CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES RECORD QUARTERLY PRODUCTION AND STRONG QUARTERLY CASH FLOW

In commenting on second quarter 2006 results, Canadian Natural's Chairman, Allan Markin stated, "It was another record quarter for Canadian Natural as we continue to execute our defined plan for profitable growth. We achieved record quarterly production results from our North America operations for both crude oil and natural gas. Internationally, the West Espoir development came on stream last week from the initial production well. The Field will continue to ramp towards targeted peak production of 13,000 barrels of oil equivalent per day in early 2007. Our record production levels reflect the performance of our natural gas drilling program and the work of our project teams in our crude oil areas. At our Horizon Oil Sands Project, we remain slightly ahead of schedule and continue to track to budget targets due to maintaining focus on execution. This has been helped in large part by the significant amount of front end engineering that was completed prior to project sanction. Our people and contractors are finding new and innovative ways of doing things, which will help us to deliver this world class project."

John Langille, Vice-Chairman, commented "Seasonably low heavy crude oil differentials combined with the impact of the reversal of certain pipelines to the US Gulf Coast helped deliver record realized wellhead heavy crude oil pricing during the second quarter. This heavy crude oil pricing helped deliver strong cash flow for the quarter and six month period. This strong cash flow, combined with the continued management of our capital costs means that we still expect to exit 2006 with an exceptionally strong balance sheet, with debt to cash flow targeted under 1.2 times and debt to book capitalization targeted below the current level of 35% despite the expenditure of $2.7 billion on Horizon."

Canadian Natural's President and Chief Operating Officer, Steve Laut, in commenting on the Company's quarter end stated, "Canadian Natural's asset base is strong, delivering another quarter of record production and 10% year over year production growth. We continue to maintain control of our costs in this highly inflationary environment and continue to execute our strategy to optimize capital allocation and maximize value. In Q2/06 we reallocated capital from natural gas to crude oil, and in the second half of 2006 we will continue this trend by deferring an additional 308 natural gas wells as we effectively manage our portfolio. Canadian Natural's ability to allocate capital to maximize value, while maintaining focus on our large projects at Horizon, Primrose and Offshore West Africa, reflect the strength of our assets, our operating philosophy and the dedication of our people."

HIGHLIGHTS

($ millions, except as noted)	Quarterly Results Q2/06	Q1/06	Q2/05	Six Month Results 2006	2005
Net earnings (loss)	**$ 1,038**	$ 57	$ 219	**$ 1,095**	$ (205)
per common share, basic	**$ 1.93**	$ 0.11	$ 0.41	**$ 2.04**	$ (0.38)
Adjusted net earnings from operations(1)	**$ 514**	$ 268	$ 460	**$ 782**	$ 840
per common share, basic	**$ 0.96**	$ 0.50	$ 0.86	**$ 1.46**	$ 1.57
Cash flow from operations(2)	**$ 1,287**	$ 1,039	$ 1,136	**$ 2,326**	$ 2,145
per common share, basic	**$ 2.40**	$ 1.93	$ 2.12	**$ 4.33**	$ 4.00
Capital expenditures, net of dispositions	**$ 1,558**	$ 2,309	$ 609	**$ 3,867**	$ 1,981
Debt to book capitalization(3)	**35%**	34%	35%	**35%**	35%
Daily production, before royalties					
Natural gas (mmcf/d)	**1,475**	1,436	1,454	**1,456**	1,455
Crude oil and NGLs (bbl/d)	**338,852**	323,662	289,064	**331,299**	288,437
Equivalent production (boe/d)	**584,611**	563,027	531,380	**573,879**	530,851

(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 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 its ability to fund capital reinvestment and debt repayment. The derivation of this item is discussed in the MD&A.

(3) Includes current portion of long-term debt.

- Quarterly cash flow of $1,287 million, a 13% increase over Q2/05 and 24% increase over Q1/06, is due to higher sales revenues, primarily from the Primrose thermal heavy oil operations combined with better heavy oil price realizations. Sales revenues were reduced by inventoried international production that was produced but not sold by quarter end, which would have added approximately $60 million of cash flow from operations in Q2/06.
- Quarterly net earnings of $1,038 million, representing a 374% increase over Q2/05 and an 18-fold increase over Q1/06. Q2/06 net earnings included a benefit of $438 million for the effect of statutory income tax rate changes in Canada on future income tax liabilities.
- Strong quarterly adjusted net earnings from operations of $514 million, 12% higher than Q2/05 results and a 92% increase over Q1/06.
- Strong balance sheet with debt to book capitalization at 35% and debt to EBITDA at 0.9x.
- Quarterly production volumes 10% higher than Q2/05 and 4% higher than Q1/06.
- Crude oil volumes increased 17% from Q2/05 and 5% from Q1/06 levels as a result of increased production from heavy crude oil operations at Primrose and Pelican Lake.
- Record North America natural gas production in Q2/06 represented an increase of 1% over Q2/05 and 3% from Q1/06 reflecting the impact of the 2006 winter drilling program.
- Completed a Q2/06 drilling program of 129 net wells, excluding stratigraphic test and service wells, with a 95% success ratio, reflecting Canadian Natural's strong, predictable, low-risk asset base.
- Maintained strong undeveloped conventional land base in Canada of 11.0 million net acres - a key asset in today's highly competitive industry.

- The Horizon Oil Sands Project (“Horizon Project”), continues to track to budget targets and slightly ahead of schedule, with site preparation and construction work benefiting from the use of off-site modularization and better than forecast labour productivity.

- Continued production improvements at Pelican Lake Field arising from new drilling activity and expansion of enhanced crude oil recovery strategies. Pelican Lake crude oil production averaged approximately 30,000 bbl/d during the quarter, up 48% or approximately 10,000 bbl/d from Q2/05 and up approximately 1,000 bbl/d from Q1/06 primarily as a result of the success of the commercial water flood project.

- At Primrose, new production pads from the Primrose North steam facility reached peak production rates of 30,000 bbl/d and as a result production is currently in excess of 70,000 bbl/d.

- Mobilized the drilling rig to West Espoir and are currently undertaking a 10 well drilling program, which saw initial production at the end of July at gross field rates of 3,800 bbl/d of light crude oil on the first well with eventual peak net Field production of approximately 13,000 boe/d in early 2007.

- At Baobab four production wells are experiencing increased sand and solids production and have been curtailed, reducing production by approximately 12,000 bbl/d. Remediation initiatives to increase sand handling capacity on the Floating Production Storage and Offtake (“FPSO”) vessel and other possible solutions are being evaluated. No impact on recoverable reserves are expected from these developments.

- In the tender phase for key contracts and equipment for the Olowi Field development offshore Gabon, which is targeting first production in late 2008.

- As part of the Company’s ongoing commodity hedging program to reduce the risk of volatility in commodity price markets and to support the Company’s cash flow for its capital expenditure program throughout the Horizon Project construction period, approximately 25% of estimated 2007 crude oil volumes, and approximately 60% of estimated 2007 natural gas volumes, have been hedged.

- Repurchased 390,000 common shares under its Normal Course Issuer Bid during Q2/06.

- Declared a quarterly dividend at $0.075 per common share for the July 1, 2006 dividend payment.

CORPORATE UPDATE

Canadian Natural is pleased to announce the appointments of the Honourable Frank J. McKenna, P.C., O.N.B., Q.C. and Steve W. Laut to the Board of Directors of the Company effective August 1, 2006.

Mr. McKenna is the former Canadian Ambassador to the United States of America and former Premier of the Province of New Brunswick. He is currently Deputy Chair of TD Bank Financial Group.

Mr. Laut is the President and Chief Operating Officer of the Company. He first joined the Company in 1991 and was appointed its President and Chief Operating Officer in 2005.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

In order to facilitate efficient operations, Canadian Natural focuses its activities into 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.

As a result of strong crude oil prices including record heavy oil prices, combined with softer natural gas pricing, the Company has shifted a portion of its second half drilling program from natural gas drilling to higher return crude oil drilling. To this end, natural gas drilling activities for 2006 will be reduced by 308 wells or approximately 50% of original 2006 second half budget. No changes will be made to the natural gas program where competitive drainage or lease expiries could impact development. Additionally, those wells considered as set-up for 2007 activities will continue unabated. Approximately 211 wells cut from the natural gas program are low rate coal bed methane or shallow natural gas locations. No changes to the long term natural gas plans of the Company are contemplated. The natural gas program, currently also impeded by commodity price uncertainty, is subject to significant cost inflation due to higher demand for drilling and related completion services.

In contrast, the crude oil program utilizes less third party services and is currently experiencing record wellhead pricing. As such the revised second half crude oil drilling program will see increased drilling at Pelican Lake by 43% and light crude oil by 28%, while heavy crude oil drilling remains unchanged due to the lack of availability of slant drilling rigs in the basin. By Q4/06, the Company will have contracted two long-term slant drilling rigs to ensure availability of these specialized rigs on a go forward basis to execute the long-term drilling of heavy crude oil. Due to the timing of crude oil production profiles, the benefit of the ramped program during the second half of the year will not be fully realized until 2007.

As a result of the above noted changes to the drilling program, the delayed start to the North American natural gas winter drilling program earlier this year, and production issues internationally, overall Company midpoint production guidance has been decreased by 4% on a barrel of oil equivalent basis for 2006.

OPERATIONS REVIEW

Activity by core region

	Net undeveloped land as at June 30, 2006 (thousands of net acres)	Drilling activity six months ended June 30, 2006 (net wells)
Canadian conventional		
Northeast British Columbia	**2,021**	**199**
Northwest Alberta	**1,462**	**101**
Northern Plains	**6,196**	**345**
Southern Plains	**761**	**63**
Southeast Saskatchewan	**82**	**13**
	10,522	**721**
In Situ Oil Sands	**406**	**198**
Horizon Oil Sands Project	**116**	**103**
United Kingdom North Sea	**352**	**6**
Offshore West Africa	**207**	**3**
	11,603	**1,031**

Drilling activity (number of wells)

	Six Months Ended Jun 30			
	2006		2005	
	Gross	**Net**	Gross	Net
Crude oil	**196**	**171**	290	258
Natural gas	**616**	**483**	456	398
Dry	**80**	**68**	80	72
Subtotal	**892**	**722**	826	728
Stratigraphic test / service wells	**310**	**309**	201	199
Total	**1,202**	**1,031**	1,027	927
Success rate (excluding stratigraphic test / service wells)		**91%**		90%

North America natural gas

	Quarterly Results			Six Month Results	
	Q2/06	Q1/06	Q2/05	**2006**	2005
Natural gas production (mmcf/d)	**1,448**	1,411	1,434	**1,430**	1,432
Net wells targeting natural gas	**48**	499	68	**547**	454
Net successful wells drilled	**43**	440	60	**483**	398
Success rate	**90%**	88%	88%	**88%**	88%

- Q2/06 saw record natural gas production and represented a 3% increase over Q1/06, reflecting results from the winter drilling program.

- As mentioned in Q1/06, approximately 70 mmcf/d of natural gas production remained behind pipe at the end of Q1/06. During Q2/06 over half of this natural gas was tied in; however, approximately 20-30 mmcf/d will remain stranded until winter freeze up in late Q4/06 or early Q1/07.

- High drilling success rates reflect Canadian Natural's low-risk exploitation approach and high quality land base. The Q2/06 drilling program represented an active program across the Company's core regions. In Northeast British Columbia 5 net wells targeting natural gas were drilled, while in Northwest Alberta 16 net wells were drilled, including 9 Cardium targets. In Northern and Southern Plains, a total of 5 net coal bed methane, 16 net shallow natural gas and 6 net conventional natural gas wells were drilled.

- Planned drilling activity for Q3/06 includes 105 wells targeting natural gas, a reduction of 243 wells from original plan, as capital is reallocated to crude oil projects currently receiving record well head pricing.

North America crude oil and NGLs

	Quarterly Results			Six Month Results	
	Q2/06	Q1/06	Q2/05	**2006**	2005
Crude oil and NGLs production (bbl/d)	**234,780**	222,955	215,693	**228,901**	212,427
Net wells targeting crude oil	**78**	90	153	**168**	267
Net successful wells drilled	**76**	88	146	**164**	252
Success rate	**97%**	98%	95%	**98%**	94%

- Q2/06 represented record North America crude oil and NGLs production which was a 5% increase over Q1/06 and a 9% increase over Q2/05. This performance reflected continued success at the Primrose thermal crude oil project and continued production improvements at Pelican Lake.

- During Q2/06, drilling activity included 23 net wells targeting heavy crude oil, 37 net wells targeting Pelican Lake crude oil, 6 net wells targeting Thermal crude oil and 12 net wells targeting light crude oil. The majority of the wells, 67 of 78 net wells targeting crude oil during Q2/06, were drilled in the Northern Plains core region.

- The Primrose East expansion program continues through the regulatory phase and, if approved, will see the expansion of the crude oil processing facility from 80,000 bbl/d to 120,000 bbl/d, as well as the construction of a steam generation plant and new pad drilling that will add production gains targeted at 30,000 bbl/d in 2009. Primrose East is the first phase of the 300,000 bbl/d of conventional expansion plans identified for unlocking the value from Canadian Natural's 3 billion barrels of recoverable heavy crude oil resource potential.

- At Pelican Lake, the development of land acreage and secondary recovery implementation projects continued as planned, with 37 horizontal producing wells drilled in Q2/06. Results from the polymer flood pilot continue to be positive and results will continue to be monitored. A final decision on the commercial polymer flood project will be made in Q1/07 and in preparation four polymer skid installations were commenced in Q2/06. During the remainder of 2006, the Company plans to drill an additional 100 wells at Pelican Lake. Production increased from approximately 29,000 bbl/d in Q1/06 to approximately 30,000 bbl/d in Q2/06.

- Planned drilling activity for Q3/06 includes 295 net crude oil wells, an increase of 54 wells from original plan with the majority of the additional wells targeting light crude oil and Pelican Lake crude oil.

Canadian Natural Upgrader Project

Originally announced in the fall of 2005, the Company remains on track with its plans to design, construct and operate a heavy crude oil upgrader to process its conventional heavy and thermal heavy crude oil production. The Scoping Study for the Canadian Natural Upgrader continued on schedule during Q2/06. The terms of reference for this study will evaluate end product alternatives, location, technology, gasification and integration with existing assets. Recommendations are expected in early 2007 and represent the first stage of front end loading for the project. This is the same disciplined approach utilized in the Horizon Project. Following this Study, the Design Basis Memorandum and Engineering Design Specification will be completed prior to construction and sanctioning of the project by the Board of Directors.

This upgrader is expected to enable the Company to unlock significant shareholder value through the development and upgrading of over 3 billion barrels of thermal in-situ oil sands resources over the next 15 years. The project is expected to be undertaken in two phases, with the first phase targeting upgrading capacity of 125 mbbl/d of SCO currently targeted to start up in 2013.

International

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

	Quarterly Results			Six Month Results	
	Q2/06	Q1/06	Q2/05	**2006**	2005
Crude oil production (bbl/d)					
North Sea	**63,703**	60,802	62,884	**62,261**	66,989
Offshore West Africa	**40,369**	39,905	10,487	**40,137**	9,021
Natural gas production (mmcf/d)					
North Sea	**17**	17	17	**17**	20
Offshore West Africa	**10**	8	3	**9**	3
Net wells targeting crude oil	**2.8**	4.2	4.2	**7.0**	7.1
Net successful wells drilled	**2.8**	4.2	3.4	**7.0**	5.7
Success rate	**100%**	100%	81%	**100%**	80%

North Sea

- Canadian Natural continues to execute its exploitation strategy in the North Sea. The first stage of this exploitation program is based upon optimizing existing facilities and waterfloods. Canadian Natural continues to apply this first stage of exploitation on its holdings in the North Sea. 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. In 2006 and beyond, increasing emphasis on this type of work is evidenced by the ongoing development at the Columba Terraces and the Lyell Field.
- During Q2/06, 2.8 net wells were drilled with an additional 1.0 net well drilling over quarter end. Production levels were in line with expectations and were up over the previous quarter, reflecting growth at T-Block and Ninian following the delivery of successful infill wells during late Q1/06 and Q2/06. Processing issues at Murchison, which had been affecting production in the prior quarter, were successfully addressed during a planned shutdown.
- Plans for the further development of the Lyell Field progressed, which entails drilling four net wells and working over two existing net wells in 2006/7. At its plateau, new production of approximately 20,000 boe/d is forecast from this field.

Offshore West Africa

- During Q2/06, 0.6 net wells were drilled with an additional 0.6 net wells drilling over quarter end.
- At the Espoir Field, crude oil production reached a record level of approximately 20,000 bbl/d net to Canadian Natural during Q2/06. The infill drilling program on East Espoir was completed on time and on budget during Q2/06 and the rig was moved to the West Espoir tower where it commenced drilling. The West Espoir project continues on time and on budget with initial production at the end of July from the first of seven producing wells. Production will ramp to 13,000 boe/d when fully developed in early 2007.
- Net production at Baobab averaged approximately 21,000 bbl/d during the quarter. Production from 4 of 10 producer wells is currently curtailed due to the limitations resulting from sand screen effectiveness, resulting in approximately 12,000 bbl/d of reduced production capacity at the field. Modifications to the FPSO to allow for sand handling are being engineered. During Q2/06 the final water injector well from the first phase of the development was completed and the rig released. Canadian Natural is currently investigating the rig market to identify suitable availability to proceed to the second phase of the field development, including potentially redrilling the wells that are currently experiencing production limitations due to the amount of sand included with production.

- In Gabon, front end engineering and pre-planning on the Olowi Field development continued with invitations to tender for the FPSO, drilling rig and well head towers being issued during the quarter. A site survey of the field has now commenced. The development plan comprises an FPSO and four drilling towers and is expected to commence in late 2006, with first crude oil targeted for late 2008 to reach a plateau of 20,000 bbl/d.

Horizon Oil Sands Project ("Horizon Project")

- Phase 1 of the Horizon Project continues slightly ahead of schedule and continues to track to budget targets. First production of 110,000 bbl/d of light, sweet Synthetic Crude Oil from Phase 1 construction is targeted to commence in the second half of 2008. Production is targeted to increase to 155,000 bbl/d following completion of Phase 2 in 2010. Production levels of 232,000 bbl/d are targeted for 2012, following completion of Phase 3 construction. The Company is currently evaluating the opportunity to combine Phase 2 and 3 with a decision on the merits of the combination to be made in 2007.

- As a result of better labour productivity, the progress on major milestones, a key component in achieving critical path success, are slightly ahead of schedule and safety performance remained ahead of target.

- The high degree of up front project engineering and pre-planning has reduced the risks on "cost-plus" aspects of the project and will mitigate the risk of scope changes on the fixed bid portions (targeted at 68% of Phase 1 costs). The pre-engineering and lessons learned from predecessors have also enabled the Company to prepare a detailed development and logistical plan to reduce the scheduling risk. Geological risk is considered low on the Company's mining leases at over 16 delineation wells have been drilled per section, with over 40 wells per section having been drilled on the south pit, which will be the first to be mined. Finally, technology risk is low as the Company is using existing proved technologies for mining, extraction and upgrading processes.

- Construction capital costs for Phase 1 of the Horizon Project are budgeted at $6.8 billion, with $2.6 billion spent to date, $1.3 billion targeted to be incurred in the remainder of 2006 and $2.9 billion targeted to be incurred in 2007 and 2008.

- During Q2/06, the Company awarded a further C$400 million of contracts, including several that were previously deferred in order to optimize pricing. As such, with C$4.4 billion in awarded contracts and a budgeted C$900 million for internal costs, Canadian Natural already has a high degree of cost certainty on C$5.3 billion of Phase 1 construction costs. Additionally all major plants have been passed through hazard/operability review without requiring major scope changes, providing even greater cost certainty on these items. Of the remaining elements, the Company has received initial indications on an additional C$400 million in contract work currently in the tender process and has a good sense of these costs, leaving about C$400 million of cost exposure on several hundred smaller contracts to be let.

- The quarterly update for the project is as follows:

Project status summary

	Jun 30, 2006		Sep 30, 2006
	Actual	Plan	Plan
Phase 1 - Work progress (cumulative)	**36%**	31%	44%
Phase 1 - Construction capital spending (cumulative)	**37%**	39%	49%

Accomplished During the Second Quarter

<u>Detailed Engineering</u>

- Completed in excess of 80% of overall detailed engineering model reviews in all areas.
- 90% of model reviews completed, with detailed engineering on the critical path Coker/DRU plant completed two months ahead of schedule.

<u>Procurement</u>

- Awarded in excess of C$400 million of contracts and purchase orders in the quarter, bringing awards-to-date to over C$4.4 billion, with a further C$400 million in various stages of the tender process.
- Awarded contract for the purchase of 23 Mining Trucks.
- Awarded key construction contracts in Extraction, Froth Treatment and Tank Farms.
- Advanced mine equipment purchase (C$24 million) by one year to ensure delivery in late 2006 to accommodate self performed Tar River Diversion and Raw Water Pond construction.

<u>Modularization</u>

- To date, in excess of 330 oversized loads, or 20% of Phase 1 totals, have been transported to site.
- Shifted module assembly work between contractors in order to improve efficiency and maintain schedule.

<u>Construction</u>

- Achieved a Safety Milestone of 5 million Loss Time Accident free site hours - safety performance remains ahead of benchmarked targets.
- Ore Preparation Plant site turned over by Mining to Bitumen Production, two months ahead of base plan.
- Set 140 piperack modules for total progress of 31% complete.
- Mine Overburden Administration and Maintenance Facility were completed and occupied.
- Commissioned the new 40 m3 hydraulic shovel in the quarter. To date, 17.0 million bank cubic meters (approximately 24% of total requirement) of overburden has been removed compared to a plan of 16.0 million bank cubic meters.
- Substantially completed site preparation and underground facilities.
- Camp 2 turned over to operator and ready for occupancy, one month ahead of schedule.

Third Quarter 2006 Milestones

- Overall detailed engineering to surpass 90% complete.
- Mining shovels to be ordered.
- Commence Tar River Diversion and Raw Water Pond construction project.

MARKETING

	Quarterly Results			Six Months Results	
	Q2/06	Q1/06	Q2/05	**2006**	2005
Crude oil and NGLs pricing					
WTI[1] benchmark price (US$/bbl)	**$ 70.70**	$ 63.53	$ 53.13	**$ 67.14**	$ 51.53
Lloyd Blend Heavy oil differential from WTI (%)	**25%**	45%	40%	**35%**	39%
Corporate average pricing before risk management (C$/bbl)	**$ 60.05**	$ 43.79	$ 42.51	**$ 52.22**	$ 41.17
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 5.95**	$ 8.82	$ 7.00	**$ 7.37**	$ 6.67
Corporate average pricing before risk management (C$/mcf)	**$ 6.16**	$ 8.30	$ 7.33	**$ 7.21**	$ 7.01

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

- Heavy crude oil differentials narrowed significantly in Q2/06 averaging 25% of WTI, coincident with the reversal of the Pegasus (formerly known as Corsicana) and Spearhead Pipelines, a third party outage, and normal seasonality. Canadian Natural continues to work with various industry groups and strategic partners to find new markets for Western Canadian heavy crude oil in order to mitigate the impact of supply and demand shocks on the heavy crude oil market in North America.

- During Q2/06, the Company contributed approximately 142 mbbl/d of its heavy crude oil streams to the Western Canadian Select (“WCS”) blend as market conditions resulted in this strategy offering the optimal pricing for bitumen.

- Under its three phase heavy crude oil marketing plan, Canadian Natural continues to encourage the development of additional heavy crude oil conversion capacity. Early in Q3/06 Canadian Natural entered into an agreement to sell 25 mbbl/d of heavy crude oil production to a new merchant upgrader to be constructed in Alberta. The agreement is for a period of 5 years, with first deliveries anticipated to occur in 2010 upon completion of construction of the facilities.

- AECO benchmark pricing for natural gas was 33% lower than in the previous quarter, reflecting the impact of high storage levels in North America as a result of a very warm winter.

FINANCIAL REVIEW

- Canadian Natural has structured its financial position so as to be able 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 580 mboe/d in Q2/06, comprised of approximately 42% natural gas and 58% crude oil - with 93% of production located in G7 countries with stable and secure economies.

  – Financial stability and liquidity - $3.5 billion of bank credit facilities, of which Canadian Natural had in aggregate $1.9 billion of unused bank lines available at June 30, 2006.

  – Strong balance sheet - with a debt to book capitalization ratio of 35%, debt to cash flow of 1.0x, debt to EBITDA of 0.9x and shareholders’ equity of $9.3 billion.

- In January 2005, the Board of Directors authorized the expansion of the Company's commodity hedging program to reduce the risk of volatility in commodity price markets and to support the Company's cash flow for its capital expenditure program throughout the Horizon Project construction period. This expanded 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 through the use of derivative financial instruments. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. As a result, approximately 75% of budgeted 2006 crude oil volumes (2007F – 25%), and approximately 65% of budgeted 2006 natural gas volumes (2007F – 60%), have been hedged through the use of collars for the remainder of 2006.

- As effective as economic hedges are against reference commodity prices, a substantial portion of the 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 Company is required to mark-to-market these non-designated hedges based on prevailing forward commodity prices in effect at the end of each reporting period. Accordingly, the unrealized risk management liability reflects, at June 30, 2006, the implied price differentials for the non-designated hedges in 2006 and future years. Due to the changes in crude oil and natural gas forward pricing, the Company recorded a net $18 million ($12 million after tax) unrealized gain on its risk management activities for the six months ended June 30, 2006. 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 production.

- During Q2/06, the Canadian Federal Government enacted reductions to its corporate tax rates, resulting in a reduction of future income tax liabilities of approximately $277 million.

- During Q2/06, the provinces of Alberta and Saskatchewan enacted reductions to their corporate income tax rates, resulting in a reduction of future tax liabilities of approximately $161 million.

- During Q2/06 under the terms of the Normal Course Issuer Bid, which allows for the repurchase by the Company of up to 26.9 million shares through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, 390,000 common shares were repurchased at an average price of $56.93/share.

OUTLOOK

The Company has revised its annual production guidance and currently expects 2006 production levels before royalties to average 1,422 to 1,450 mmcf/d of natural gas and 327 to 350 mbbl/d of crude oil and NGLs. Q3/06 production guidance before royalties is 1,416 to 1,445 mmcf/d of natural gas and 318 to 340 mbbl/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", 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. 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 ("MD&A") of the financial condition and results of operations of Canadian Natural Resources Limited (the "Company"), should be read in conjunction with the unaudited interim consolidated financial statements for the six months ended June 30, 2006 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2005.

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, cash flow from operations, and EBITDA (net earnings before interest, taxes, depreciation, depletion and amortization, asset retirement obligation accretion, unrealized foreign exchange, stock-based compensation expense and unrealized risk management activities). 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 prior period amounts have been reclassified to enable comparison with the current period's presentation.

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 well head.

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 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, 2006 in relation to the comparable periods in 2005 and the first quarter of 2006. The accompanying tables form an integral part of this MD&A. This MD&A is dated July 28, 2006.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Six Months Ended	
	Jun 30 2006	Mar 31 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
Revenue, before royalties	**$ 2,717**	$ 2,372	$ 2,164	**$ 5,089**	$ 4,157
Net earnings (loss)	**$ 1,038**	$ 57	$ 219	**$ 1,095**	$ (205)
Per common share – basic	**$ 1.93**	$ 0.11	$ 0.41	**$ 2.04**	$ (0.38)
– diluted	**$ 1.93**	$ 0.11	$ 0.41	**$ 2.04**	$ (0.38)
Adjusted net earnings from operations(1)	**$ 514**	$ 268	$ 460	**$ 782**	$ 840
Per common share – basic	**$ 0.96**	$ 0.50	$ 0.86	**$ 1.46**	$ 1.57
– diluted	**$ 0.96**	$ 0.50	$ 0.86	**$ 1.46**	$ 1.57
Cash flow from operations(2)	**$ 1,287**	$ 1,039	$ 1,136	**$ 2,326**	$ 2,145
Per common share – basic	**$ 2.40**	$ 1.93	$ 2.12	**$ 4.33**	$ 4.00
– diluted	**$ 2.40**	$ 1.93	$ 2.12	**$ 4.33**	$ 4.00
Capital expenditures, net of dispositions	**$ 1,558**	$ 2,309	$ 609	**$ 3,867**	$ 1,981

(1) 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 2006***	*Mar 31 2006*	*Jun 30 2005*	***Jun 30 2006***	*Jun 30 2005*
Net earnings (loss) as reported	***$ 1,038***	*$ 57*	*$ 219*	***$ 1,095***	*$ (205)*
Stock-based compensation (recovery) expense, net of tax(a)	***(21)***	*88*	*146*	***67***	*271*
Unrealized risk management (gain) loss, net of tax(b)	***(17)***	*5*	*81*	***(12)***	*760*
Unrealized foreign exchange (gain) loss, net of tax(c)	***(48)***	*8*	*14*	***(40)***	*14*
Effect of statutory tax rate changes on future income tax liabilities(d)	***(438)***	*110*	*-*	***(328)***	*-*
Adjusted net earnings from operations	***$ 514***	*$ 268*	*$ 460*	***$ 782***	*$ 840*

(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) Financial instruments not designated as hedges are recorded at fair value on the balance sheet, with changes in fair value, 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 its future income tax assets and liabilities. The impact of the tax rate changes is recorded in net earnings in the period the legislation is substantively enacted. During the first quarter of 2006, the UK government substantively enacted an increase to the supplementary charge on profits from UK North Sea crude oil and natural gas production, resulting in an increase of future tax liabilities of $110 million. During the second quarter of 2006, the Canadian Federal Government enacted reductions to its corporate tax rates, resulting in a reduction of future income tax liabilities of approximately $277 million. Also during the second quarter of 2006, the provinces of Alberta and Saskatchewan enacted reductions to their corporate income tax rates, resulting in a reduction of future tax liabilities of approximately $161 million.

(2) 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 2006***	*Mar 31 2006*	*Jun 30 2005*	***Jun 30 2006***	*Jun 30 2005*
Net earnings (loss)	***$ 1,038***	*$ 57*	*$ 219*	***$ 1,095***	*$ (205)*
Non-cash items:					
Depletion, depreciation and amortization	***557***	*521*	*484*	***1,078***	*958*
Asset retirement obligation accretion	***16***	*17*	*17*	***33***	*35*
Stock-based compensation (recovery) expense	***(34)***	*132*	*215*	***98***	*399*
Unrealized risk management activities	***(26)***	*8*	*119*	***(18)***	*1,117*
Unrealized foreign exchange (gain) loss	***(58)***	*10*	*16*	***(48)***	*16*
Deferred petroleum revenue tax	***18***	*26*	*4*	***44***	*4*
Future income tax (recovery) expense	***(224)***	*268*	*62*	***44***	*(179)*
Cash flow from operations	***$ 1,287***	*$ 1,039*	*$ 1,136*	***$ 2,326***	*$ 2,145*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

For the six months ended June 30, 2006, the Company reported net earnings of $1,095 million compared to a net loss of $205 million for the six months ended June 30, 2005. Net earnings for the six months ended June 30, 2006 included unrealized after-tax income of $313 million related to the effects of statutory tax rate changes on future income tax liabilities, stock-based compensation expense, foreign exchange gains and risk management activities. This compared to $1,045 million of net after-tax expenses for the six months ended June 30, 2005. Excluding these items, adjusted net earnings from operations for the six months ended June 30, 2006 decreased by 7% to $782 million from $840 million for the six months ended June 30, 2005, primarily due to increased realized losses from risk management activities and the impact of a stronger Canadian dollar relative to the US dollar. These factors were partially offset by stronger product pricing and increased production.

For the second quarter of 2006, the Company reported net earnings of $1,038 million compared to net earnings of $219 million in the second quarter of 2005 and net earnings of $57 million for the prior quarter. Net earnings in the second quarter of 2006 included unrealized after-tax income of $524 million related to the effects of statutory tax rate changes on future income tax liabilities, stock-based compensation recovery, foreign exchange gains and risk management activities, compared to net expenses of $241 million in the second quarter of 2005 and $211 million in the prior quarter. Excluding these items, adjusted net earnings from operations in the second quarter of 2006 increased by 12% to $514 million from $460 million in the comparable period in 2005, and increased 92% from $268 million in the prior quarter. The increase from the comparable period in 2005 and the prior quarter was primarily due to stronger crude oil prices and increased crude oil production, partially offset by decreased natural gas prices in the second quarter of 2006, increased realized losses from risk management activities and the impact of a stronger Canadian dollar.

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

The Board of Directors authorized the expansion of the Company's commodity hedging program to reduce the risk of volatility in commodity price markets and to support the Company's cash flow for its capital expenditure program throughout the Horizon Oil Sands Project ("Horizon Project") construction period. This expanded 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 through the use of derivative financial instruments. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. As a result, approximately 75% of budgeted crude oil volumes and approximately 65% of budgeted natural gas volumes have been hedged through the use of collars for the remainder of 2006. In addition, approximately 25% of estimated 2007 crude oil volumes and approximately 60% of estimated 2007 natural gas volumes have been hedged through the use of collars.

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 Company is required to mark-to-market these non-designated hedges based on prevailing forward commodity prices in effect at the end of each reporting period. Accordingly, the unrealized risk management liability reflects, at June 30, 2006, the implied price differentials for the non-designated hedges for future periods. The cash settlement amount of the risk management financial derivative instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their mark-to-market value at June 30, 2006.

Due to the changes in crude oil and natural gas forward pricing, the Company recorded a net $18 million ($12 million after-tax) unrealized gain on its risk management activities for the six months ended June 30, 2006, including a $26 million ($17 million after-tax) unrealized gain for the three months ended June 30, 2006. 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 production.

The Company also recorded a $98 million ($67 million after-tax) stock-based compensation expense for the six months ended June 30, 2006 in connection with the 7% appreciation in the Company's share price, and a $34 million ($21 million after-tax) stock-based compensation recovery as a result of the decrease in the Company's share price for the three months ended June 30, 2006 (Company's share price as at: June 30, 2006 - C$61.72; March 31, 2006 - C$64.90; December 31, 2005 - C$57.63; June 30, 2005 - C$44.40). As required by GAAP, the Company records a liability for potential cash payments to settle its outstanding employee stock options, 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 earnings, or capitalized during the construction period in the case of the Horizon Project. The stock-based compensation liability reflects the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on June 30, 2006. In periods when substantial stock 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, 2006 increased 8% to $2,326 million from $2,145 million for the six months ended June 30, 2005. Cash flow from operations in the second quarter of 2006 increased 13% to $1,287 million from $1,136 million for the second quarter of 2005 and increased 24% from $1,039 million in the prior quarter. The increase in cash flow from operations from the comparable periods in 2005 and the prior quarter was primarily due to stronger crude oil prices and increased crude oil production, partially offset by increased realized losses from risk management activities and the impact of a stronger Canadian dollar relative to the US dollar.

Total production before royalties averaged 573,879 boe/d for the six months ended June 30, 2006, up 8% from 530,851 boe/d for the six months ended June 30, 2005. Production for the second quarter of 2006 increased 10% to 584,611 boe/d from 531,380 boe/d in the second quarter of 2005 and increased 4% from 563,027 boe/d in the prior quarter.

OPERATING HIGHLIGHTS

	Three Months Ended			Six Months Ended	
	Jun 30 2006	Mar 31 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
Crude oil and NGLs ($/bbl)[1]					
Sales price[2]	**$ 60.05**	$ 43.79	$ 42.51	**$ 52.22**	$ 41.17
Royalties	**5.14**	3.48	3.33	**4.34**	3.36
Production expense	**11.92**	11.33	11.66	**11.63**	11.48
Netback	**$ 42.99**	$ 28.98	$ 27.52	**$ 36.25**	$ 26.33
Natural gas ($/mcf)[1]					
Sales price[2]	**$ 6.16**	$ 8.30	$ 7.33	**$ 7.21**	$ 7.01
Royalties	**1.11**	1.70	1.48	**1.40**	1.39
Production expense	**0.80**	0.80	0.71	**0.80**	0.71
Netback	**$ 4.25**	$ 5.80	$ 5.14	**$ 5.01**	$ 4.91
Barrels of oil equivalent ($/boe)[1]					
Sales price[2]	**$ 50.36**	$ 46.30	$ 43.05	**$ 48.39**	$ 41.51
Royalties	**5.80**	6.44	5.85	**6.11**	5.64
Production expense	**8.85**	8.46	8.29	**8.66**	8.17
Netback	**$ 35.71**	$ 31.40	$ 28.91	**$ 33.62**	$ 27.70

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

(2) Including transportation costs and excluding risk management activities.

BUSINESS ENVIRONMENT

	Three Months Ended			Six Months Ended	
	Jun 30 2006	Mar 31 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
WTI benchmark price (US$/bbl)	**$ 70.70**	$ 63.53	$ 53.13	**$ 67.14**	$ 51.53
Dated Brent benchmark price (US$/bbl)	**$ 69.63**	$ 61.80	$ 51.55	**$ 65.74**	$ 49.64
Dated Brent differential from WTI (%)	**2%**	3%	3%	**2%**	4%
Differential to LLB blend (US$/bbl)	**$ 17.79**	$ 28.70	$ 21.22	**$ 23.21**	$ 20.25
LLB blend differential from WTI (%)	**25%**	45%	40%	**35%**	39%
Condensate benchmark price (US$/bbl)	**$ 71.51**	$ 63.63	$ 53.56	**$ 67.59**	$ 52.51
NYMEX benchmark price (US$/mmbtu)	**$ 6.83**	$ 9.10	$ 6.80	**$ 7.96**	$ 6.56
AECO benchmark price (C$/GJ)	**$ 5.95**	$ 8.82	$ 7.00	**$ 7.37**	$ 6.67
US / Canadian dollar average exchange rate (US$)	**0.8918**	0.8660	0.8038	**0.8786**	$ 0.8094

World crude oil prices remained strong in the second quarter of 2006 despite high crude oil inventories, due to continued demand growth and an escalation in ongoing geopolitical uncertainties.

West Texas Intermediate ("WTI") averaged US$67.14 per bbl for the six months ended June 30, 2006, an increase of 30% compared to US$51.53 per bbl for the six months ended June 30, 2005. In the second quarter of 2006, WTI averaged US$70.70 per bbl, an increase of 33% from US$53.13 per bbl in the comparable period in 2005 and an increase of 11% from US$63.53 per bbl in the prior quarter. The Company's realized crude oil price increased as a result of the increased WTI price and the narrower Heavy Crude Oil Differential from WTI ("Heavy Differential") in its North America segment. Heavy Differentials averaged 35% for the six months ended June 30, 2006 compared to 39% for the six months ended June 30, 2005. For the three months ended June 30, 2006, Heavy Differentials decreased to average 25% compared to 40% for the second quarter of 2005 and 45% for the prior quarter. The narrowing of the Heavy Differential in the second quarter of 2006 was primarily due to increased seasonal demand for heavy crude oil, a third party outage and the reversal of the Pegasus (formerly known as Corsicana) and Spearhead pipelines, which expanded the markets for the Company's heavy crude oil production into the US Gulf Coast and Midwest. The increase in North America realized crude oil prices from the comparable periods in 2005 was partially offset by the impact of a strengthening Canadian dollar relative to the US dollar. A strengthening Canadian dollar reduces the Canadian dollar sales price the Company receives for its crude oil sales, as crude oil prices are based on US dollar denominated benchmarks.

The Company continues to benefit from narrower Heavy Differentials in the third quarter of 2006, with differentials in the month of July 2006 currently trending at 23% of WTI.

In addition, Dated Brent ("Brent") averaged US$65.74 per bbl for the six months ended June 30, 2006, an increase of 32% compared to US$49.64 per bbl for the six months ended June 30, 2005. In the second quarter of 2006, Brent averaged US$69.63 per bbl, an increase of 35% from US$51.55 per bbl in the comparable period in 2005 and an increase of 13% from US$61.80 per bbl in the prior quarter. Crude oil sales contracts for the Company's North Sea and Offshore West Africa regions are typically based on Brent pricing, which have benefited from strong European and Asian demand.

NYMEX natural gas prices averaged US$7.96 per mmbtu for the six months ended June 30, 2006, an increase of 21% from US$6.56 per mmbtu for the six months ended June 30, 2005. In the second quarter of 2006, the NYMEX natural gas price averaged US$6.83 per mmbtu, relatively unchanged from US$6.80 per mmbtu in the comparable period in 2005, and decreased 25% from US$9.10 per mmbtu in the prior quarter. AECO natural gas pricing moved directionally with NYMEX, decreasing 33% from the prior quarter to C$5.95 per GJ. The increase in natural gas prices from the six months ended June 30, 2005 reflected concerns around supply early in the year as well as the impact of higher crude oil prices. The decrease from the second quarter of 2005 and the prior quarter was due to the impact of the exceptionally mild winter weather experienced in the first quarter of 2006, resulting in weaker demand and high natural gas inventory levels.

PRODUCT PRICES[1]

	Three Months Ended			Six Months Ended	
	Jun 30 2006	Mar 31 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
Crude oil and NGLs ($/bbl)[2]					
North America	**$ 54.94**	$ 34.16	$ 35.24	**$ 45.04**	$ 33.79
North Sea	**$ 73.19**	$ 68.05	$ 64.81	**$ 70.68**	$ 62.04
Offshore West Africa	**$ 72.97**	$ 65.23	$ 58.24	**$ 69.10**	$ 59.95
Company average	**$ 60.05**	$ 43.79	$ 42.51	**$ 52.22**	$ 41.17
Natural gas ($/mcf)[2]					
North America	**$ 6.21**	$ 8.39	$ 7.38	**$ 7.28**	$ 7.06
North Sea	**$ 2.33**	$ 2.38	$ 3.07	**$ 2.36**	$ 3.33
Offshore West Africa	**$ 5.30**	$ 5.59	$ 6.88	**$ 5.43**	$ 7.20
Company average	**$ 6.16**	$ 8.30	$ 7.33	**$ 7.21**	$ 7.01
Company average ($/boe)[2]	**$ 50.36**	$ 46.30	$ 43.05	**$ 48.39**	$ 41.51
Percentage of revenue (excluding midstream revenue)					
Crude oil and NGLs	**62%**	53%	54%	**54%**	54%
Natural gas	**38%**	47%	46%	**46%**	46%

(1) Including transportation 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 27% to average $52.22 per bbl for the six months ended June 30, 2006 from $41.17 per bbl for the six months ended June 30, 2005. Realized crude oil prices for the second quarter of 2006 increased 41% to average $60.05 per bbl from $42.51 per bbl in the second quarter of 2005 and increased 37% from $43.79 per bbl in the prior quarter. The increase from the comparable periods in 2005 was due to higher benchmark crude oil prices, narrower Heavy Differentials, and an increased proportion of higher value crude oil sales coming from Offshore West Africa. This increase was partially offset by the impact of a stronger Canadian dollar.

The Company's realized natural gas price increased 3% to average $7.21 per mcf for the six months ended June 30, 2006 from $7.01 per mcf for the six months ended June 30, 2005, primarily due to supply concerns as well as the impact of higher crude oil prices. This was offset by the impact of exceptionally mild weather experienced in the first quarter of 2006, which resulted in reduced seasonal heating demand and high natural gas inventory levels. In the second quarter of 2006, the Company's realized natural gas price decreased 16% from $7.33 per mcf in the second quarter of 2005 and decreased 26% from $8.30 per mcf for the prior quarter primarily as a result of weaker demand and high natural gas inventory levels.

North America

North America realized crude oil prices increased 33% to average $45.04 per bbl for the six months ended June 30, 2006 from $33.79 per bbl for the six months ended June 30, 2005. Realized crude oil prices in the second quarter of 2006 averaged $54.94 per bbl, a 56% increase from $35.24 per bbl in the comparable period in 2005 and increased 61% from $34.16 per bbl in the prior quarter. The increase from the comparable periods in 2005 was due to higher benchmark crude oil prices and a narrower Heavy Differential. This increase was partially offset by the impact of a stronger Canadian dollar. The increase from the prior quarter also reflected these factors, partially offset by a heavier product mix.

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 142,000 bbl/d of heavy crude oil blends to the Western Canadian Select ("WCS") stream. The Company also continues to work with refiners to advance expansion of heavy crude oil conversion capacity, and is working with pipeline companies to develop new capacity to the Canadian west coast and the US Gulf Coast where crude oil cargos can be sold on a world-wide basis. The Company has committed to 25,000 bbl/d of capacity on the Pegasus Pipeline, which carries crude oil to the Gulf of Mexico with a view to expanding markets for its heavy crude oil. The Pegasus Pipeline is made up of a series of segments extending from Patoka, Illinois to Nederland, Texas, near the Gulf Coast. The Company's first sales from the Pegasus pipeline occurred on April 6, 2006. In the third quarter of 2006, the Company entered into an agreement to supply 25,000 bbl/d of heavy crude oil production to a new merchant upgrader to be constructed in Alberta. The agreement is for a period of five years with first deliveries anticipated to occur in 2010 upon completion of construction of the facilities.

North America realized natural gas prices increased 3% to average $7.28 per mcf for the six months ended June 30, 2006 from $7.06 per mcf for the six months ended June 30, 2005. The realized natural gas price in the second quarter of 2006 averaged $6.21 per mcf, a decrease of 16% from $7.38 per mcf in the comparable period in 2005 and decreased 26% from $8.39 per mcf for the prior quarter.

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

	Jun 30 2006	Mar 31 2006	Jun 30 2005
Wellhead Price[(1)(2)]			
Light / medium crude oil and NGLs (C$/bbl)	**$ 69.25**	$ 58.21	$ 55.66
Pelican Lake crude oil (C$/bbl)	**$ 56.01**	$ 31.60	$ 34.24
Primary heavy crude oil (C$/bbl)	**$ 51.78**	$ 25.91	$ 28.42
Thermal heavy crude oil (C$/bbl)	**$ 47.64**	$ 23.60	$ 26.71
Natural gas (C$/mcf)	**$ 6.21**	$ 8.39	$ 7.38

(1) Including transportation 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 14% to average $70.68 per bbl for the six months ended June 30, 2006 from $62.04 per bbl for the six months ended June 30, 2005. Realized crude oil prices in the second quarter of 2006 increased 13% to average $73.19 per bbl from $64.81 per bbl in the second quarter of 2005 and increased 8% from $68.05 per bbl in the prior quarter. The increase in the realized crude oil price from the comparable periods in 2005 and the prior quarter was due mainly to the impact of strong European and Asian demand on Brent pricing, partially offset by the strengthening Canadian dollar.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 15% to average $69.10 per bbl for the six months ended June 30, 2006 from $59.95 per bbl for the six months ended June 30, 2005. Realized crude oil prices for the second quarter of 2006 increased 25% to average $72.97 per bbl from $58.24 per bbl in the second quarter of 2005 and increased 12% from $65.23 per bbl in the prior quarter. The increase in the realized crude oil price from the comparable periods in 2005 and the prior quarter was due mainly to the impact of strong European and Asian demand on Brent pricing, partially offset by the strengthening Canadian dollar.

Crude Oil Inventory Volumes

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

(bbl)	**Jun 30 2006**	Mar 31 2006	Dec 31 2005
North America, related to pipeline fill	**1,097,526**	1,097,526	484,157
North Sea, related to timing of liftings	**2,397,640**	1,528,040	747,141
Offshore West Africa, related to timing of liftings	**832,317**	584,931	412,841
	4,327,483	3,210,497	1,644,139

For the three months ended June 30, 2006, an additional 1.1 million barrels of crude oil have been included as inventory in the Company's International operations. This inventory build reduced cash flow from operations by approximately $60 million.

DAILY PRODUCTION, before royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2006	Mar 31 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
Crude oil and NGLs (bbl/d)					
North America	**234,780**	222,955	215,693	**228,901**	212,427
North Sea	**63,703**	60,802	62,884	**62,261**	66,989
Offshore West Africa	**40,369**	39,905	10,487	**40,137**	9,021
	338,852	323,662	289,064	**331,299**	288,437
Natural gas (mmcf/d)					
North America	**1,448**	1,411	1,434	**1,430**	1,432
North Sea	**17**	17	17	**17**	20
Offshore West Africa	**10**	8	3	**9**	3
	1,475	1,436	1,454	**1,456**	1,455
Total barrel of oil equivalent (boe/d)	**584,611**	563,027	531,380	**573,879**	530,851
Product mix					
Light/medium crude oil and NGLs	**26%**	27%	24%	**27%**	24%
Pelican Lake crude oil	**5%**	5%	4%	**5%**	4%
Primary heavy crude oil	**16%**	17%	17%	**16%**	17%
Thermal heavy crude oil	**11%**	8%	9%	**10%**	9%
Natural gas	**42%**	43%	46%	**42%**	46%

DAILY PRODUCTION, net of royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2006	Mar 31 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
Crude oil and NGLs (bbl/d)					
North America	**205,674**	192,747	189,137	**199,246**	184,331
North Sea	**63,552**	60,694	62,779	**62,131**	66,903
Offshore West Africa	**39,335**	38,958	10,160	**39,148**	8,743
	308,561	292,399	262,076	**300,525**	259,977
Natural gas (mmcf/d)					
North America	**1,183**	1,120	1,143	**1,152**	1,145
North Sea	**17**	17	17	**17**	20
Offshore West Africa	**10**	8	3	**9**	3
	1,210	1,145	1,163	**1,178**	1,168
Total barrel of oil equivalent (boe/d)	**510,243**	483,143	455,866	**496,768**	454,632

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 presented for information purposes only.

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 crude oil and natural gas production averaged 573,879 boe/d for the six months ended June 30, 2006, an 8% increase from the six months ended June 30, 2005. Second quarter total production in 2006 averaged a record 584,611 boe/d, an increase of 10% compared to the second quarter of 2005 and an increase of 4% compared to the prior quarter. The increase in production from the comparable periods in 2005 was primarily due to increased production from the Company's Primrose thermal projects, the positive results from the Pelican Lake waterflood project, continued organic growth from the Company's extensive North America capital expenditure program and the commencement of production from the Baobab Field located offshore Côte d'Ivoire in the third quarter of 2005.

Total crude oil and NGLs production for the six months ended June 30, 2006 increased 15% to 331,299 bbl/d, up from 288,437 bbl/d for the six months ended June 30, 2005. In the second quarter of 2006, production increased 17% to 338,852 bbl/d from 289,064 bbl/d in the second quarter of 2005 and increased 5%, up from 323,662 bbl/d in the prior quarter. Crude oil and NGLs production in the second quarter of 2006 was in line with the Company's previously issued guidance of 326,000 to 348,000 bbl/d.

Natural gas production continues to represent the Company's largest product offering. Natural gas production for the six months ended June 30, 2006 averaged 1,456 mmcf/d compared to 1,455 mmcf/d for the six months ended June 30, 2005. In the second quarter of 2006, natural gas production averaged 1,475 mmcf/d, up 1% from 1,454 mmcf/d in the second quarter of 2005 and increased 3% from 1,436 mmcf/d in the prior quarter. The Company's second quarter natural gas production was within the Company's previously issued guidance of 1,461 to 1,520 mmcf/d.

As a result of the change to its capital program, the delayed start to the North America natural gas winter drilling program earlier in 2006 and production issues internationally, the Company has revised its annual production guidance. In 2006, production is expected to average 1,422 to 1,450 mmcf/d of natural gas and 327,000 to 350,000 bbl/d of crude oil and NGLs. Third quarter 2006 production guidance is 1,416 to 1,445 mmcf/d of natural gas and 318,000 to 340,000bbl/d of crude oil and NGLs**.**

North America

North America crude oil and NGLs production for the six months ended June 30, 2006 increased 8% to average 228,901 bbl/d, up from 212,427 bbl/d for the six months ended June 30, 2005. Production in the second quarter of 2006 increased 9% or 19,087 bbl/d to average 234,780 bbl/d, up from 215,693 bbl/d in the second quarter of 2005 and increased 5% from the prior quarter production of 222,955 bbl/d. The increase in crude oil and NGLs production was mainly due to increased Primrose production and the positive results from the Pelican Lake waterflood project.

North America natural gas production for the six months ended June 30, 2006 decreased slightly to average 1,430 mmcf/d from 1,432 mmcf/d for the six months ended June 30, 2005. In the second quarter of 2006, production increased 1% or 14 mmcf/d to average 1,448 mmcf/d, up from 1,434 mmcf/d in the second quarter of 2005 and increased 3% from 1,411 mmcf/d in the prior quarter. Production was negatively impacted by warmer than normal weather during the winter drilling season, which precluded timely access to many locations in Northern Alberta and Northeast British Columbia. The Company anticipates that approximately 20 – 30 mmcf/d will remain stranded until winter freeze up in late 2006 or early 2007.

North Sea

North Sea crude oil production for the six months ended June 30, 2006 averaged 62,261 bbl/d, 7% lower than the 66,989 bbl/d in the six months ended June 30, 2005. Crude oil production in the second quarter of 2006 increased to 63,703 bbl/d, 1% higher than production of 62,884 bbl/d in the comparable period in 2005, and 5% higher than prior quarter production of 60,802 bbl/d. Production levels were in line with expectations, reflecting completion of the Company’s infill drilling program, with positive results at the Ninian and Tiffany Fields, and the resolution of processing difficulties at the Murchison Field. Due to the positive results from the Company’s infill drilling program, the Ninian Field produced a peak rate of 43,725 bbl/d, which is the highest rate of production from this Field since the Company assumed Operatorship. Production in the third quarter of 2006 is expected to decrease due to the timing of maintenance work.

Offshore West Africa

Offshore West Africa crude oil production for the six months ended June 30, 2006 increased 345% to 40,137 bbl/d from 9,021 bbl/d for the six months ended June 30, 2005. The production increase was primarily due to commencement of production from the 57.61% owned and operated Baobab Field in August 2005. Second quarter 2006 production increased by 285% from 10,487 bbl/d in the second quarter of 2005 primarily due to production from the Baobab Field and positive results from the Company’s infill drilling program at East Espoir. Four production wells at Baobab experienced increased sand and solids production and were curtailed, reducing production by approximately 12,000 bbl/d, net to the Company. By way of offset, two production wells were added at East Espoir, resulting in record production at this Field during the quarter.

ROYALTIES

	Three Months Ended			Six Months Ended	
	Jun 30 2006	Mar 31 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
Crude oil and NGLs ($/bbl)[1]					
North America	**$ 6.81**	$ 4.63	$ 4.34	**$ 5.77**	$ 4.45
North Sea	**$ 0.17**	$ 0.12	$ 0.11	**$ 0.15**	$ 0.08
Offshore West Africa	**$ 1.87**	$ 1.55	$ 1.81	**$ 1.71**	$ 1.85
Company average	**$ 5.14**	$ 3.48	$ 3.33	**$ 4.34**	$ 3.36
Natural gas ($/mcf)[1]					
North America	**$ 1.13**	$ 1.73	$ 1.50	**$ 1.43**	$ 1.41
North Sea	**$ -**	$ -	$ -	**$ -**	$ -
Offshore West Africa	**$ 0.14**	$ 0.13	$ 0.21	**$ 0.13**	$ 0.22
Company average	**$ 1.11**	$ 1.70	$ 1.48	**$ 1.40**	$ 1.39
Company average ($/boe)[1]	**$ 5.80**	$ 6.44	$ 5.85	**$ 6.11**	$ 5.64
Percentage of revenue[2]					
Crude oil and NGLs	**9%**	8%	9%	**8%**	9%
Natural gas	**18%**	21%	20%	**20%**	20%
Boe	**12%**	14%	14%	**13%**	14%

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

(2) Including transportation costs and excluding risk management activities.

North America

North America crude oil and NGLs royalties per bbl for the six and three months ended June 30, 2006 increased from the comparable periods in 2005 and the prior quarter primarily due to higher benchmark world crude oil prices and narrower Heavy Differentials. Based on current pricing, payout on the Primrose thermal projects is anticipated to be reached late in the third or early in the fourth quarter of 2006, at which point Crown royalty rates will increase from 1% of gross revenue to 25% of revenue net of operating costs and capital expenditures.

Natural gas royalties per mcf fluctuated from the comparable periods in 2005 and the prior quarter in response to benchmark natural gas prices, which were impacted by changes in demand and storage levels for natural gas.

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 revenue and profit revenue. Cost recovery revenue allows the Company to recover its capital and operating costs and the costs carried by the Company on behalf of the Government State Oil Company. These revenues are reported as sales revenue. Profit revenue 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 revenue attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the PSCs. Based on current projections, the Espoir Field is expected to reach payout in late 2006, while the Baobab Field is expected to reach payout in 2008, which will increase royalty rates and current income taxes in accordance with the PSCs.

PRODUCTION EXPENSE

	Three Months Ended			Six Months Ended	
	Jun 30 2006	Mar 31 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
Crude oil and NGLs ($/bbl)(1)					
North America	**$ 11.71**	$ 10.91	$ 10.14	**$ 11.33**	$ 10.11
North Sea	**$ 17.18**	$ 16.85	$ 17.41	**$ 17.02**	$ 16.09
Offshore West Africa	**$ 5.61**	$ 6.08	$ 8.47	**$ 5.85**	$ 9.70
Company average	**$ 11.92**	$ 11.33	$ 11.66	**$ 11.63**	$ 11.48
Natural gas ($/mcf)(1)					
North America	**$ 0.79**	$ 0.79	$ 0.68	**$ 0.79**	$ 0.68
North Sea	**$ 1.47**	$ 1.26	$ 2.92	**$ 1.37**	$ 2.70
Offshore West Africa	**$ 0.36**	$ 1.00	$ 1.37	**$ 0.65**	$ 1.32
Company average	**$ 0.80**	$ 0.80	$ 0.71	**$ 0.80**	$ 0.71
Company average ($/boe)(1)	**$ 8.85**	$ 8.46	$ 8.29	**$ 8.66**	$ 8.17

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

North America

North America crude oil and NGLs production expense per bbl for the six months ended June 30, 2006 increased to $11.33 from $10.11 for the six months ended June 30, 2005 and to $11.71 from $10.14 for the second quarter in 2005, primarily due to higher industry wide service costs. Production expense per bbl in the second quarter of 2006 increased from $10.91 for the prior quarter, also reflecting higher industry wide service costs in all facets of operations, particularly well servicing costs. In addition to these factors, second quarter production expense reflects a product mix with increasing weighting towards higher cost thermal heavy crude oil.

North America natural gas production expense per mcf for the six and three months ended June 30, 2006 increased over the six and three months ended June 30, 2005, but remained unchanged from the prior quarter. The increase from the comparable periods in 2005 was primarily due to continued service and cost pressures seen industry wide.

North Sea

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

Offshore West Africa

Offshore West Africa crude oil production expenses are largely fixed in nature and fluctuated on a per barrel basis from the comparable periods due to changes in production. Production expenses for the six months ended June 30, 2006 compared to the six months ended June 30, 2005 were primarily impacted by the commencement of production from the Baobab Field in August 2005.

MIDSTREAM

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2006**	Mar 31 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
Revenue	**$ 17**	$ 18	$ 17	**$ 35**	$ 38
Production expense	**6**	5	5	**11**	11
Midstream cash flow	**11**	13	12	**24**	27
Depreciation	**2**	2	2	**4**	4
Segment earnings before taxes	$ **9**	$ 11	$ 10	**$ 20**	$ 23

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			Six Months Ended	
	Jun 30 2006	Mar 31 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
Expense ($ millions)	**$ 555**	$ 519	$ 482	**$ 1,074**	$ 954
$/boe(2)	**$ 10.66**	$ 10.56	$ 9.98	**$ 10.62**	$ 9.93

(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, 2006 increased in total and on a boe basis from the comparable periods in 2005 and the prior quarter. The increase in DD&A expense was primarily due to higher volumes, higher finding and development costs associated with natural gas exploration in North America and higher estimated future costs to develop the Company's proved undeveloped reserves in the North Sea.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three Months Ended			Six Months Ended	
	Jun 30 2006	Mar 31 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
Expense ($ millions)	**$ 16**	$ 17	$ 17	**$ 33**	$ 35
$/boe(1)	**$ 0.32**	$ 0.34	$ 0.36	**$ 0.33**	$ 0.37

(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.

ADMINISTRATION EXPENSE

	Three Months Ended			Six Months Ended	
	Jun 30 2006	Mar 31 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
Net expense ($ millions)	**$ 40**	$ 42	$ 42	**$ 82**	$ 77
$/boe(1)	**$ 0.78**	$ 0.85	$ 0.85	**$ 0.81**	$ 0.79

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

Administration expense for the six months ended June 30, 2006 increased in total and on a boe basis from the six months ended June 30, 2005. The increase was primarily due to increased insurance premiums and increased staffing costs.

Administration expense includes compensation expense related to the Share Bonus Plan. The Share Bonus Plan incorporates employee share ownership in the Company while reducing the granting of stock options and the dilution of current Shareholders. Under the plan cash bonuses awarded, based on Company and employee performance, are subsequently used by a trustee to acquire common shares of the Company. The common shares vest to the employee over a three-year period provided the employee does not leave the employment of the Company. If the employee leaves the employment of the Company, the unvested common shares are forfeited under the terms of the plan. For the six months ended June 30, 2006, the Company recognized $14 million of compensation expense under the Share Bonus Plan (June 30, 2005 - $13 million).

STOCK-BASED COMPENSATION (RECOVERY) EXPENSE

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2006**	Mar 31 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
Stock option plan (recovery) expense	**$ (34)**	$ 132	$ 215	**$ 98**	$ 399

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 $98 million ($67 million after tax) stock-based compensation expense for the six months ended June 30, 2006 in connection with the 7% appreciation in the Company's share price, and a $34 million ($21 million after-tax) stock-based compensation recovery as a result of the decrease in the Company's share price in the second quarter of 2006 (Company's share price as at: June 30, 2006 - C$61.72; March 31, 2006 - C$64.90; December 31, 2005 - C$57.63; June 30, 2005 - C$44.40). As required by GAAP, the Company's outstanding stock options are valued 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, 2006 the Company capitalized $66 million in stock-based compensation on the Horizon Project (June 30, 2005 - $45 million). The stock-based compensation liability reflects the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on June 30, 2006. In periods when substantial stock price changes occur, the Company is subject to significant earnings volatility.

For the six months ended June 30, 2006, the Company paid $183 million for stock options surrendered for cash settlement (June 30, 2005 - $110 million).

INTEREST EXPENSE

	Three Months Ended			Six Months Ended	
	Jun 30 2006	Mar 31 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
Interest expense, gross ($ millions)	**$ 69**	$ 58	$ 54	**$ 127**	$ 108
Less: capitalized interest, Horizon Project	**$ 41**	$ 33	$ 14	**$ 74**	$ 25
Interest expense, net	**$ 28**	$ 25	$ 40	**$ 53**	$ 83
$/boe(1)	**$ 0.53**	$ 0.51	$ 0.82	**$ 0.52**	$ 0.87
Average effective interest rate	**5.7%**	5.7%	5.2%	**5.7%**	5.4%

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

Gross interest expense increased from the comparable periods in 2005 and the prior quarter primarily due to higher debt levels. Interest expense also increased from the comparable periods in 2005 due to higher carrying charges. Net interest expense decreased from the comparable periods in 2005 on a total and a boe basis due to the capitalization of construction period interest related to the Horizon Project.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various instruments to manage its commodity price, currency and interest rate exposures. These derivative financial instruments are not used for trading or speculative purposes. Changes in fair value of derivative financial instruments designated as hedges are not recognized in net earnings until such time as the corresponding gains or losses on the related hedged items are also recognized. Changes in fair value of derivative financial instruments not designated as hedges are recognized in the consolidated balance sheets each period with the offset reflected in risk management activities in the statement of earnings.

The Company formally documents all 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. Gains or losses on these contracts are included in risk management activities.

The Company enters into interest rate swap agreements to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. Gains or losses on interest rate swap contracts designated as hedges are included in interest expense. Gains or losses on non-designated interest rate contracts are included in risk management activities.

Gains or losses on the termination or de-designation of financial instruments that have been accounted for as hedges are deferred under other assets or liabilities on the consolidated balance sheets and amortized into net earnings in the period in which the underlying hedged transaction 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 net earnings. Gains or losses on the termination of financial instruments that have not been accounted for as hedges are recognized in net earnings immediately.

RISK MANAGEMENT

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2006**	Mar 31 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
Realized loss (gain)					
Crude oil and NGLs financial instruments	**$ 421**	$ 332	$ 94	**$ 753**	$ 199
Natural gas financial instruments	**(14)**	56	2	**42**	(8)
Interest rate swaps	**-**	-	-	**-**	(8)
	$ 407	$ 388	$ 96	**$ 795**	$ 183
Unrealized loss (gain)					
Crude oil and NGLs financial instruments	**$ (10)**	$ 114	$ 168	**$ 104**	$ 1,075
Natural gas financial instruments	**(12)**	(104)	(50)	**(116)**	36
Interest rate swaps	**(4)**	(2)	1	**(6)**	6
	$ (26)	$ 8	$ 119	**$ (18)**	$ 1,117
Total	**$ 381**	$ 396	$ 215	**$ 777**	$ 1,300

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			Six Months Ended	
	Jun 30 2006	Mar 31 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
Crude oil and NGLs ($/bbl)(1)	**$ 14.18**	$ 12.04	$ 3.58	**$ 13.15**	$ 3.82
Natural gas ($/mcf)(1)	**$ (0.11)**	$ 0.43	$ 0.02	**$ 0.16**	$ (0.03)

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

As effective as commodity 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 Company is required to mark-to-market these non-designated hedges based on prevailing forward commodity prices in effect at the end of each reporting period. Accordingly, the unrealized risk management liability reflects, at June 30, 2006, the implied price differentials for the non-designated hedges for future years. The cash settlement amount of the risk management financial derivative instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their mark-to-market value at June 30, 2006. Due to changes in the crude oil and natural gas forward pricing at June 30, 2006, the Company recorded a net $18 million ($12 million after-tax) unrealized gain on its risk management activities for the six months ended June 30, 2006 (June 30, 2005 - unrealized loss of $1,117 million), including a $26 million ($17 million after-tax) unrealized gain for the three months ended June 30, 2006 (March 31, 2006 - unrealized loss $8 million; June 30, 2005 - unrealized loss $119 million)

In addition to the risk management liability recognized on the balance sheet at June 30, 2006, the net unrecognized liability related to the fair value of derivative financial instruments designated as hedges was $404 million at June 30, 2006 (December 31, 2005 - $990 million).

Details related to outstanding derivative financial instruments at June 30, 2006 are disclosed in note 7 to the Company’s unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2006**	Mar 31 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
Realized foreign exchange loss (gain)	**$ 12**	$ (5)	$ (6)	**$ 7**	$ (18)
Unrealized foreign exchange loss (gain)	**(58)**	10	16	**(48)**	16
	$ (46)	$ 5	$ 10	**$ (41)**	$ (2)

The Company’s results are affected by 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 lower 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 will result in higher revenue from the sale of the Company’s production. Production expenses are also subject to 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 majority of the realized foreign exchange loss in the second quarter of 2006 was the result of the effects of foreign exchange rate fluctuations on working capital items denominated in US dollars or UK pound sterling. The unrealized foreign exchange gain was related to the fluctuation of the Canadian dollar in relation to the US dollar with respect to the US dollar debt and working capital in North America denominated in US dollars, as well as the re-measurement of North Sea future income tax liabilities denominated in UK pound sterling. The Canadian dollar ended the second quarter at US$0.8969 compared to US$0.8159 at June 30, 2005 (March 31, 2006 - US$0.8568).

In order to mitigate a portion of the volatility associated with fluctuations in exchange rates, the Company has designated certain US dollar denominated debt as a hedge against its net investment in US dollar based self-sustaining foreign operations. Accordingly, translation gains and losses on this US dollar denominated debt are included in the foreign currency translation adjustment in Shareholders’ equity in the consolidated balance sheets.

TAXES

($ millions, except income tax rates)	Three Months Ended Jun 30 2006	Mar 31 2006	Jun 30 2005	Six Months Ended Jun 30 2006	Jun 30 2005
Taxes other than income tax					
Current	**$ 59**	$ 35	$ 36	**$ 94**	$ 78
Deferred	**18**	26	4	**44**	4
	$ 77	$ 61	$ 40	**$ 138**	$ 82
Current income tax					
North America	**$ 22**	$ 18	$ 34	**$ 40**	$ 66
North Sea	**(1)**	1	28	**-**	67
Offshore West Africa	**16**	13	4	**29**	7
	$ 37	$ 32	$ 66	**$ 69**	$ 140
Future income tax (recovery) expense	**$ (224)**	$ 268	$ 62	**$ 44**	$ (179)
Effective income tax rate	**(21.9)%**[(2)]	83.9%[(1)]	37.0%	**9.4%**[(1)(2)]	15.8%

(1) 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 in the first quarter of 2006.

(2) 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.

Taxes other than income tax includes current and deferred petroleum revenue tax (“PRT”) and Canadian provincial capital taxes. 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 generated by partnerships, with the related income taxes payable in a subsequent year. 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.

During the first quarter of 2006, the UK government substantively enacted an increase to the supplementary charge on profits from UK North Sea crude oil and natural gas production, resulting in an increase of future tax liabilities of $110 million.

During the second quarter of 2006, the Canadian Federal Government enacted reductions to its corporate tax rates, resulting in a reduction of future income tax liabilities of approximately $277 million.

During the second quarter of 2006, the provinces of Alberta and Saskatchewan enacted reductions to their corporate income tax rates, resulting in a reduction of future tax liabilities of approximately $161 million.

CAPITAL EXPENDITURES[1]

($ millions)	Three Months Ended **Jun 30 2006**	 Mar 31 2006	 Jun 30 2005	Six Months Ended **Jun 30 2006**	 Jun 30 2005
Expenditures on property, plant and equipment					
Net property acquisitions (dispositions)	**$ 7**	$ 12	$ (341)	**$ 19**	$ (339)
Land acquisition and retention	**54**	99	52	**153**	88
Seismic evaluations	**35**	52	20	**87**	61
Well drilling, completion and equipping	**418**	936	306	**1,354**	940
Pipeline and production facilities	**233**	500	283	**733**	715
Total net reserve replacement expenditures	**747**	1,599	320	**2,346**	1,465
Horizon Project:					
Phase 1 construction costs[2]	**680**	616	236	**1,296**	367
Phases 2 and 3 costs	**6**	1	-	**7**	-
Capitalized interest, stock-based compensation and other[2]	**96**	69	39	**165**	123
Total Horizon Project	**782**	686	275	**1,468**	490
Midstream	**6**	3	-	**9**	4
Abandonments[3]	**17**	15	7	**32**	11
Head office	**6**	6	7	**12**	11
Total net capital expenditures	**$ 1,558**	$ 2,309	$ 609	**$ 3,867**	$ 1,981
By segment					
North America	**$ 569**	$ 1,404	$ 110	**$ 1,973**	$ 1,050
North Sea	**149**	138	112	**287**	169
Offshore West Africa	**27**	50	97	**77**	241
Other	**2**	7	1	**9**	5
Horizon Project	**782**	686	275	**1,468**	490
Midstream	**6**	3	-	**9**	4
Abandonments[3]	**17**	15	7	**32**	11
Head office	**6**	6	7	**12**	11
Total	**$ 1,558**	$ 2,309	$ 609	**$ 3,867**	$ 1,981

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

(2) Prior period amounts have been reclassified with respect to stock-based compensation costs.

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

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company focuses 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, 2006 were $3,867 million compared to $1,981 million in the six months ended June 30, 2005. The increase was primarily related to capital expenditures on the Horizon Project and increased activity and cost pressures related to the North America conventional operations. In the six months ended June 30, 2006, the Company drilled a total of 1,031 net wells consisting of 483 natural gas wells, 171 crude oil wells, 309 stratigraphic test and service wells, and 68 wells that were dry. The 309 stratigraphic test and service wells include 103 stratigraphic test wells related to the Horizon Project. This compared to 927 net wells drilled in the six months ended June 30, 2005. The Company achieved an overall success rate of 91% for the six months ended June 30, 2006, excluding stratigraphic test and service wells (June 30, 2005 - 90%).

Net capital expenditures in the second quarter of 2006 were $1,558 million compared to $609 million in the comparable period in 2005 and $2,309 million in the first quarter of 2006. The increase from the second quarter of 2005 was primarily related to capital expenditures on the Horizon Project and increased activity on the North America conventional operations. The decrease from the prior quarter reflects reduced drilling activity due to spring break-up. In the second quarter of 2006, the Company drilled a total of 141 net wells consisting of 43 natural gas wells, 79 crude oil wells, 12 stratigraphic test and service wells, and 7 wells that were dry. The Company achieved an overall success rate of 95% for the second quarter of 2006, excluding stratigraphic test and service wells.

North America

North America accounted for approximately 90% of the total capital expenditures for the six months ended June 30, 2006 compared to approximately 79% in the comparable period in 2005.

During the first half of 2006, the Company targeted 547 net natural gas wells, including 196 wells in Northeast British Columbia, 194 wells in the Northern Plains region, 96 wells in Northwest Alberta, and 61 wells in the Southern Plains region. The Company also targeted 168 net crude oil wells during the first half of 2006. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 56 heavy crude oil wells, 59 Pelican Lake crude oil wells, 26 thermal crude oil wells, and 5 light crude oil wells were drilled. Another 22 light crude oil wells were drilled during the quarter outside of the Northern Plains region. The winter drilling program was negatively impacted by much warmer than normal weather, which precluded timely access to many locations in Northern Alberta and Northeast British Columbia. The Company anticipates that the remaining production locations delayed will largely be tied-in by the end of 2006. In the second quarter of 2006, the Company drilled 48 net wells targeting natural gas and 78 net wells targeting crude oil.

Due to significant changes in relative commodity prices between crude oil and natural gas, the Company has taken the opportunity to utilize its large drilling inventory to maximize value in both the short and long-term. Natural gas pricing has softened significantly in 2006 whereas crude oil pricing remains strong with narrowing Heavy Differentials starting in the second quarter of 2006. The Company will continue to focus on drilling crude oil wells and reduce drilling natural gas wells for the balance of 2006. These natural gas wells will be retained in the Company's prospect inventory, and will be drilled as natural gas commodity prices improve.

As part of the development of the Company's heavy crude oil resources, the Company is continuing with its Primrose thermal projects, which includes the Primrose North expansion project and drilling additional wells in the Primrose South project to augment existing production. To date, the Company has drilled 183 stratigraphic test wells, and has drilled 26 thermal oil wells. First steaming for the Primrose North expansion project commenced in November 2005, resulting in overall thermal production of approximately 77,000 bbl/d in June 2006. Primrose thermal production for the six months ended June 30, 2006 was approximately 55,000 bbl/d.

In 2004, the Company filed a public disclosure document for regulatory approval of its Primrose East project, a new facility located about 15 kilometers from its existing Primrose South steam plant and 25 kilometers from its Wolf Lake central processing facility. The development application was submitted to the Alberta Energy and Utilities Board in January 2006, with potential impacts associated with the use of bitumen as fuel being evaluated in the Environmental Impact Assessment. The Company expects construction to begin in 2007, with first steam scheduled for the end of the first quarter of 2009.

Development of new acreage and secondary recovery conversion projects at Pelican Lake continued as expected through the second quarter of 2006. Drilling consisted of 37 horizontal producing wells with plans to drill 100 additional horizontal wells over the remainder of the year. The pressure response from the polymer flood pilot continued to be positive. The Company commenced installation of a further four polymer skids as part of the commercial polymer flood project. Pelican Lake production averaged approximately 30,000 bbl/d for the second quarter of 2006.

In the third quarter of 2006, the Company's overall drilling activity in North America is expected to be comprised of 106 natural gas wells and 295 crude oil wells excluding stratigraphic and service wells.

Horizon Oil Sands Project

The Horizon Project continued on schedule and on budget with construction 36% complete at quarter end. The project status as at June 30, 2006 was as follows:

- Completed 90% of model reviews;
- Awarded total contracts and purchase orders in excess of $4.4 billion, with a further $400 million in various stages of the tender process;
- Awarded key construction contracts in Extraction, Froth Treatment and Tank Farms;
- Set 140 piperack modules for total progress of 31% complete;
- Site preparation and underground infrastructure substantially completed.

Major activities for the third quarter of 2006 will include:

- Overall detailed engineering to surpass 90%; and
- Commence Tar River Diversion and Raw Water Pond project.

First production of light, sweet Synthetic Crude Oil from Phase 1 construction is targeted to commence in the second half of 2008.

North Sea

In the second quarter, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During the second quarter, 2.8 net wells were drilled, with an additional 1 net well drilling at quarter end.

The development of the Lyell Field progressed on schedule during the quarter. The Lyle Field development comprises the drilling of four net wells, including one injector, and the workover of two existing wells in 2006 and 2007. At its peak, new production of approximately 20,000 boe/d is forecast from the Field.

The Columba E Raw Water Injection project progressed during the quarter, with the completion and delivery of the topside module. The Company plans to drill 2 additional sub-sea water injection wells in 2006 and 2007, resulting in increased production capacity from the existing long reach wells.

Offshore West Africa

At Baobab, 2 additional production wells and one injector well were completed and tied back to the floating production, storage and offtake vessel (“FPSO”), successfully completing the first phase of the development. The drilling rig, having completed the first phase wells below budgeted cost, was released during the second quarter.

At East Espoir, the drilling rig was successfully mobilized to the West Espoir wellhead tower following the completion of two East Espoir infill wells. During the second quarter of 2006, the first well was drilled at West Espoir, with production commencing in the third quarter.

The Company purchased a 90% interest in the Olowi PSC offshore Gabon in October 2005 and received approval of its development plan for this acquisition during the first quarter of 2006. Development plans include an FPSO, handling input from two or three shallow-water producing platforms. During the second quarter of 2006, tenders were received for both the FPSO and rig contracts for the Olowi development. Following engineering design and evaluation of tenders, development is expected to begin in late 2006. First oil is expected late in 2008 at a peak production rate of approximately 20,000 bbl/d.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Jun 30 2006**	Mar 31 2006	Dec 31 2005	Jun 30 2005
Working capital deficit[1]	**$ 1,554**	$ 2,065	$ 1,774	$ 1,340
Long-term debt	**$ 5,004**	$ 4,342	$ 3,321	$ 3,649
Shareholders’ equity				
Share capital	**$ 2,516**	$ 2,500	$ 2,442	$ 2,428
Retained earnings	**6,798**	5,821	5,804	4,655
Foreign currency translation adjustment	**(12)**	(11)	(9)	(4)
Total	**$ 9,302**	$ 8,310	$ 8,237	$ 7,079
Debt to cash flow[2]	**1.0x**	0.9x	0.7x	0.9x
Debt to EBITDA[3]	**0.9x**	0.8x	0.6x	0.8x
Debt to book capitalization[4]	**35.0%**	34.3%	28.7%	35.2%
Debt to market capitalization	**13.1%**	11.1%	9.7%	13.9%
After tax return on average common shareholders’ equity[5]	**29.3%**	20.3%	14.3%	9.9%
After tax return on average capital employed[6]	**20.2%**	14.2%	10.4%	7.5%

(1) Calculated as current assets less current liabilities.

(2) Calculated as current and long-term debt; divided by cash flow from operations for the twelve month trailing period.

(3) Calculated as current and long-term debt; divided by earnings before interest, taxes, depreciation, depletion and amortization, asset retirement obligation accretion, unrealized foreign exchange, stock-based compensation expense and unrealized risk management activities for the twelve month trailing period.

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

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

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

The Company's capital resources at June 30, 2006 consist primarily of cash flow from operations, available credit facilities and access to capital markets. Cash flow from operations is dependent on factors discussed in the Risks and Uncertainties section of the Company's December 31, 2005 annual MD&A**.** The Company's ability to renew existing credit facilities and raise new debt is dependent upon these factors, 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, will be sufficient to sustain its operations and support its growth strategy

At June 30, 2006 the Company had undrawn bank lines of credit of $1,904 million. These credit lines are supported by credit facilities, which if not extended, mature in 2011.

At June 30, 2006, the working capital deficit was $1,554 million and included the current portion of other long-term liabilities of $1,313 million, comprised of stock-based compensation of $539 million and the mark-to-market valuation of non-designated risk management financial derivative instruments of $774 million. The repayment of the stock-based compensation liability is dependant 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 financial derivative instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their mark-to-market value at June 30, 2006.

The Company is committed to maintaining a strong financial position. In the second quarter of 2006, strong operational results and high commodity prices resulted in a debt to book capitalization level of 35.0%. The Company believes it has the necessary financial capacity to complete the Horizon Project while at the same time not compromising delivery of 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, 2006, such as Baobab, Primrose and West Espoir may provide identified growth in production volumes in 2006 through 2008, and may generate incremental free cash flows during this period.

The Company's commodity hedging program was put in place to reduce the risk of volatility in commodity price markets and to underpin the Company's cash flow for its capital expenditures program through the Horizon Project construction period. This expanded program allows for the economic 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 through the use of derivative financial instruments. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. As a result, approximately 75% of budgeted crude oil volumes and approximately 65% of budgeted natural gas volumes have been hedged through the use of collars for the remainder of 2006. In addition, approximately 25% of estimated 2007 crude oil volumes and approximately 60% of estimated 2007 natural gas volumes have been hedged through the use of collars.

Long-term debt

Long-term debt as at June 30, 2006 was $5,004 million. The debt to EBITDA ratio was 0.9x (March 31, 2006 - 0.8x; December 31, 2005 - 0.6x; June 30, 2005 - 0.8x) and the debt to book capitalization was 35.0% (March 31, 2006 - 34.3%; December 31, 2005 - 28.7%; June 30, 2005 - 35.2%) as at June 30, 2006. These ratios are currently at or below the Company's guidelines for balance sheet management of debt to EBITDA of 1.5x to 2.0x and debt to book capitalization of 35% to 45%.

Operating facilities

As at June 30, 2006, the Company had in place unsecured bank credit facilities of $3,456 million, comprised of:

- a $100 million operating demand credit facility;
- a 5-year revolving credit and term loan facility of $1,825 million;
- a 5-year revolving credit and term loan facility of $1,500 million; and
- an unsecured £15 million demand overdraft credit facility related to the Company's North Sea operations.

During the second quarter, the syndicated revolving credit and term loan facilities were renegotiated and are fully revolving for a period of five years maturing June 2011. 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 addition to the outstanding debt, letters of credit and financial guarantees aggregating $124 million were outstanding at June 30, 2006.

Medium-term notes

In January 2006, the Company issued $400 million of debt securities maturing January 2013, bearing interest at 4.50%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these securities, the Company has $1.6 billion remaining on its $2 billion 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.

US dollar debt securities

In June 2005, the Company filed a short form prospectus that allows for the issue of up to US$2 billion of debt securities in the United States until July 2007, of which no securities have been issued to date. If issued, these securities will bear interest as determined at the date of issuance.

Share capital

As at June 30, 2006, there were 537,155,000 common shares and 30,110,000 stock options outstanding. As at July 28, 2006, the Company had 537,296,000 common shares outstanding.

In January 2006, the Company announced the renewal of its Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange and the New York Stock Exchange to purchase, during the 12-month period beginning January 24, 2006 and ending January 23, 2007, up to 26,852,545 common shares or 5% of the common shares of the Company then outstanding on the date of the announcement. As at June 30, 2006, the Company had purchased 390,000 common shares at an average price of $56.93 per common share, for a total cost of $22 million. Subsequent to June 30, 2006, the Company purchased an additional 45,000 common shares at an average price of $60.85 per common share, for a total cost of $3 million.

In February 2006, the Board of Directors set the regular quarterly dividend at $0.075 per common share (2005 - $0.059 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.

Contractual obligations

In the normal course of business, the Company has entered into various contractual arrangements and commitments that will have an impact on the Company's future operations. These contractual obligations and commitments primarily relate to debt repayments, operating leases relating to office space and offshore production and storage vessels, and firm commitments for gathering, processing and transmission services, as well as expenditures relating to asset retirement obligations. The Company has not entered into any contracts that would require consolidation under CICA Accounting Handbook, AcG-15, Consolidation of Variable Interest Entities. The following table summarizes the Company's commitments as at June 30, 2006:

($ millions)		Remaining 2006		2007		2008		2009		2010		Thereafter
Product transportation and pipeline(1)	$	107	$	184	$	181	$	128	$	117	$	1,120
Offshore equipment operating lease	$	25	$	49	$	50	$	49	$	49	$	172
Offshore drilling	$	76	$	158	$	55	$	11	$	11	$	4
Asset retirement obligations(2)	$	50	$	4	$	4	$	4	$	7	$	3,303
Long-term debt(3)	$	-	$	160	$	35	$	35	$	-	$	3,252
Other(4)	$	32	$	67	$	27	$	35	$	36	$	11

(1) In 2005, 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) Represents 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.

(3) No debt repayments are reflected for the bank credit facilities due to the extendable nature of the facilities.

(4) Consists of future expenditures related primarily to office lease, electricity and crude oil processing.

In February 2005, the Board of Directors approved the construction costs for Phase 1 of the Horizon Project, which are budgeted to be $6.8 billion, including a contingency fund of $700 million, with cumulative spending of $2.6 billion to June 30, 2006, $1.3 billion targeted to be incurred in the remainder of 2006 and $2.9 billion targeted to be incurred in 2007 and 2008.

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

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, 2005.

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 production volumes during the second quarter of 2006. Each separate item in the sensitivity analysis shows the effect of an increase 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	$ 105	$ 0.20	$ 73	$ 0.14
Including financial derivatives	$ 75	$ 0.14	$ 52	$ 0.10
Natural gas – AECO C$0.10/mcf(2)				
Excluding financial derivatives	$ 39	$ 0.07	$ 26	$ 0.05
Including financial derivatives	$ 8 - 13	$ 0.01 - 0.02	$ 2 - 6	$ 0.00 - 0.01
Volume changes				
Crude oil – 10,000 bbl/d	$ 138	$ 0.26	$ 75	$ 0.14
Natural gas – 10 mmcf/d	$ 16	$ 0.03	$ 6	$ 0.01
Foreign currency rate change				
$0.01 change in C$ in relation to US$(2)	$ 72 - 74	$ 0.13 - 0.14	$ 27	$ 0.05
Interest rate change - 1%	$ 15	$ 0.03	$ 15	$ 0.03

(1) The sensitivities are calculated based on 2006 second quarter results excluding mark-to-market gains (losses) on risk management activities.

(2) For details of outstanding financial instruments in place, refer to note 7 of the Company's unaudited interim consolidated financial statements.

OTHER OPERATING HIGHLIGHTS

NETBACK ANALYSIS

($/boe)[1]	Three Months Ended Jun 30 2006	Mar 31 2006	Jun 30 2005	Six Months Ended Jun 30 2006	Jun 30 2005
Sales price[2]	**$ 50.36**	$ 46.30	$ 43.05	**$ 48.39**	$ 41.51
Royalties	**5.80**	6.44	5.85	**6.11**	5.64
Production expense[3]	**8.85**	8.46	8.29	**8.66**	8.17
Netback	**35.71**	31.40	28.91	**33.62**	27.70
Midstream contribution[3]	**(0.23)**	(0.25)	(0.25)	**(0.24)**	(0.28)
Administration	**0.78**	0.85	0.85	**0.81**	0.79
Interest, net	**0.53**	0.51	0.82	**0.52**	0.87
Realized risk management loss	**7.81**	7.90	1.98	**7.85**	1.91
Realized foreign exchange loss (gain)	**0.25**	(0.12)	(0.14)	**0.07**	(0.19)
Taxes other than income tax - current	**1.13**	0.71	0.76	**0.93**	0.81
Current income tax - North America	**0.42**	0.36	0.71	**0.39**	0.69
Current income tax - North Sea	**(0.01)**	0.01	0.59	**-**	0.70
Current income tax - Offshore West Africa	**0.30**	0.27	0.08	**0.29**	0.07
Cash flow	**$ 24.73**	$ 21.16	$ 23.51	**$ 23.00**	$ 22.33

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

(2) Including transportation costs and excluding risk management activities.

(3) Excluding intersegment elimination.

FINANCIAL STATEMENTS

Consolidated balance sheets

(millions of Canadian dollars, unaudited)	**Jun 30 2006**	Dec 31 2005
ASSETS		
Current assets		
Cash and cash equivalents	**$ 15**	$ 18
Accounts receivable and other	**1,507**	1,546
Future income tax	**447**	487
	1,969	2,051
Property, plant and equipment	**22,351**	19,694
Other long-term assets	**115**	107
	$ 24,435	$ 21,852
LIABILITIES		
Current liabilities		
Accounts payable	**$ 792**	$ 573
Accrued liabilities	**1,418**	1,781
Current portion of other long-term liabilities (note 3)	**1,313**	1,471
	3,523	3,825
Long-term debt (note 2)	**5,004**	3,321
Other long-term liabilities (note 3)	**1,506**	1,434
Future income tax	**5,100**	5,035
	15,133	13,615
SHAREHOLDERS' EQUITY		
Share capital (note 5)	**2,516**	2,442
Retained earnings	**6,798**	5,804
Foreign currency translation adjustment	**(12)**	(9)
	9,302	8,237
	$ 24,435	$ 21,852

Commitments (note 8)

Consolidated statements of earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended Jun 30 2006	Three Months Ended Jun 30 2005	Six Months Ended Jun 30 2006	Six Months Ended Jun 30 2005
Revenue	**$ 2,717**	$ 2,164	**$ 5,089**	$ 4,157
Less: royalties	**(302)**	(283)	**(618)**	(542)
Revenue, net of royalties	**2,415**	1,881	**4,471**	3,615
Expenses				
Production	**467**	405	**886**	794
Transportation	**78**	66	**159**	133
Depletion, depreciation and amortization	**557**	484	**1,078**	958
Asset retirement obligation accretion (note 3)	**16**	17	**33**	35
Administration	**40**	42	**82**	77
Stock-based compensation (recovery) expense (note 3)	**(34)**	215	**98**	399
Interest, net	**28**	40	**53**	83
Risk management activities (note 7)	**381**	215	**777**	1,300
Foreign exchange (gain) loss	**(46)**	10	**(41)**	(2)
	1,487	1,494	**3,125**	3,777
Earnings (loss) before taxes	**928**	387	**1,346**	(162)
Taxes other than income tax	**77**	40	**138**	82
Current income tax expense (note 4)	**37**	66	**69**	140
Future income tax (recovery) expense (note 4)	**(224)**	62	**44**	(179)
Net earnings (loss)	**$ 1,038**	$ 219	**$ 1,095**	$ (205)
Net earnings (loss) per common share (note 6)				
Basic and diluted	**$ 1.93**	$ 0.41	**$ 2.04**	$ (0.38)

Consolidated statements of retained earnings

(millions of Canadian dollars, unaudited)	Six Months Ended Jun 30 2006	Six Months Ended Jun 30 2005
Balance – beginning of period	**$ 5,804**	$ 4,922
Net earnings (loss)	**1,095**	(205)
Dividends on common shares (note 5)	**(81)**	(62)
Purchase of common shares under normal course issuer bid (note 5)	**(20)**	-
Balance – end of period	**$ 6,798**	$ 4,655

Consolidated statements of cash flows

(millions of Canadian dollars, unaudited)	Three Months Ended Jun 30 2006	Three Months Ended Jun 30 2005	Six Months Ended Jun 30 2006	Six Months Ended Jun 30 2005
Operating activities				
Net earnings (loss)	**$ 1,038**	$ 219	**$ 1,095**	$ (205)
Non-cash items				
Depletion, depreciation and amortization	**557**	484	**1,078**	958
Asset retirement obligation accretion	**16**	17	**33**	35
Stock-based compensation (recovery) expense	**(34)**	215	**98**	399
Unrealized risk management activities	**(26)**	119	**(18)**	1,117
Unrealized foreign exchange (gain) loss	**(58)**	16	**(48)**	16
Deferred petroleum revenue tax	**18**	4	**44**	4
Future income tax (recovery) expense	**(224)**	62	**44**	(179)
Deferred charges	**7**	(33)	**(8)**	(38)
Abandonment expenditures	**(17)**	(7)	**(32)**	(11)
Net change in non-cash working capital	**(47)**	135	**(358)**	(87)
	1,230	1,231	**1,928**	2,009
Financing activities				
Issue (repayment) of bankers' acceptances	**781**	(614)	**1,400**	(341)
Issue of medium-term notes	**-**	400	**400**	400
Issue of common shares on exercise of stock options	**3**	3	**13**	5
Dividends on common shares	**(40)**	(30)	**(72)**	(57)
Purchase of common shares	**(22)**	-	**(22)**	-
Net change in non-cash working capital	**4**	4	**6**	20
	726	(237)	**1,725**	27
Investing activities				
Expenditures on property, plant and equipment	**(1,543)**	(950)	**(3,837)**	(2,318)
Net proceeds on sale of property, plant and equipment	**2**	348	**2**	348
Net expenditures on property, plant and equipment	**(1,541)**	(602)	**(3,835)**	(1,970)
Investment in other assets	**-**	(60)	**-**	(60)
Net change in non-cash working capital	**(412)**	(342)	**179**	(3)
	(1,953)	(1,004)	**(3,656)**	(2,033)
Increase (decrease) in cash	**3**	(10)	**(3)**	3
Cash – beginning of period	**12**	41	**18**	28
Cash – end of period	**$ 15**	$ 31	**$ 15**	$ 31
Interest paid	**$ 57**	$ 47	**$ 109**	$ 91
Taxes paid				
Taxes other than income tax	**$ 52**	$ 49	**$ 133**	$ 159
Current income tax	**$ 80**	$ 12	**$ 253**	$ 123

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, 2005. 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 financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2005.

Comparative figures

Certain figures provided for the prior year have been reclassified to conform to the presentation adopted in 2006.

2. LONG–TERM DEBT

		Jun 30 2006		Dec 31 2005
Bank credit facilities				
Bankers' acceptances	**$**	**1,522**	$	122
Medium-term notes		**925**		525
Senior unsecured notes (2006 and 2005 – US$93 million)		**104**		108
US dollar debt securities (2006 and 2005 – US$2,200 million)		**2,453**		2,566
	$	**5,004**	$	3,321

Bank credit facilities

As at June 30, 2006, the Company had in place unsecured bank credit facilities of $3,456 million, comprised of:

- a $100 million operating demand credit facility;
- a 5-year revolving credit and term loan facility of $1,825 million;
- a 5-year revolving credit and term loan facility of $1,500 million; and
- an unsecured £15 million demand overdraft credit facility related to the Company's North Sea operations.

During the second quarter, the syndicated revolving credit and term loan facilities were renegotiated and are fully revolving for a period of five years maturing June 2011. 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.

The weighted average interest rate of the bank credit facilities outstanding at June 30, 2006, was 4.8% (December 31, 2005 - 4.0%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $124 million were outstanding at June 30, 2006.

Medium-term notes

In January 2006, the Company issued $400 million of debt securities maturing January 2013, bearing interest at 4.50%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these securities, the Company has $1.6 billion remaining on its $2 billion 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.

US dollar debt securities

In June 2005, the Company filed a short form prospectus that allows for the issue of up to US$2 billion of debt securities in the United States until July 2007, of which no securities have been issued to date. If issued, these securities will bear interest as determined at the date of issuance.

3. OTHER LONG–TERM LIABILITIES

	Jun 30 2006	Dec 31 2005
Asset retirement obligations	**$ 1,095**	$ 1,112
Stock-based compensation	**809**	891
Risk management (note 7)	**867**	885
Other	**48**	17
	2,819	2,905
Less: current portion	**1,313**	1,471
	$ 1,506	$ 1,434

Asset retirement obligations

At June 30, 2006, the Company's total estimated undiscounted cost to settle its asset retirement obligations was approximately $3,372 million (December 31, 2005 - $3,325 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 6.8%. A reconciliation of the discounted asset retirement obligations is as follows:

	Six Months Ended Jun 30, 2006	Year Ended Dec 31, 2005
Balance – beginning of period	**$ 1,112**	$ 1,119
Liabilities incurred	**5**	47
Liabilities settled	**(32)**	(46)
Asset retirement obligation accretion	**33**	69
Revision of estimates	**-**	(56)
Foreign exchange	**(23)**	(21)
Balance – end of period	**$ 1,095**	$ 1,112

The Company's pipelines have indeterminant lives and therefore the fair values of the related asset retirement obligations cannot be reasonably determined. The asset retirement obligations for these assets will be recorded in the years in which the lives of the assets are determinable.

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, 2006	Year Ended Dec 31, 2005
Balance – beginning of period	**$ 891**	$ 323
Stock-based compensation provision	**98**	723
Current period payment for options surrendered	**(183)**	(227)
Transferred to common shares	**(63)**	(29)
Capitalized to Horizon Project	**66**	101
Balance – end of period	**809**	891
Less: current portion of stock-based compensation	**539**	629
	$ 270	$ 262

4. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Six Months Ended	
	Jun 30 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
Current income tax – North America	**$ 22**	$ 34	**$ 40**	$ 66
Current income tax – North Sea	**(1)**	28	**-**	67
Current income tax – Offshore West Africa	**16**	4	**29**	7
Current income tax expense	**37**	66	**69**	140
Future income tax (recovery) expense	**(224)**	62	**44**	(179)
Income tax (recovery) expense	**$ (187)**	$ 128	**$ 113**	$ (39)

A significant portion of the Company's North America taxable income is generated by partnerships. Current income taxes are incurred on the partnerships' taxable income in the year following their inclusion in the Company's consolidated net earnings. North America current income tax is dependant upon the nature and amount of capital expenditures incurred in Canada.

During the first quarter of 2006, the UK government substantively enacted an increase to the supplementary charge on profits from UK North Sea crude oil and natural gas production, resulting in an increase of future tax liabilities of $110 million.

During the second quarter of 2006, the Canadian Federal Government enacted reductions to its corporate tax rates, resulting in a reduction of future income tax liabilities of approximately $277 million.

During the second quarter of 2006, the provinces of Alberta and Saskatchewan enacted reductions to their corporate income tax rates, resulting in a reduction of future tax liabilities of approximately $161 million.

5. SHARE CAPITAL

Issued Common shares	Six Months Ended Jun 30, 2006 Number of shares (thousands)	Amount
Balance – beginning of period	**536,348**	**$ 2,442**
Issued upon exercise of stock options	**1,197**	**13**
Previously recognized liability on stock options exercised for common shares	**-**	**63**
Purchase of common shares under Normal Course Issuer Bid	**(390)**	**(2)**
Balance – end of period	**537,155**	**$ 2,516**

Normal course issuer bid

In January 2006, the Company announced the renewal of its Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange and the New York Stock Exchange to purchase, during the 12-month period beginning January 24, 2006 and ending January 23, 2007, up to 26,852,545 common shares or 5% of the common shares of the Company then outstanding on the date of the announcement. As at June 30, 2006, the Company had purchased 390,000 common shares at an average price of $56.93 per common share, for a total cost of $22 million. Retained earnings was reduced by $20 million, representing the excess of the purchase price of the common shares over their stated value. Subsequent to June 30, 2006, the Company purchased an additional 45,000 common shares at an average price of $60.85 per common share, for a total cost of $3 million.

Dividend policy

In February 2006, the Board of Directors set the regular quarterly dividend at $0.075 per common share (2005 - $0.059 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, 2006 Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of period	**30,510**	**$ 17.79**
Granted	**5,171**	**$ 60.40**
Exercised for common shares	**(1,197)**	**$ 9.75**
Surrendered for cash settlement	**(3,442)**	**$ 12.39**
Forfeited	**(932)**	**$ 33.01**
Outstanding – end of period	**30,110**	**$ 25.57**
Exercisable – end of period	**9,809**	**$ 13.65**

6. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended		Six Months Ended	
	Jun 30 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
Weighted average common shares outstanding (thousands) – basic and diluted	**537,351**	536,689	**537,188**	536,597
Net earnings (loss) – basic and diluted	**$ 1,038**	$ 219	**$ 1,095**	$ (205)
Net earnings (loss) per common share - basic and diluted	**$ 1.93**	$ 0.41	**$ 2.04**	$ (0.38)

7. 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 used for trading or other speculative purposes.

The estimated fair values of non-designated financial derivatives were comprised as follows:

	Six Months Ended Jun 30, 2006		Year Ended Dec 31, 2005	
Asset (liability)	**Risk management mark-to-market**	**Deferred revenue**	Risk management mark-to-market	Deferred revenue
Balance – beginning of period	**$ (877)**	**$ (8)**	$ 66	$ (26)
Net cost of outstanding put options	**448**	**-**	190	-
Net change in fair value of outstanding derivative financial instruments	**12**	**-**	(943)	-
Amortization of deferred revenue	**-**	**6**	-	18
	(417)	**(2)**	(687)	(8)
Add: Put premium financing obligations(1)	**(448)**	**-**	(190)	-
Balance – end of period	**(865)**	**(2)**	(877)	(8)
Less: current portion	**772**	**2**	834	8
	$ (93)	**$ -**	$ (43)	$ -

(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 risk management liability.

Net losses (gains) from risk management activities for the periods ended June 30 were as follows:

	Three Months Ended		Six Months Ended	
	Jun 30 2006	Jun 30 2005	**Jun 30 2006**	Jun 30 2005
Net realized risk management loss	**$ 407**	$ 96	**$ 795**	$ 183
Net unrealized risk management mark-to-market (gain) loss	**(26)**	119	**(18)**	1,117
	$ 381	$ 215	**$ 777**	$ 1,300

As at June 30, 2006, the net unrecognized liability related to the estimated fair values of derivative financial instruments designated as hedges was $404 million (December 31, 2005 - $990 million).

The Company had the following net financial derivatives outstanding as at June 30, 2006:

	Remaining term			Volume	Average price			Index
Crude oil								
Price collars	Jul 2006	–	Dec 2006	160,000 bbl/d	US$38.17	–	US$48.16	WTI
	Jul 2006	–	Dec 2006	90,000 bbl/d	US$45.00	–	US$77.93	WTI
	Jul 2006	–	Dec 2006	22,000 bbl/d	C$46.53	–	C$58.67	WTI
	Jan 2007	–	Dec 2007	50,000 bbl/d	US$60.00	–	US$90.63	WTI
	Jan 2007	–	Dec 2007	50,000 bbl/d	US$65.00	–	US$84.52	WTI
Put options	Jul 2006	–	Jul 2006	38,000 bbl/d			US$40.00	WTI
	Aug 2006	–	Dec 2006	51,000 bbl/d			US$50.00	WTI
	Jan 2007	–	Dec 2007	100,000 bbl/d			US$45.00	WTI
	Jan 2007	–	Dec 2007	100,000 bbl/d			US$60.00	WTI
	Jan 2008	–	Dec 2008	50,000 bbl/d			US$55.00	WTI
Brent differential swaps	Jul 2006	–	Dec 2006	25,000 bbl/d			US$1.29	WTI/Dated Brent
	Jan 2007	–	Dec 2007	50,000 bbl/d			US$1.34	WTI/Dated Brent

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

	Q3 2006	Q4 2006	Q1 2007	Q2 2007	Q3 2007	Q4 2007	Q1 2008	Q2 2008	Q3 2008	Q4 2008
Cost ($ millions)	US$6	US$5	US$82	US$83	US$84	US$84	US$14	US$14	US$15	US$15

	Remaining term			Volume	Average price			Index
Natural gas								
AECO collars[1]	Jul 2006	–	Oct 2006	555,000 GJ/d	C$5.50	–	C$7.09	AECO
	Jul 2006	–	Oct 2006	150,000 GJ/d	C$6.00	–	C$9.53	AECO
	Jul 2006	–	Dec 2006	100,000 GJ/d	C$7.00	–	C$14.16	AECO
	Nov 2006	–	Mar 2007	700,000 GJ/d[2]	C$7.50	–	C$18.80	AECO
	Nov 2006	–	Mar 2007	325,000 GJ/d	C$6.00	–	C$14.68	AECO
	Nov 2006	–	Mar 2007	100,000 GJ/d	C$7.00	–	C$11.63	AECO
	Apr 2007	–	Oct 2007	500,000 GJ/d	C$6.00	–	C$10.13	AECO
	Apr 2007	–	Oct 2007	320,000 GJ/d[3]	C$7.00	–	C$8.25	AECO
	Nov 2007	–	Mar 2008	500,000 GJ/d	C$6.00	–	C$16.39	AECO
	Nov 2007	–	Mar 2008	400,000 GJ/d	C$7.00	–	C$14.08	AECO

(1) Subsequent to June 30, 2006, the Company entered into 300,000 GJ/d of C$5.00 – C$7.10 AECO collars for the period September 2006 to October 2006.

(2) Subsequent to June 30, 2006, the Company unwound 400,000 GJ/d of the C$7.50 - C$18.80 AECO collars and entered into 400,000 GJ/d of C$8.50 - C$11.22 AECO collars for the period November 2006 to March 2007.

(3) Subsequent to June 30, 2006, the Company entered into an additional 180,000 GJ/d of C$7.00 - C$8.21 AECO collars for the period April 2007 to October 2007.

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

The Company has also entered into natural gas physical sales contracts for 325,000 GJ/d at a fixed price of C$9.17 per GJ for the period January to March 2007.

	Remaining term			Amount ($ millions)	Fixed rate	Floating rate
Interest rate						
Swaps – fixed to floating	Jul 2006	–	Oct 2012	US$350	5.45%	LIBOR[1] + 0.81%
	Jul 2006	–	Dec 2014	US$350	4.90%	LIBOR[1] + 0.38%
Swaps – floating to fixed	Jul 2006	–	Mar 2007	C$4	7.36%	CDOR[2]

(1) London Interbank Offered Rate

(2) Canadian Deposit Overnight Rate

8. COMMITMENTS

The Company has committed to certain payments as follows:

	Remaining 2006	2007	2008	2009	2010	Thereafter
Product transportation and pipeline[1]	$ 107	$ 184	$ 181	$ 128	$ 117	$ 1,120
Offshore equipment operating lease	$ 25	$ 49	$ 50	$ 49	$ 49	$ 172
Offshore drilling	$ 76	$ 158	$ 55	$ 11	$ 11	$ 4
Asset retirement obligations[2]	$ 50	$ 4	$ 4	$ 4	$ 7	$ 3,303
Other[3]	$ 32	$ 67	$ 27	$ 35	$ 36	$ 11

(1) The Company has 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) Represents 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.

(3) Consists of future expenditures related primarily to office lease, electricity and crude oil processing.

In February 2005, the Board of Directors approved the construction costs for Phase 1 of the Horizon Project, which are budgeted to be $6.8 billion, including a contingency fund of $700 million, with cumulative spending of $2.6 billion to June 30, 2006, $1.3 billion targeted to be incurred in the remainder of 2006 and $2.9 billion targeted to be incurred in 2007 and 2008.

9. 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	
	2006	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005
Segmented revenue	**2,082**	1,719	**3,902**	3,263	**377**	381	**697**	775	**255**	57	**482**	101
Less: royalties	**(295)**	(281)	**(605)**	(538)	**-**	-	**(1)**	(1)	**(7)**	(2)	**(12)**	(3)
Segmented revenue, net of royalties	**1,787**	1,438	**3,297**	2,725	**377**	381	**696**	774	**248**	55	**470**	98
Segmented expenses												
Production	**356**	288	**668**	563	**87**	104	**168**	205	**19**	9	**41**	17
Transportation	**83**	70	**171**	140	**5**	5	**8**	11	**-**	-	**-**	-
Depletion, depreciation and amortization	**448**	396	**863**	780	**62**	72	**122**	154	**45**	14	**89**	20
Asset retirement obligation accretion	**9**	7	**17**	16	**7**	10	**15**	19	**-**	-	**1**	-
Realized risk management activities	**316**	76	**633**	135	**91**	20	**162**	48	**-**	-	**-**	-
Total segmented expenses	**1,212**	837	**2,352**	1,634	**252**	211	**475**	437	**64**	23	**131**	37
Segmented earnings (loss) before the following	**575**	601	**945**	1,091	**125**	170	**221**	337	**184**	32	**339**	61
Non-segmented expenses												
Administration												
Stock-based compensation (recovery) expense												
Interest, net												
Unrealized risk management activities												
Foreign exchange (gain) loss												
Total non-segmented expenses												
Earnings (loss) before taxes												
Taxes other than income tax												
Current income tax expense												
Future income tax (recovery) expense												
Net earnings (loss)												

(millions of Canadian dollars, unaudited)	Midstream				Inter-segment elimination and other				Total			
	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	
	2006	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005
Segmented revenue	**17**	17	**35**	38	**(14)**	(10)	**(27)**	(20)	**2,717**	2,164	**5,089**	4,157
Less: royalties	**-**	-	**-**	-	**-**	-	**-**	-	**(302)**	(283)	**(618)**	(542)
Segmented revenue, net of royalties	**17**	17	**35**	38	**(14)**	(10)	**(27)**	(20)	**2,415**	1,881	**4,471**	3,615
Segmented expenses												
Production	**6**	5	**11**	11	**(1)**	(1)	**(2)**	(2)	**467**	405	**886**	794
Transportation	**-**	-	**-**	-	**(10)**	(9)	**(20)**	(18)	**78**	66	**159**	133
Depletion, depreciation and amortization	**2**	2	**4**	4	**-**	-	**-**	-	**557**	484	**1,078**	958
Asset retirement obligation accretion	**-**	-	**-**	-	**-**	-	**-**	-	**16**	17	**33**	35
Realized risk management activities	**-**	-	**-**	-	**-**	-	**-**	-	**407**	96	**795**	183
Total segmented expenses	**8**	7	**15**	15	**(11)**	(10)	**(22)**	(20)	**1,525**	1,068	**2,951**	2,103
Segmented earnings (loss) before the following	**9**	10	**20**	23	**(3)**	-	**(5)**	-	**890**	813	**1,520**	1,512
Non-segmented expenses												
Administration									**40**	42	**82**	77
Stock-based compensation (recovery) expense									**(34)**	215	**98**	399
Interest, net									**28**	40	**53**	83
Unrealized risk management activities									**(26)**	119	**(18)**	1,117
Foreign exchange (gain) loss									**(46)**	10	**(41)**	(2)
Total non-segmented expenses									**(38)**	426	**174**	1,674
Earnings (loss) before taxes									**928**	387	**1,346**	(162)
Taxes other than income tax									**77**	40	**138**	82
Current income tax expense									**37**	66	**69**	140
Future income tax (recovery) expense									**(224)**	62	**44**	(179)
Net earnings (loss)									**1,038**	219	**1,095**	(205)

Net additions to property, plant and equipment

	Six Months Ended					
	Jun 30, 2006			Jun 30, 2005		
	Cash Expenditures	**Non-Cash/ Fair Value Changes(1)**	**Capitalized Costs**	Cash Expenditures	Non-Cash/ Fair Value Changes(1)	Capitalized Costs
North America	**$ 1,973**	**$ 5**	**$ 1,978**	$ 1,050	$ (168)	$ 882
North Sea	**287**	**-**	**287**	169	-	169
Offshore West Africa	**77**	**-**	**77**	241	31	272
Other	**9**	**-**	**9**	5	-	5
Horizon Project(2)	**1,468**	**-**	**1,468**	490	-	490
Midstream	**9**	**-**	**9**	4	-	4
Head office	**12**	**-**	**12**	11	-	11
	$ 3,835	**$ 5**	**$ 3,840**	$ 1,970	$ (137)	$ 1,833

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

(2) Cash expenditures also include capitalized interest and stock-based compensation.

	Property, plant and equipment		Total assets	
	Jun 30 2006	Dec 31 2005	**Jun 30 2006**	Dec 31 2005
Segmented assets				
North America	**$ 15,426**	$ 14,310	**$ 16,882**	$ 15,939
North Sea	**1,757**	1,681	**2,016**	1,950
Offshore West Africa	**1,234**	1,253	**1,326**	1,371
Other	**22**	13	**37**	30
Horizon Project	**3,635**	2,169	**3,715**	2,239
Midstream	**208**	203	**390**	258
Head office	**69**	65	**69**	65
	$ 22,351	$ 19,694	**$ 24,435**	$ 21,852

Capitalized interest

Beginning in 2005, following the Board of Directors' approval of the Horizon Project, the Company commenced capitalization of construction period interest based on costs incurred and the Company's cost of borrowing. Interest capitalization will cease once construction is substantially complete and the Horizon Project is available for its intended use. For the six months ended June 30, 2006, pre-tax interest of $74 million was capitalized to the Horizon Project (June 30, 2005 - $25 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, 2006:

Interest coverage (times)	
Net earnings[(1)]	13.6x
Cash flow from operations[(2)]	23.1x

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

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

CORPORATE INFORMATION

Officers

Allan P. Markin*
Chairman of the Board

N. Murray Edwards*
Vice-Chairman of the Board

John G. Langille*
Vice-Chairman of the Board

Steve W. Laut*
President & Chief Operating Officer

Douglas A. Proll*
Chief Financial Officer &
Senior Vice-President, Finance

Réal M. Cusson*
Senior Vice-President, Marketing

Réal J.H. Doucet*
Senior Vice-President, Oil Sands

Allen M. Knight*
Senior Vice-President, International & Corporate Development

Tim S. McKay*
Senior Vice-President, Operations

Lyle G. Stevens*
Senior Vice-President, Exploitation

Jeff W. Wilson*
Senior Vice-President, Exploration

Mary-Jo E. Case*
Vice-President, Land

Corey B. Bieber
Vice-President, Investor Relations

Wayne M. Chorney
Vice-President, Development Operations

William R. Clapperton
Vice-President, Regulatory, Stakeholder & Environmental Affairs

Gordon M. Coveney
Vice-President, Exploration - East

Randall S. Davis*
Vice-President, Financial Accounting & Controls

Larry C. Galea
Vice-President, Operations Planning

Jerry W. Harvey
Vice-President, Commercial Operations

Peter J. Janson
Vice-President, Engineering Integration

Terry J. Jocksch
Vice-President, Exploitation - East

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Vice-President, Utilities & Offsites

Philip A. Keele
Vice-President, Mining

Cameron S. Kramer
Vice-President, Field Operations

Richard P. Lock
Vice-President, Bitumen Production

León Miura
Vice-President, Upgrading

S. John Parr
Vice-President, Production - East

David A. Payne
Vice-President, Exploitation - West

Bill R. Peterson
Vice-President, Production - West

John C. Puckering
Vice-President, Site Development

Sheldon L. Schroeder
Vice-President, Project Control

Ken W. Stagg
Vice-President, Exploration, West

Steve C. Suche
Vice-President,
Information & Corporate Services

Lynn M. Zeidler
Vice-President,
Horizon Construction Management

Kimberly I. McKay
Treasurer

Bruce E. McGrath
Corporate Secretary

*Management Committee

Stock Listing

Toronto Stock Exchange
Trading Symbol – CNQ and CNQ.U*

*denotes trading in US funds

New York Stock Exchange
Trading Symbol – CNQ

Registrar and Transfer Agent

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
New York, New York

Board of Directors

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