	**$ 312**	$ 127
Less: capitalized interest, Horizon Project	**81**	71	41	**152**	74
Interest expense, net	**$ 77**	$ 83	$ 28	**$ 160**	$ 53
$/boe [1]	**$ 1.40**	$ 1.49	$ 0.53	**$ 1.44**	$ 0.52
Average effective interest rate	**5.4%**	5.4%	5.7%	**5.4%**	5.7%

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

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

The Company's average effective interest rate for the period ended June 30, 2007 reflected the impact of a stronger Canadian dollar, partially offset by higher cost US dollar denominated debt issued in March 2007.

RISK MANAGEMENT ACTIVITIES

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

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

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

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

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

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

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

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

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

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

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

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

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

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

All derivative financial instruments are recognized at estimated fair value on the consolidated balance sheet at each balance sheet date. The estimated fair value of derivative instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. However, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

The Company formally documents all derivative financial instruments designated as hedging transactions at the inception of the hedging relationship, in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated, both at inception of the hedge and on an ongoing basis.

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

The Company enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. Changes in the fair value of interest rate swap contracts designated as fair value hedges and corresponding changes in the fair value of the hedged long-term debt are included in interest expense in consolidated net earnings. Changes in the fair value of non-designated interest rate swap contracts are included in risk management activities in consolidated net earnings.

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

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

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

RISK MANAGEMENT

($ millions)	Three Months Ended Jun 30 2007	Mar 31 2007	Jun 30 2006	Six Months Ended Jun 30 2007	Jun 30 2006
Realized loss (gain)					
Crude oil and NGLs financial instruments	**$ 100**	$ (5)	$ 421	**$ 95**	$ 753
Natural gas financial instruments	**(8)**	(83)	(14)	**(91)**	42
	$ 92	$ (88)	$ 407	**$ 4**	$ 795
Unrealized loss (gain)					
Crude oil and NGLs financial instruments	**$ 64**	$ 330	$ (10)	**$ 394**	$ 104
Natural gas financial instruments	**(121)**	206	(12)	**85**	(116)
Interest rate swaps	**-**	-	(4)	**-**	(6)
	$ (57)	$ 536	$ (26)	**$ 479**	$ (18)
Total	**$ 35**	$ 448	$ 381	**$ 483**	$ 777

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

	Three Months Ended Jun 30 2007	Mar 31 2007	Jun 30 2006	Six Months Ended Jun 30 2007	Jun 30 2006
Crude oil and NGLs ($/bbl) (1)	**$ 3.41**	$ (0.17)	$ 14.18	**$ 1.61**	$ 13.15
Natural gas ($/mcf) (1)	**$ (0.05)**	$ (0.54)	$ (0.11)	**$ (0.29)**	$ 0.16

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

Details related to outstanding derivative financial instruments at June 30, 2007 are disclosed in note 10 to the Company's unaudited interim consolidated financial statements. As at December 31, 2006, the net unrecognized asset related to the estimated fair values of derivative financial instruments designated as hedges was $222 million.

As effective as the Company's hedges are against reference commodity prices, a substantial portion of the derivative financial instruments entered into by the Company do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The change in the fair value of the non-designated hedges is based on prevailing forward commodity prices in effect at the end of each reporting period and is reflected in risk management activities in consolidated net earnings. The cash settlement amount of the risk management derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the derivative financial instruments, as compared to their mark-to-market value at June 30, 2007. Due to changes in the crude oil and natural gas forward pricing, and the reversal of prior period unrealized gains and losses, the Company recorded a net unrealized loss of $479 million ($327 million after-tax) on its commodity risk management activities for the six months ended June 30, 2007, including a $57 million ($35 million after-tax) unrealized gain for the three months ended June 30, 2007 (March 31, 2007 – unrealized loss of $536 million, $362 million after-tax; June 30, 2006 - unrealized gain of $26 million, $17 million after-tax).

FOREIGN EXCHANGE

($ millions)	Three Months Ended Jun 30 2007	Mar 31 2007	Jun 30 2006	Six Months Ended Jun 30 2007	Jun 30 2006
Net realized foreign exchange loss	**$ 26**	$ 5	$ 12	**$ 31**	$ 7
Net unrealized foreign exchange gain [1]	**(250)**	(32)	(58)	**(282)**	(48)
	$ (224)	$ (27)	$ (46)	**$ (251)**	$ (41)

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

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

The net realized foreign exchange loss for the three and six months ended June 30, 2007 was primarily the result of settlement of working capital items denominated in US dollars or UK pounds sterling and the impact of foreign exchange rate fluctuations. The net unrealized foreign exchange gain for the three and six months ended June 30, 2007 was primarily related to the second quarter strengthening of the Canadian dollar in relation to the US dollar with respect to the US dollar debt. Included in the net unrealized gain for the six months ended June 30, 2007 is an unrealized loss of $207 million (March 31, 2007 – unrealized loss of $37 million) related to the impact of the cross currency interest rate swaps. The Canadian dollar ended the second quarter at US$0.9404 compared to US$0.8674 at March 31, 2007 (June 30, 2006 - US$0.8969).

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

TAXES

($ millions, except income tax rates)	Three Months Ended Jun 30 2007	Mar 31 2007	Jun 30 2006	Six Months Ended Jun 30 2007	Jun 30 2006
Taxes other than income tax					
Current	**$ 9**	$ 66	$ 59	**$ 75**	$ 94
Deferred	**20**	(3)	18	**17**	44
	$ 29	$ 63	$ 77	**$ 92**	$ 138
Current income tax					
North America	**$ 12**	$ 25	$ 22	**$ 37**	$ 40
North Sea	**54**	35	(1)	**89**	-
Offshore West Africa	**16**	10	16	**26**	29
	$ 82	$ 70	$ 37	**$ 152**	$ 69
Future income tax expense (recovery)	**$ 116**	$ 100	$ (224)	**$ 216**	$ 44
Effective income tax rate	**19.1%(1)**	38.7%	(21.9)%(3)	**24.9%(1)**	9.4%(2)(3)

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

(2) Includes the effect of a one time charge of $110 million related to the increased supplementary charge on oil and gas profits in the UK North Sea, substantively enacted during the first quarter of 2006.

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

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

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

CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended **Jun 30 2007**	Mar 31 2007	Jun 30 2006	Six Months Ended **Jun 30 2007**	Jun 30 2006
Expenditures on property, plant and equipment					
Net property acquisitions	**$ 15**	$ 46	$ 7	**$ 61**	$ 19
Land acquisition and retention	**22**	29	54	**51**	153
Seismic evaluations	**34**	50	35	**84**	87
Well drilling, completion and equipping	**288**	714	418	**1,002**	1,354
Pipeline and production facilities	**243**	334	233	**577**	733
Total net reserve replacement expenditures	**602**	1,173	747	**1,775**	2,346
Horizon Project:					
Phase 1 construction costs	**704**	674	680	**1,378**	1,296
Phases 2 and 3 costs	**19**	44	6	**63**	7
Capitalized interest, stock-based compensation and other	**118**	91	96	**209**	165
Total Horizon Project	**841**	809	782	**1,650**	1,468
Midstream	**-**	2	6	**2**	9
Abandonments [2]	**13**	20	17	**33**	32
Head office	**4**	5	6	**9**	12
Total net capital expenditures	**$ 1,460**	$ 2,009	$ 1,558	**$ 3,469**	$ 3,867
By segment					
North America	**$ 419**	$ 998	$ 569	**$ 1,417**	$ 1,973
North Sea	**136**	138	149	**274**	287
Offshore West Africa	**46**	36	27	**82**	77
Other	**1**	1	2	**2**	9
Horizon Project	**841**	809	782	**1,650**	1,468
Midstream	**-**	2	6	**2**	9
Abandonments [2]	**13**	20	17	**33**	32
Head office	**4**	5	6	**9**	12
Total	**$ 1,460**	$ 2,009	$ 1,558	**$ 3,469**	$ 3,867

(1) The net capital expenditures do not include non-cash property, plant and equipment additions or disposals.

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

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

Net capital expenditures in the six months ended June 30, 2007 were $3,469 million compared to $3,867 million in the six months ended June 30, 2006. The capital expenditures reflected the continued progress on the Company’s larger, future growth projects, most notably the Horizon Project, as well as overall industry-wide inflationary pressures, offset by an overall strategic reduction in the North America natural gas drilling program.

In the six months ended June 30, 2007, the Company drilled a total of 783 net wells consisting of 207 natural gas wells, 271 crude oil wells, 241 stratigraphic test and service wells and 64 wells that were dry. This compared to 1,031 net wells drilled in the six months ended June 30, 2006. The Company achieved an overall success rate of 88% for the six months ended June 30, 2007, excluding stratigraphic test and service wells, compared to 91% for the six months ended June 30, 2006**.**

Net capital expenditures in the second quarter of 2007 were $1,460 million compared to $1,558 million in the second quarter of 2006 and $2,009 million in the prior quarter. Second quarter 2007 capital expenditures decreased from the comparable period in 2006 due to the Company’s strategic reduction in natural gas drilling activity, and decreased from the first quarter of 2007 as a result of reduced drilling activity due to spring break-up.

In the second quarter of 2007, the Company drilled a total of 95 net wells consisting of 6 natural gas wells, 78 crude oil wells, 7 stratigraphic test and service wells and 4 wells that were dry. This compared to 141 net wells in the second quarter of 2006 and 688 net wells in the prior quarter. The Company achieved an overall success rate of 95% for the second quarter of 2007, excluding stratigraphic test and service wells, compared to 95% for the second quarter of 2006 and 87% for the first quarter of 2007**.**

North America

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

During the six months ended June 30, 2007, the Company targeted 252 net natural gas wells, including 49 wells in Northeast British Columbia, 94 wells in the Northern Plains region, 82 wells in Northwest Alberta, and 27 wells in the Southern Plains region. The Company also targeted 285 net crude oil wells during the six months ended June 30, 2007. The majority of these wells were concentrated in the Company’s crude oil Northern Plains region where 166 heavy crude oil wells, 76 Pelican Lake crude oil wells, 23 thermal crude oil wells and 5 light crude oil wells were drilled. Another 15 wells targeting light crude oil were drilled outside the Northern Plains region.

Due to significant changes in relative commodity prices between crude oil and natural gas, the Company continues to access its large crude oil drilling inventory to maximize value in both the short and long term. With the Company’s focus on drilling crude oil wells in the first six months of 2007, natural gas drilling activities were reduced to manage overall capital spending. Deferred natural gas well locations have been retained in the Company’s prospect inventory, and will be drilled as natural gas commodity prices improve. Drilling on ACC acquired lands was optimized as part of the overall capital program.

In November of 2005, the Company announced a phased expansion of its In-Situ Oil Sands Assets. As part of the development, the Company is continuing to develop its Primrose thermal projects. During the first six months of 2007, the Company drilled 130 stratigraphic test wells and observation wells, 2 water source wells and 23 thermal oil wells. Overall Primrose thermal production for the six months ended June 30, 2007 increased to approximately 57,000 bbl/d from approximately 55,000 bbl/d for the six months ended June 30, 2006.

The Primrose East Expansion, a new facility located 15 kilometres from the existing Primrose South steam plant and 25 kilometres from the Wolf Lake central processing facility, is anticipated to add approximately 40,000 bbl/d. The Primrose East Expansion received Board of Directors’ sanction in 2006 and The Alberta Energy and Utilities Board regulatory approval in the first quarter of 2007. Drilling and construction are currently underway, and production is targeted to commence in 2009.

The next phase of the Company's In-Situ Oil Sands Assets expansion is the Kirby project located 120 kilometres north of the existing Primrose facilities. The Kirby project is anticipated to add approximately 30,000 bbl/d of production growth. The Company is targeting to file its formal regulatory application documents for this project in the latter half of 2007. Final corporate sanction may depend upon the results of potential changes to royalty regimes and environmental regulations, and their associated costs.

Development of new pads and secondary recovery conversion projects at Pelican Lake continued as expected throughout the second quarter of 2007. Drilling consisted of 40 horizontal wells, with plans to drill 52 additional horizontal wells for the remainder of 2007. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 34,000 bbl/d for the second quarter of 2007 compared to 30,000 bbl/d for the second quarter of 2006 and 32,000 bbl/d for the prior period.

Originally announced in the fall of 2005, the scoping study for the Canadian Natural Upgrader, outside of the Horizon Project, continued into the first quarter of 2007. The terms of reference for this study involved the evaluation of product alternatives, location, technology, gasification and integration with existing assets using the same disciplined approach utilized in the Horizon Project. The next steps in this process would include a Design Basis Memorandum ("DBM") and Engineering Design Specification ("EDS"), which would be required to be completed prior to construction and sanctioning of the project by the Board of Directors.

Based upon the results of the scoping study, which identified growing concerns relating to increased environmental costs for upgraders located in Canada, inflationary capital cost pressures and narrowing heavy oil differentials in North America, the Company has, at this point in time, deferred the DBM and EDS pending clarification on the cost of future environmental legislation and a more stable cost environment.

In the third quarter of 2007, the Company's overall drilling activity in North America is expected to be comprised of 121 natural gas wells and 147 crude oil wells excluding stratigraphic and service wells.

Horizon Project

Work progress on the Horizon Project was 75% complete at the end of the second quarter. First production continues to be targeted to commence in the third quarter of 2008. The project status as at June 30, 2007 was as follows:

- Overall detailed engineering 97% completed and substantially complete in most areas;
- Procurement 95% completed with over $5.4 billion in purchase orders and contracts awarded;
- Overall construction progress is 63% complete.
- Mine overburden removal approximately 54% completed and is 1% ahead of schedule.
- Construction of cofferdam for the Tar River Diversion completed in Mining.
- Fabrication of Crushing Plants, Surge Facility and Conveyor Structure is 100% complete in the Ore Preparation Plant.
- Started erection of Conveyors in Ore Preparation.
- Completed Hot Water Tank in Extraction.
- Hydro-tested Primary Separation Cells and Hot Water Tank.
- Completed construction and hydro-testing of Inclined Plate Settlers in Froth Treatment.
- Flare Stacks installed in Upgrading.
- Mechanically completed Cooling Tower piping.
- Mechanically completed Inhibited Water and Cooling Water Pumphouse buildings.
- 42" Water Pipeline completed.
- Wet Gas Compressor received and installed.
- Completed installation of Coker and Diluent Recovery Unit process structures.
- Completed interconnecting welding of Primary Upgrading's piperacks.
- Energized main electrical substations R1/R2.

Major activities for the third quarter of 2007 will include:

- Complete construction of Raw Water Pond;
- Extraction Plant hydro-testing;
- Start of pre-commissioning activities in all Bitumen Production Areas;
- Permanent power energized in R1/R2 corridors pumphouses;
- Electrically energize Main Electrical Substation; and
- Start commissioning of Recycle Water Pond.

In 2005, the Board of Directors of the Company approved the construction costs for Phase 1 of the Horizon Project, with an approved budget of $6.8 billion. Cumulative construction spending to June 30, 2007 was approximately $5.4 billion. Final construction costs for Phase 1 are expected to exceed the approved budget by 5% to 12% primarily due to inflationary cost pressures.

North Sea

In the second quarter of 2007, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During the quarter, 3.7 net wells were drilled, with an additional 1.9 net wells drilling at the end of the quarter.

The development of the Lyell Field progressed during the second quarter. Tranche 1 of the Lyell Field development comprises 2 production wells scheduled for completion in 2007, and one production well and one well workover scheduled for completion in 2008. Full capacity production from the Lyell Field has been deferred to 2008 to optimize capital allocation in the North Sea.

During the second quarter of 2007, construction of the Columba E Raw Water Injection project continued. Commissioning was completed and 2 water injection wells were delivered. Production is anticipated to reach full capacity in 2008.

Offshore West Africa

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

First crude oil from West Espoir commenced in mid-2006 from 3 production wells and 2 injector wells. An additional production well was added during the first quarter of 2007, with 2 additional production wells being brought on line during the second quarter of 2007. West Espoir development drilling is expected to continue until 2008 with producers and injectors being brought on line as they are completed.

The Company purchased a 90% interest in the Olowi PSC offshore Gabon in 2005, and received Government approval and Board sanction for development in 2006. Development plans include a floating production, storage and offtake vessel ("FPSO"), handling production from 4 shallow-water producing platforms. During 2006 and the first half of 2007, the Company signed a lease agreement for a FPSO with a primary term of ten years, commencing in 2008, and awarded additional contracts for a drilling rig and for the construction of the wellhead towers. Drilling is scheduled to commence in mid-2008 with first crude oil anticipated in late 2008. Olowi production is targeted to plateau at approximately 20,000 bbl/d.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Jun 30 2007**		Mar 31 2007		Dec 31 2006		Jun 30 2006
Working capital deficit (1)	**$**	**860**	$	1,104	$	832	$	1,554
Long-term debt (2)	**$**	**10,958**	$	11,307	$	11,043	$	5,004
Shareholders' equity								
Share capital	**$**	**2,649**	$	2,635	$	2,562	$	2,516
Retained earnings		**9,169**		8,374		8,141		6,798
Accumulated other comprehensive income (loss)		**62**		(45)		(13)		(12)
Total	**$**	**11,880**	$	10,964	$	10,690	$	9,302
Debt to book capitalization (2) (3)		**48.0%**		50.8%		50.8%		35.0%
Debt to market capitalization (2)		**22.3%**		24.8%		24.8%		13.1%
After tax return on average common shareholders' equity (4)		**23.8%**		27.5%		26.9%		29.3%
After tax return on average capital employed (2) (5)		**13.9%**		16.5%		17.2%		20.2%

(1) Calculated as current assets less current liabilities.

(2) Long-term debt at June 30, 2007 is stated at its carrying value, net of fair value adjustments, original issue discounts and transactions costs. Amounts for periods prior to January 1, 2007 were not adjusted for these items.

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

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

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

The Company's capital resources at June 30, 2007 consisted primarily of cash flow from operations, available credit facilities and access to debt capital markets. Cash flow from operations is dependent on factors discussed in the Risks and Uncertainties section of the Company's December 31, 2006 annual MD&A**.** The Company's ability to renew existing credit facilities and raise new debt is also dependent upon these factors, as well as maintaining an investment grade debt rating and the condition of capital and credit markets. Management believes internally generated cash flows supported by the implementation of the Company's hedge policy, the flexibility of its capital expenditure programs supported by its five- and ten-year financial plans, the Company's existing credit facilities and the Company's ability to raise new debt on commercially acceptable terms, will be sufficient to sustain its operations and support its growth strategy. The Company's current debt ratings are BBB (high) with a negative trend by DBRS, Baa2 with a stable outlook by Moody's Investor Services, Inc. and BBB with a stable outlook by Standard and Poors Corporation.

At June 30, 2007, the Company had undrawn bank lines of credit of $1,427 million. Details related to the Company's long-term debt at June 30, 2007 are disclosed in note 4 to the Company's unaudited interim consolidated financial statements.

At June 30, 2007, the Company's working capital deficit was $860 million and included the current portion of the stock-based compensation liability of $453 million and the current portion of the net mark-to-market liability for risk management derivative financial instruments of $149 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 June 30, 2007.

The Company believes it has the necessary financial capacity to complete the Horizon Project, while at the same time not compromising conventional crude oil and natural gas growth opportunities. The financing of Phase 1 of the Horizon Project development is guided by the competing principles of retaining as much direct ownership interest as possible while maintaining a strong balance sheet. Existing proved development projects, which have largely been funded prior to June 30, 2007, such as Baobab, Primrose and Espoir, and the acquisition of ACC, are anticipated to provide identified growth in production volumes in 2007 through 2009, and generate incremental free cash flows during this period.

Including the additional debt issued to complete the ACC acquisition in the fourth quarter of 2006, long-term debt was $10,958 million at June 30, 2007, resulting in a debt to book capitalization level of 48.0% (March 31, 2007 – 50.8%; December 31, 2006 – 50.8%; June 30, 2006 –35.0%). While this ratio is above the 35% to 45% range targeted by management, the Company remains committed to maintaining a strong balance sheet and flexible capital structure, and expects its debt to book capitalization ratio to be near the midpoint of the range in late 2008. While the Company believes that its balance sheet has the strength and flexibility to complete Phase 1 of the Horizon Project and its planned capital expenditure programs, the Company has hedged a significant portion of its natural gas and crude oil production for 2007 and 2008 at prices that protect investment returns. In the future, the Company may also consider the divestiture of non-strategic and non-core properties to gain additional balance sheet flexibility.

The Company's commodity hedging program reduces the risk of volatility in commodity price markets and supports the Company's cash flow for its capital expenditure program throughout the Horizon Project construction period. This program allows for the hedging of up to 75% of the near 12 months budgeted production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. In accordance with the policy, approximately 60% of expected crude oil volumes and approximately 70% of expected natural gas volumes are hedged for the remainder of 2007. In addition, 77,000 bbl/d of crude oil volumes are protected by WTI put options for the remainder of 2007 at a strike price of US$60.00 per barrel.

The Company has hedged 220,000 bbl/d of crude oil volumes for the year 2008. Of the 220,000 bbl/d, 20,000 bbl/d are hedged by Mayan price collars with a US$50.00 floor, 150,000 bbl/d are hedged by WTI price collars with a US$60.00 floor and 50,000 bbl/d are hedged by WTI put options with a US$55.00 strike price. The Company has also entered into an additional 50,000 bbl/d of WTI price collars with a US$60.00 floor for the first quarter of 2008. In addition, 900,000 GJ/d of natural gas volumes are hedged by AECO price collars for the first quarter of 2008; 400,000 GJ/d with a $7.00 floor and 500,000 GJ/d with a $7.50 floor.

The Company has also reduced its 2007 conventional crude oil and natural gas capital budget by $900 million compared to 2006 capital spending, while maintaining the capital expenditures to complete Phase 1 of the Horizon Project.

Long-term debt

As at June 30, 2007, the Company had in place unsecured bank credit facilities of $6,212 million, comprised of:

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

During the second quarter of 2007, one of the 5-year revolving syndicated credit facilities was increased to $2,230 million and the $500 million demand credit facility was terminated. The revolving syndicated credit facilities were extended and now mature June 2012. Both facilities are extendible annually for one year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date.

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

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $345 million, including $300 million related to the Horizon Project, were outstanding at June 30, 2007.

Medium-term notes

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

The Company has $1,600 million remaining on its $2,000 million shelf prospectus filed in August 2005 that allows for the issue of medium-term notes in Canada until September 2007. If issued, these securities will bear interest as determined at the date of issuance.

Senior unsecured notes

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

US dollar debt securities

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

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

Share capital

As at June 30, 2007, there were 539,385,000 common shares outstanding and 27,768,000 stock options outstanding. As at July 31, 2007, the Company had 539,459,000 common shares outstanding and 27,281,000 stock options outstanding.

In January 2007, the Company renewed its Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the 12-month period beginning January 24, 2007 and ending January 23, 2008, up to 26,941,730 common shares or 5% of the outstanding common shares of the Company then outstanding on the date of the announcement. As at July 31, 2007, the Company had not purchased any shares during 2007 under the Normal Course Issuer Bid.

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

Commitments and off balance sheet arrangements

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. These commitments primarily relate to debt repayments, operating leases relating to office space and offshore FPSOs and drilling rigs, and firm commitments for gathering, processing and transmission services, as well as expenditures relating to asset retirement obligations. As at June 30, 2007, no entities were consolidated under the Canadian Institute of Chartered Accountants Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at June 30, 2007:

($ millions)	Remaining 2007	2008	2009	2010	2011	Thereafter
Product transportation and pipeline (1)	$ 133	$ 217	$ 147	$ 135	$ 105	$ 1,055
Offshore equipment operating lease (2)	$ 195	$ 48	$ 48	$ 48	$ 46	$ 108
Offshore drilling (3) (4)	$ 187	$ 168	$ 50	$ 50	$ 48	$ 162
Asset retirement obligations (5)	$ 2	$ 3	$ 3	$ 4	$ 4	$ 4,422
Long-term debt (6)	$ -	$ 42	$ 2,377	$ -	$ 425	$ 5,798
Office lease	$ 15	$ 31	$ 31	$ 32	$ 22	$ -
Electricity and other	$ 89	$ 158	$ 165	$ 18	$ 1	$ -

(1) The Company entered into a 25-year pipeline transportation agreement commencing in 2008, related to future crude oil production. The agreement is renewable for successive 10-year periods at the Company's option. During the initial term, annual toll payments before operating costs will be approximately $35 million.

(2) Offshore equipment operating leases are primarily comprised of obligations related to floating production, storage and offtake vessels ("FPSO"). During 2006, the Company entered into an agreement to lease an additional FPSO commencing in 2008, in connection with the planned offshore development in Gabon, Offshore West Africa. The new FPSO lease agreement contains cancellation provisions at the option of the Company, subject to escalating termination payments throughout 2007 to a maximum of US$395 million. As at June 30, 2007, US$140 million of potential termination payments have been included as a 2007 commitment in this table.

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

(4) 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. In addition to incurred construction costs, the wellhead towers agreement contains cancellation provisions at the option of the Company, subject to varying termination payments based on pro-rata percentages of the contract price throughout June 2009, subject to a maximum of US$95 million. The drilling rig agreement contains cancellation provisions at the option of the Company, subject to escalating termination payments to a maximum of US$55 million in 2008. As at June 30, 2007, US$120 million of potential cancellation and termination payments have been included as a 2007 commitment in this table.

(5) Amounts represent management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2007 – 2011 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(6) The long-term debt represents principal repayments only and do not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $2,431 million of revolving bank credit facilities due to the extendable nature of the facilities.

In 2005, the Board of Directors of the Company approved the construction costs for Phase 1 of the Horizon Project, with an approved budget of $6.8 billion. Cumulative construction spending to June 30, 2007 was approximately $5.4 billion. Final construction costs for Phase 1 are expected to exceed the approved budget by 5% to 12%.

Legal proceedings

The Company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The Company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

Critical accounting estimates and change in accounting policies

The preparation of financial statements requires the Company to make judgements, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. Actual results could differ from those estimates. A comprehensive discussion of the Company's significant accounting policies is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2006.

For the impact of new accounting standards related to financial instruments and comprehensive income, please refer to Risk Management Activities on page 31 of this MD&A and note 2 of the unaudited interim consolidated financial statements as at June 30, 2007.

SENSITIVITY ANALYSIS [1]

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 second quarter of 2007, and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only; all other variables are held constant.

	Cash flow from operations ($ millions)	Cash flow from operations (per common share, basic)	Net earnings ($ millions)	Net earnings (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl [2]				
Excluding financial derivatives	$ 96	$ 0.18	$ 70	$ 0.13
Including financial derivatives	$ 87 - 96	$ 0.16 - 0.18	$ 63 - 70	$ 0.12 - 0.13
Natural gas – AECO C$0.10/mcf [2]				
Excluding financial derivatives	$ 42	$ 0.08	$ 29	$ 0.05
Including financial derivatives	$ 23 - 33	$ 0.04 - 0.06	$ 16 - 23	$ 0.03 - 0.04
Volume changes				
Crude oil – 10,000 bbl/d	$ 107	$ 0.20	$ 52	$ 0.10
Natural gas – 10 mmcf/d	$ 20	$ 0.04	$ 9	$ 0.02
Foreign currency rate change				
$0.01 change in US$ [2]				
Including financial derivatives	$ 83 - 85	$ 0.15 - 0.16	$ 28 - 29	$ 0.05
Interest rate change - 1%	$ 38	$ 0.07	$ 38	$ 0.07

(1) The sensitivities are calculated based on 2007 second quarter results and exclude mark-to-market gains (losses) on risk management activities.

(2) 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

($/boe) [1]	Three Months Ended **Jun 30 2007**	 Mar 31 2007	 Jun 30 2006	Six Months Ended **Jun 30 2007**	 Jun 30 2006
Sales price [2]	**$ 49.70**	$ 49.32	$ 50.36	**$ 49.50**	$ 48.39
Royalties	**5.99**	6.76	5.80	**6.37**	6.11
Production expense [3]	**10.44**	10.10	8.85	**10.27**	8.66
Netback	**33.27**	32.46	35.71	**32.86**	33.62
Midstream contribution [3]	**(0.20)**	(0.24)	(0.23)	**(0.22)**	(0.24)
Administration	**0.96**	1.08	0.78	**1.02**	0.81
Interest, net	**1.40**	1.49	0.53	**1.44**	0.52
Realized risk management loss (gain)	**1.66**	(1.58)	7.81	**0.04**	7.85
Realized foreign exchange loss	**0.47**	0.10	0.25	**0.28**	0.07
Taxes other than income tax - current	**0.16**	1.18	1.13	**0.67**	0.93
Current income tax - North America	**0.21**	0.45	0.42	**0.33**	0.39
Current income tax - North Sea	**0.99**	0.62	(0.01)	**0.81**	-
Current income tax - Offshore West Africa	**0.29**	0.18	0.30	**0.23**	0.29
Cash flow	**$ 27.33**	$ 29.18	$ 24.73	**$ 28.26**	$ 23.00

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

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

(3) Excluding intersegment elimination.

FINANCIAL STATEMENTS

Consolidated balance sheets

(millions of Canadian dollars, unaudited)	**Jun 30 2007**	Dec 31 2006
ASSETS		
Current assets		
Cash and cash equivalents	**$ 11**	$ 23
Accounts receivable and other	**1,737**	1,947
Future income tax	**190**	163
Current portion of other long-term assets (note 3)	**36**	106
	1,974	2,239
Property, plant and equipment (note 12)	**32,601**	30,767
Other long-term assets (note 3)	**56**	154
	$ 34,631	$ 33,160
LIABILITIES		
Current liabilities		
Accounts payable	**$ 547**	$ 842
Accrued liabilities	**1,685**	1,618
Current portion of other long-term liabilities (note 5)	**602**	611
	2,834	3,071
Long-term debt (note 4)	**10,958**	11,043
Other long-term liabilities (note 5)	**1,747**	1,393
Future income tax	**7,212**	6,963
	22,751	22,470
SHAREHOLDERS' EQUITY		
Share capital (note 7)	**2,649**	2,562
Retained earnings	**9,169**	8,141
Accumulated other comprehensive income (loss) (note 8)	**62**	(13)
	11,880	10,690
	$ 34,631	$ 33,160

Commitments (note 11)

Consolidated statements of earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended **Jun 30 2007**	 Jun 30 2006	Six Months Ended **Jun 30 2007**	 Jun 30 2006
Revenue	**$ 3,152**	$ 3,041	**$ 6,270**	$ 5,709
Less: royalties	**(331)**	(302)	**(707)**	(618)
Revenue, net of royalties	**2,821**	2,739	**5,563**	5,091
Expenses				
Production	**584**	467	**1,149**	886
Transportation and blending	**385**	402	**744**	779
Depletion, depreciation and amortization	**720**	557	**1,429**	1,078
Asset retirement obligation accretion (note 5)	**17**	16	**35**	33
Administration	**53**	40	**113**	82
Stock-based compensation expense (recovery) (note 5)	**106**	(34)	**131**	98
Interest, net	**77**	28	**160**	53
Risk management activities (note 10)	**35**	381	**483**	777
Foreign exchange gain	**(224)**	(46)	**(251)**	(41)
	1,753	1,811	**3,993**	3,745
Earnings before taxes	**1,068**	928	**1,570**	1,346
Taxes other than income tax	**29**	77	**92**	138
Current income tax expense (note 6)	**82**	37	**152**	69
Future income tax expense (recovery) (note 6)	**116**	(224)	**216**	44
Net earnings	**$ 841**	$ 1,038	**$ 1,110**	$ 1,095
Net earnings per common share (note 9)				
Basic and diluted	**$ 1.56**	$ 1.93	**$ 2.06**	$ 2.04

Consolidated statements of shareholders' equity

(millions of Canadian dollars, unaudited)	Six Months Ended Jun 30 2007	Jun 30 2006
Common shares		
Balance – beginning of period	**$ 2,562**	$ 2,442
Issued upon exercise of stock options	**16**	13
Previously recognized liability on stock options exercised for common shares	**71**	63
Purchase of common shares under Normal Course Issuer Bid	**-**	(2)
Balance – end of period	**2,649**	2,516
Retained earnings		
Balance – beginning of period, as originally reported	**8,141**	5,804
Transition adjustment on adoption of financial instruments standards (note 2)	**10**	-
Balance – beginning of period, as restated	**8,151**	5,804
Net earnings	**1,110**	1,095
Dividends on common shares (note 7)	**(92)**	(81)
Purchase of common shares under Normal Course Issuer Bid	**-**	(20)
Balance – end of period	**9,169**	6,798
Accumulated other comprehensive income (loss) (note 2)		
Balance – beginning of period	**(13)**	(9)
Transition adjustment on adoption of financial instruments standards	**159**	-
Balance – beginning of period, after effect of transition adjustment	**146**	(9)
Other comprehensive loss, net of taxes	**(84)**	(3)
Balance – end of period	**62**	(12)
Shareholders' equity	**$ 11,880**	$ 9,302

Consolidated statements of comprehensive income

(millions of Canadian dollars, unaudited)	Three Months Ended Jun 30 2007	Jun 30 2006	Six Months Ended Jun 30 2007	Jun 30 2006
Net earnings	**$ 841**	$ 1,038	**$ 1,110**	$ 1,095
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income (loss) during the period (net of taxes of $47 million – three months ended; $8 million – six months ended)	**112**	-	**(4)**	-
Reclassification to net earnings (net of taxes of $nil – three months ended; $35 million – six months ended)	**(1)**	-	**(75)**	-
	111	-	**(79)**	-
Foreign currency translation adjustment				
Translation of net investment	**(4)**	(4)	**(5)**	(6)
Hedge of net investment, net of tax	**-**	3	**-**	3
	(4)	(1)	**(5)**	(3)
Other comprehensive income (loss), net of taxes	**107**	(1)	**(84)**	(3)
Comprehensive income	**$ 948**	$ 1,037	**$ 1,026**	$ 1,092

Consolidated statements of cash flows

(millions of Canadian dollars, unaudited)	Three Months Ended Jun 30 2007	Three Months Ended Jun 30 2006	Six Months Ended Jun 30 2007	Six Months Ended Jun 30 2006
Operating activities				
Net earnings	**$ 841**	$ 1,038	**$ 1,110**	$ 1,095
Non-cash items				
Depletion, depreciation and amortization	**720**	557	**1,429**	1,078
Asset retirement obligation accretion	**17**	16	**35**	33
Stock-based compensation expense (recovery)	**106**	(34)	**131**	98
Unrealized risk management activities	**(57)**	(26)	**479**	(18)
Unrealized foreign exchange gain	**(250)**	(58)	**(282)**	(48)
Deferred petroleum revenue tax	**20**	18	**17**	44
Future income tax expense (recovery)	**116**	(224)	**216**	44
Deferred charges	**8**	7	**(5)**	(8)
Abandonment expenditures	**(13)**	(17)	**(33)**	(32)
Net change in non-cash working capital	**131**	(47)	**12**	(358)
	1,639	1,230	**3,109**	1,928
Financing activities				
Issue (repayment) of bankers' acceptances	**167**	781	**(1,846)**	1,400
(Repayment) issue of medium-term notes	**-**	-	**(125)**	400
Repayment of senior unsecured notes	**(33)**	-	**(33)**	-
Issue of US dollar debt securities	**-**	-	**2,553**	-
Issue of common shares on exercise of stock options	**3**	3	**16**	13
Dividends on common shares	**(46)**	(40)	**(86)**	(72)
Purchase of common shares	**-**	(22)	**-**	(22)
Net change in non-cash working capital	**45**	4	**23**	6
	136	726	**502**	1,725
Investing activities				
Expenditures on property, plant and equipment	**(1,447)**	(1,543)	**(3,440)**	(3,837)
Net proceeds on sale of property, plant and equipment	**-**	2	**4**	2
Net expenditures on property, plant and equipment	**(1,447)**	(1,541)	**(3,436)**	(3,835)
Net change in non-cash working capital	**(331)**	(412)	**(187)**	179
	(1,778)	(1,953)	**(3,623)**	(3,656)
(Decrease) increase in cash and cash equivalents	**(3)**	3	**(12)**	(3)
Cash and cash equivalents – beginning of period	**14**	12	**23**	18
Cash and cash equivalents – end of period	**$ 11**	$ 15	**$ 11**	$ 15
Interest paid	**$ 87**	$ 57	**$ 245**	$ 109
Taxes paid				
Taxes other than income tax	**$ 39**	$ 52	**$ 74**	$ 133
Current income tax	**$ 1**	$ 80	**$ 72**	$ 253

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

1. ACCOUNTING POLICIES

The interim consolidated financial statements of Canadian Natural Resources Limited (the "Company") include the Company and all of its subsidiaries and partnerships, and have been prepared following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2006, except as described in note 2. The interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2006.

Comparative figures

Certain figures relating to the presentation of gross revenues and gross transportation and blending provided for the prior year have been reclassified to conform to the presentation adopted in the fourth quarter of 2006.

2. CHANGE IN ACCOUNTING POLICY

Financial Instruments and Comprehensive Income

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

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

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

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

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

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

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

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

Risk Management Activities

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

All derivative financial instruments are recognized at estimated fair value on the consolidated balance sheet at each balance sheet date. The estimated fair value of derivative instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. However, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

The Company formally documents all derivative financial instruments designated as hedging transactions at the inception of the hedging relationship, in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated, both at inception of the hedge and on an ongoing basis.

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

The Company enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. Changes in the fair value of interest rate swap contracts designated as fair value hedges and corresponding changes in the fair value of the hedged long-term debt are included in interest expense in consolidated net earnings. Changes in the fair value of non-designated interest rate swap contracts are included in risk management activities in consolidated net earnings.

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

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

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

Comprehensive Income

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

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

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

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

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

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

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

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

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

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

3. OTHER LONG–TERM ASSETS

		Jun 30 2007		Dec 31 2006
Deferred charges (note 2)	**$**	**70**	$	109
Risk management (note 10)		**-**		128
Other		**22**		23
		92		260
Less: current portion		**36**		106
	$	**56**	$	154

4. LONG–TERM DEBT

	Jun 30 2007	Dec 31 2006
Canadian dollar denominated debt		
Bank credit facilities (bankers' acceptances)	**$ 4,775**	$ 6,621
Medium-term notes	**800**	925
	5,575	7,546
US dollar denominated debt		
Senior unsecured notes (2007 – US$62 million; and 2006 - US$93 million)	**66**	108
US dollar debt securities (2007 - US$5,108 million; and 2006 - US$2,908 million)	**5,432**	3,389
Less – original issue discount on senior unsecured notes and US dollar debt securities (1)	**(23)**	-
	5,475	3,497
Change in fair value of interest rate swaps on US dollar debt securities (2)	**(39)**	-
	5,436	3,497
Long-term debt before transaction costs	**11,011**	11,043
Less – transaction costs (1) (3)	**(53)**	-
	$ 10,958	$ 11,043

(1) As described in note 2, effective January 1, 2007, the Company has included unamortized original issue discounts and directly attributable transaction costs in the carrying value of the outstanding debt.

(2) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $39 million to reflect the fair value impact of hedge accounting (note 2).

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

Bank credit facilities

As at June 30, 2007, the Company had in place unsecured bank credit facilities of $6,212 million, comprised of:

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

During the second quarter of 2007, one of the 5-year revolving syndicated credit facilities was increased to $2,230 million and the $500 million demand credit facility was terminated. The revolving syndicated credit facilities were extended and now mature June 2012. Both facilities are extendible annually for one year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date.

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

The weighted average interest rate of the bank credit facilities outstanding at June 30, 2007, was 4.8% (December 31, 2006 - 4.8%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $345 million, including $300 million related to the Horizon Oil Sands Project (“Horizon Project”), were outstanding at June 30, 2007.

Medium-term notes

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

The Company has $1,600 million remaining on its $2,000 million shelf prospectus filed in August 2005 that allows for the issue of medium-term notes in Canada until September 2007. If issued, these securities will bear interest as determined at the date of issuance.

Senior unsecured notes

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

US dollar debt securities

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

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

5. OTHER LONG–TERM LIABILITIES

	Jun 30 2007	Dec 31 2006
Asset retirement obligations	**$ 1,128**	$ 1,166
Stock-based compensation	**622**	744
Risk management (note 10)	**495**	-
Other	**104**	94
	2,349	2,004
Less: current portion	**602**	611
	$ 1,747	$ 1,393

Asset retirement obligations

At June 30, 2007, the Company's total estimated cost to settle its asset retirement obligations was approximately $4,438 million (December 31, 2006 - $4,497 million). These costs will be incurred over the lives of the operating assets and have been discounted using an average credit-adjusted risk free rate of 6.7%. A reconciliation of the discounted asset retirement obligations is as follows:

	Six Months Ended Jun 30, 2007	Year Ended Dec 31, 2006
Balance – beginning of period	**$ 1,166**	$ 1,112
Liabilities incurred	**8**	26
Liabilities acquired	**-**	56
Liabilities settled	**(33)**	(75)
Asset retirement obligation accretion	**35**	68
Revision of estimates	**1**	(21)
Foreign exchange	**(49)**	-
Balance – end of period	**$ 1,128**	$ 1,166

Stock-based compensation

The Company recognizes a liability for the potential cash settlements under its Stock Option Plan. The current portion represents the maximum amount of the liability payable within the next 12-month period if all vested options are surrendered for cash settlement.

	Six Months Ended Jun 30, 2007	Year Ended Dec 31, 2006
Balance – beginning of period	**$ 744**	$ 891
Stock-based compensation	**131**	139
Payments for options surrendered	**(221)**	(264)
Transferred to common shares	**(71)**	(101)
Capitalized to Horizon Project	**39**	79
Balance – end of period	**622**	744
Less: current portion of stock-based compensation	**453**	611
	$ 169	$ 133

6. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Six Months Ended	
	Jun 30 2007	Jun 30 2006	**Jun 30 2007**	Jun 30 2006
Current income tax – North America	**$ 12**	$ 22	**$ 37**	$ 40
Current income tax – North Sea	**54**	(1)	**89**	-
Current income tax – Offshore West Africa	**16**	16	**26**	29
Current income tax expense	**82**	37	**152**	69
Future income tax expense (recovery)	**116**	(224)	**216**	44
Income tax expense (recovery)	**$ 198**	$ (187)	**$ 368**	$ 113

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 and amount of capital expenditures incurred in Canada in any particular year.

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

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

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

7. SHARE CAPITAL

	Six Months Ended Jun 30, 2007	
Issued **Common shares**	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**537,903**	**$ 2,562**
Issued upon exercise of stock options	**1,482**	**16**
Previously recognized liability on stock options exercised for common shares	**-**	**71**
Balance – end of period	**539,385**	**$ 2,649**

Normal Course Issuer Bid

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

Dividend policy

In March 2007, the Board of Directors set the regular quarterly dividend at $0.085 per common share. The Company has paid regular quarterly dividends in January, April, July, and October of each year since 2001. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

Stock options

	Six Months Ended Jun 30, 2007	
	Stock options (thousands)	**Weighted average exercise price**
Outstanding – beginning of period	**34,425**	**$ 33.77**
Granted	**801**	**$ 64.58**
Exercised for common shares	**(1,482)**	**$ 10.84**
Surrendered for cash settlement	**(4,543)**	**$ 15.21**
Forfeited	**(1,433)**	**$ 44.95**
Outstanding – end of period	**27,768**	**$ 38.39**
Exercisable – end of period	**7,842**	**$ 22.33**

8. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

	Jun 30 2007	Jun 30 2006
Derivative financial instruments designated as cash flow hedges	**$ 80**	$ -
Foreign currency translation adjustment	**(18)**	(12)
Accumulated other comprehensive income (loss)	**$ 62**	$ (12)

9. NET EARNINGS PER COMMON SHARE

			Six Months Ended	
	Jun 30 2007	Jun 30 2006	**Jun 30 2007**	Jun 30 2006
Weighted average common shares outstanding (thousands) – basic and diluted	**539,296**	537,351	**539,094**	537,188
Net earnings – basic and diluted	**$ 841**	$ 1,038	**$ 1,110**	$ 1,095
Net earnings per common share – basic and diluted	**$ 1.56**	$ 1.93	**$ 2.06**	$ 2.04

10. FINANCIAL INSTRUMENTS

Risk management

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

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

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

	Six Months Ended Jun 30, 2007	Year Ended Dec 31, 2006	
Asset (liability)	**Risk management mark-to-market**	Risk management mark-to-market	Deferred revenue
Balance – beginning of period	**$ 128**	$ (877)	$ (8)
Retained earnings effect of adoption of financial instrument standards (note 2)	**14**	-	-
Net cost of outstanding put options	**215**	455	-
Net change in fair value of outstanding derivative financial instruments attributable to:			
- Risk management activities	**(479)**	995	-
- Interest expense	**(39)**	-	-
- Foreign exchange	**(207)**	10	-
- Other comprehensive income	**112**	-	-
Amortization of deferred revenue	**-**	-	8
	(256)	583	-
Add: Put premium financing obligations (1)	**(239)**	(455)	-
Balance – end of period	**(495)**	128	-
Less: current portion	**(149)**	88	-
	$ (346)	$ 40	$ -

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

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

	Three Months Ended		Six Months Ended	
	Jun 30 2007	Jun 30 2006	**Jun 30 2007**	Jun 30 2006
Net realized risk management loss	**$ 92**	$ 407	**$ 4**	$ 795
Net unrealized risk management mark-to-market (gain) loss	**(57)**	(26)	**479**	(18)
	$ 35	$ 381	**$ 483**	$ 777

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

	Remaining term			Volume	Average price			Index
Crude oil								
Crude oil price collars	Jul 2007	–	Dec 2007	15,000 bbl/d	US$50.00	–	US$66.25	Mayan Heavy
	Jul 2007	–	Dec 2007	50,000 bbl/d	US$60.00	–	US$71.49	WTI
	Jul 2007	–	Dec 2007	100,000 bbl/d	US$60.00	–	US$78.11	WTI
	Jul 2007	–	Dec 2007	50,000 bbl/d	US$65.00	–	US$84.52	WTI
	Jan 2008	–	Mar 2008	50,000 bbl/d	US$60.00	–	US$80.06	WTI
	Jan 2008	–	Dec 2008	20,000 bbl/d	US$50.00	–	US$65.53	Mayan Heavy
	Jan 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$75.22	WTI
	Jan 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.05	WTI
	Jan 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.98	WTI
Crude oil puts	Jul 2007	–	Dec 2007	100,000 bbl/d			US$45.00	WTI
	Jul 2007	–	Dec 2007	77,000 bbl/d			US$60.00	WTI
	Jan 2008	–	Dec 2008	50,000 bbl/d			US$55.00	WTI
Brent differential swaps	Jul 2007	–	Dec 2007	50,000 bbl/d			US$1.34	WTI/Dated Brent

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

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

	Remaining term			Volume	Average price			Index
Natural gas								
AECO collars	Jul 2007	–	Dec 2007	60,000 GJ/d	C$8.00	–	C$8.79	AECO
	Jul 2007	–	Oct 2007	500,000 GJ/d	C$6.00	–	C$10.13	AECO
	Jul 2007	–	Oct 2007	500,000 GJ/d	C$7.00	–	C$8.24	AECO
	Nov 2007	–	Mar 2008	400,000 GJ/d	C$7.00	–	C$14.08	AECO
	Nov 2007	–	Mar 2008	500,000 GJ/d	C$7.50	–	C$10.81	AECO

The Company’s outstanding commodity financial derivatives will be settled monthly based on the applicable index pricing for the respective contract month.

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

	Remaining term	Amount ($ millions)	Fixed rate	Floating rate
Interest rate				
Swaps – fixed to floating	Jul 2007 – Oct 2012	US$350	5.45%	LIBOR [1] + 0.81%
	Jul 2007 – Dec 2014	US$350	4.90%	LIBOR [1] + 0.38%

(1) London Interbank Offered Rate

	Remaining term	Amount ($ millions)	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency					
Swaps	Jul 2007 – Aug 2016	US$250	1.116	6.00%	5.40%
	Jul 2007 – May 2017	US$1,100	1.170	5.70%	5.10%
	Jul 2007 – Mar 2038	US$550	1.170	6.25%	5.76%

11. COMMITMENTS

The Company has committed to certain payments as follows:

	Remaining 2007	2008	2009	2010	2011	Thereafter
Product transportation and pipeline [1]	$ 133	$ 217	$ 147	$ 135	$ 105	$ 1,055
Offshore equipment operating leases [2]	$ 195	$ 48	$ 48	$ 48	$ 46	$ 108
Offshore drilling [3] [4]	$ 187	$ 168	$ 50	$ 50	$ 48	$ 162
Asset retirement obligations [5]	$ 2	$ 3	$ 3	$ 4	$ 4	$ 4,422
Office leases	$ 15	$ 31	$ 31	$ 32	$ 22	$ -
Electricity and other	$ 89	$ 158	$ 165	$ 18	$ 1	$ -

(1) The Company entered into a 25-year pipeline transportation agreement commencing in 2008, related to future crude oil production. The agreement is renewable for successive 10-year periods at the Company's option. During the initial term, the annual toll payments before operating costs will be approximately $35 million.

(2) Offshore equipment operating leases are primarily comprised of obligations related to floating production, storage and offtake vessels ("FPSO"). During 2006, the Company entered into an agreement to lease an additional FPSO commencing in 2008, in connection with the planned offshore development in Gabon, Offshore West Africa. The new FPSO lease agreement contains cancellation provisions at the option of the Company, subject to escalating termination payments throughout 2007 to a maximum of US$395 million. As at June 30, 2007, US$140 million of potential termination payments have been included as a 2007 commitment in this table.

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

(4) 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. In addition to incurred construction costs, the wellhead towers agreement contains cancellation provisions at the option of the Company, subject to varying termination payments based on pro-rata percentages of the contract price throughout June 2009, subject to a maximum of US$95 million. The drilling rig agreement contains cancellation provisions at the option of the Company, subject to escalating termination payments to a maximum of US$55 million in 2008. As at June 30, 2007, US$120 million of potential cancellation and termination payments have been included as a 2007 commitment in this table.

(5) Amounts represent management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2007 – 2011 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

In 2005, the Board of Directors of the Company approved the construction costs for Phase 1 of the Horizon Project, with an approved budget of $6.8 billion. Cumulative construction spending to June 30, 2007 was approximately $5.4 billion. Final construction costs for Phase 1 are expected to exceed the approved budget.

12. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America				North Sea				Offshore West Africa			
	Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30	
	2007	2006	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006
Segmented revenue	**2,584**	2,406	**5,119**	4,522	**402**	377	**833**	697	**161**	255	**305**	482
Less: royalties	**(315)**	(295)	**(681)**	(605)	**-**	-	**(1)**	(1)	**(16)**	(7)	**(25)**	(12)
Segmented revenue, net of royalties	**2,269**	2,111	**4,438**	3,917	**402**	377	**832**	696	**145**	248	**280**	470
Segmented expenses												
Production	**442**	356	**864**	668	**120**	87	**236**	168	**18**	19	**40**	41
Transportation and blending	**391**	407	**756**	791	**4**	5	**8**	8	**-**	-	**-**	-
Depletion, depreciation and amortization	**595**	448	**1,155**	863	**87**	62	**194**	122	**36**	45	**76**	89
Asset retirement obligation accretion	**10**	9	**19**	17	**7**	7	**15**	15	**-**	-	**1**	1
Realized risk management activities	**67**	316	**(25)**	633	**25**	91	**29**	162	**-**	-	**-**	-
Total segmented expenses	**1,505**	1,536	**2,769**	2,972	**243**	252	**482**	475	**54**	64	**117**	131
Segmented earnings (loss) before the following	**764**	575	**1,669**	945	**159**	125	**350**	221	**91**	184	**163**	339
Non-segmented expenses												
Administration												
Stock-based compensation expense (recovery)												
Interest, net												
Unrealized risk management activities												
Foreign exchange gain												
Total non-segmented expenses												
Earnings before taxes												
Taxes other than income tax												
Current income tax expense												
Future income tax expense (recovery)												
Net earnings												

(millions of Canadian dollars, unaudited)	Midstream Three Months Ended Jun 30		Six Months Ended Jun 30		Inter-segment elimination and other Three Months Ended Jun 30		Six Months Ended Jun 30		Total Three Months Ended Jun 30		Six Months Ended Jun 30	
	2007	2006	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006
Segmented revenue	**17**	17	**36**	35	**(12)**	(14)	**(23)**	(27)	**3,152**	3,041	**6,270**	5,709
Less: royalties	**-**	-	**-**	-	**-**	-	**-**	-	**(331)**	(302)	**(707)**	(618)
Segmented revenue, net of royalties	**17**	17	**36**	35	**(12)**	(14)	**(23)**	(27)	**2,821**	2,739	**5,563**	5,091
Segmented expenses												
Production	**5**	6	**11**	11	**(1)**	(1)	**(2)**	(2)	**584**	467	**1,149**	886
Transportation and blending	**-**	-	**-**	-	**(10)**	(10)	**(20)**	(20)	**385**	402	**744**	779
Depletion, depreciation and amortization	**2**	2	**4**	4	**-**	-	**-**	-	**720**	557	**1,429**	1,078
Asset retirement obligation accretion	**-**	-	**-**	-	**-**	-	**-**	-	**17**	16	**35**	33
Realized risk management activities	**-**	-	**-**	-	**-**	-	**-**	-	**92**	407	**4**	795
Total segmented expenses	**7**	8	**15**	15	**(11)**	(11)	**(22)**	(22)	**1,798**	1,849	**3,361**	3,571
Segmented earnings (loss) before the following	**10**	9	**21**	20	**(1)**	(3)	**(1)**	(5)	**1,023**	890	**2,202**	1,520
Non-segmented expenses												
Administration									**53**	40	**113**	82
Stock-based compensation expense (recovery)									**106**	(34)	**131**	98
Interest, net									**77**	28	**160**	53
Unrealized risk management activities									**(57)**	(26)	**479**	(18)
Foreign exchange gain									**(224)**	(46)	**(251)**	(41)
Total non-segmented expenses									**(45)**	(38)	**632**	174
Earnings before taxes									**1,068**	928	**1,570**	1,346
Taxes other than income tax									**29**	77	**92**	138
Current income tax expense									**82**	37	**152**	69
Future income tax expense (recovery)									**116**	(224)	**216**	44
Net earnings									**841**	1,038	**1,110**	1,095

Net additions to property, plant and equipment

	Six Months Ended					
	Jun 30, 2007			Jun 30, 2006		
	Net Cash Expenditures	**Non-Cash/ Fair Value Changes (1)**	**Capitalized Costs**	Net Cash Expenditures	Non-Cash/ Fair Value Changes (1)	Capitalized Costs
North America	**$ 1,417**	**$ 8**	**$ 1,425**	$ 1,973	$ 5	$ 1,978
North Sea	**274**	**-**	**274**	287	-	287
Offshore West Africa	**82**	**-**	**82**	77	-	77
Other	**2**	**-**	**2**	9	-	9
Horizon Project (2)	**1,650**	**-**	**1,650**	1,468	-	1,468
Midstream	**2**	**-**	**2**	9	-	9
Head office	**9**	**-**	**9**	12	-	12
	$ 3,436	**$ 8**	**$ 3,444**	$ 3,835	$ 5	$ 3,840

(1) Asset retirement obligations, future income tax adjustments on non-tax base assets, and other fair value adjustments.

(2) Cash expenditures for the Horizon Project also include capitalized interest and stock-based compensation.

	Property, plant and equipment		Total assets	
	Jun 30 2007	Dec 31 2006	**Jun 30 2007**	Dec 31 2006
Segmented assets				
North America	**$ 22,166**	$ 21,879	**$ 23,637**	$ 23,670
North Sea	**1,939**	2,029	**2,150**	2,248
Offshore West Africa	**1,194**	1,204	**1,304**	1,323
Other	**26**	24	**49**	46
Horizon Project	**7,000**	5,350	**7,106**	5,444
Midstream	**205**	207	**314**	355
Head office	**71**	74	**71**	74
	$ 32,601	$ 30,767	**$ 34,631**	$ 33,160

Capitalized interest

The Company capitalizes construction period interest based on Horizon Project costs incurred and the Company's cost of borrowing. Interest capitalization on Phase 1 will cease once construction is substantially complete and this phase of the Horizon Project is available for its intended use. For the six months ended June 30, 2007, pre-tax interest of $152 million was capitalized to the Horizon Project (June 30, 2006 - $74 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 August 2005. 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 June 30, 2007:

Interest coverage (times)	
Net earnings (1)	7.5x
Cash flow from operations (2)	12.1x

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

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

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time on Thursday, August 2, 2007. The North American conference call number is 1-866-898-9626 and the outside North American conference call number is 001-416-340-2216. Please call in about 10 minutes before the starting time in order to be patched into the call. The conference call will also be broadcast live on the internet and may be accessed through the Canadian Natural website at www.cnrl.com.

A taped rebroadcast will be available until 6:00 p.m. Mountain Time Thursday, August 9, 2007. To access the postview in North America, dial 1-800-408-3053. Those outside of North America, dial 001-416-695-5800. The passcode to use is 3223400.

WEBCAST

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

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

2007 THIRD QUARTER RESULTS

2007 third quarter results are scheduled for release on Thursday, November 1, 2007. A conference call will be held on that day at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time.

For further information, please contact:

CANADIAN NATURAL RESOURCES LIMITED
2500, 855 - 2nd Street S.W.
Calgary, Alberta
T2P 4J8

Telephone: (403) 514-7777
Facsimile: (403) 514-7888
Email: ir@cnrl.com
Website: www.cnrl.com

Trading Symbol - CNQ
Toronto Stock Exchange
New York Stock Exchange

ALLAN P. MARKIN
Chairman

JOHN G. LANGILLE
Vice-Chairman

STEVE W. LAUT
President &
Chief Operating Officer

DOUGLAS A. PROLL
Chief Financial Officer &
Senior Vice-President, Finance

COREY B. BIEBER
Vice-President,
Finance & Investor Relations