CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES STRONG QUARTERLY OPERATING RESULTS

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In commenting on first quarter 2006 results, Canadian Natural's Chairman, Allan Markin stated, "The execution of our defined plan for profitable growth continues on track. In the first quarter we executed a record drilling program in a challenging environment due to unseasonably warm weather and limits in the availability of rigs and services, all the while achieving a 90% overall success rate. On our major projects we saw first production from Primrose North which reached 15,000 bbl/d during the quarter, we received government approval of the Olowi Field development plan offshore Gabon, and we started seeing positive production results from the waterflood and polymer floods at Pelican Lake. At the Horizon Project, our team continues to execute and as a result, we remain slightly ahead of project targets with all critical path items remaining on track. We are extremely proud of the work of our people in meeting the challenges that we face on a daily basis, both on the conventional side of the business and on the Horizon Project."

John Langille, Vice-Chairman, commented "Much wider than normal heavy crude oil differentials combined with a decrease in natural gas pricing and a stronger Canadian dollar reduced average selling prices received for our products in the first quarter. Heavy oil differentials have improved markedly in recent weeks, due in part to our heavy oil marketing strategy and in particular our participation in certain pipeline reversals which access new markets. Today, based on current strip pricing we would expect to generate cash flow in the range of $5.4 billion to $5.6 billion, as forecast in our 2006 budget. This strong cash flow, combined with the continued management of our capital costs in this very heated environment means that we will still expect to exit 2006 with an exceptionally strong balance sheet, with debt to cash flow targeted under 1x and debt to book capitalization targeted in the low 30% range."

Canadian Natural's President and Chief Operating Officer, Steve Laut, in commenting on the Company's quarter end and winter drilling program stated, "The 2006 winter drilling program was challenging in terms of managing both the impacts of unusual weather patterns and general cost pressures. The abnormally warm weather resulted in the majority of our drilling program being executed in March, which is more typically expected in January. The results of the drilling program were excellent; however the timing of the drilling and tie-ins has left at the end of the quarter 70 mmcf/d of natural gas unconnected to sales lines when compared to plan. Due to cost pressures, the Company has made the strategic decision to maintain its planned capital expenditure level which will result in a slight reduction in overall drilling activity. This reduction will be focused primarily on natural gas activity as a result of the significant change in relative pricing between crude oil and natural gas. On the other hand, at the Horizon Project, the warm winter weather has allowed us to achieve progress ahead of plan. To date we have awarded in excess of C$4 billion in contracts compared to a target construction cost of C$6.8 billion, providing a greater degree of cost certainty in this highly inflationary environment."

HIGHLIGHTS

($ millions, except as noted)	Three Months Ended **Mar 31 2006**	Dec 31 2005	Mar 31 2005
Net earnings (loss)	**$ 57**	$ 1,104	$ (424)
per common share, basic[1]	**$ 0.11**	$ 2.06	$ (0.79)
Adjusted net earnings from operations[2]	**$ 268**	$ 601	$ 380
per common share, basic[1]	**$ 0.50**	$ 1.12	$ 0.71
Cash flow from operations[3]	**$ 1,039**	$ 1,490	$ 1,009
per common share, basic[1]	**$ 1.93**	$ 2.78	$ 1.88
Capital expenditures, net of dispositions	**$ 2,309**	$ 1,679	$ 1,372
Debt to book capitalization[4]	**34%**	29%	37%
Daily production, before royalties			
Natural gas (mmcf/d)	**1,436**	1,423	1,455
Crude oil and NGLs (bbl/d)	**323,662**	340,268	287,803
Equivalent production (boe/d)	**563,027**	577,505	530,316

(1) Restated to reflect two-for-one common share split in May 2005.

(2) 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").

(3) 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.

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

- Quarterly cash flow of $1,039 billion, neutral compared to Q1/05 and a 30% decrease from Q4/05 due to lower price realizations and, as expected, lower sales volumes from Primrose and high netback International operations.
- Quarterly net earnings of $57 million compared to a loss of $424 million in Q1/05. First quarter net earnings included:
  - A charge of $110 million for the effect of the UK statutory tax rate changes on future income tax liabilities.
  - A charge of $88 million after tax for revaluation of the stock option liability to reflect stock price appreciation during the quarter.
- Strong quarterly adjusted net earnings from operations of $268 million.
- Strong balance sheet with debt to book capitalization exiting what has historically been our highest capital quarter and lowest cash flow quarter at 34% and debt to EBITDA at 0.8x compared with 37% and 0.9x, respectively, at the end of Q1/05.
- Quarterly production volumes 6% higher than Q1/05.
- North America natural gas production in Q1/06 increased 1% over Q4/05 but decreased 1% from Q1/05 reflecting the impact of the delays in the 2006 winter drilling program where more wells were drilled later in the season than originally planned.
- Completed a record first quarter drilling program of 593 net wells, excluding stratigraphic test and service wells, with a 90% success ratio, reflecting Canadian Natural's strong, predictable, low-risk asset base.
- Maintained our strong undeveloped conventional land base in Canada of 11.0 million net acres - a key asset in today's highly competitive industry.

- Continued production improvements at Pelican Lake Field arising from new drilling activity and expansion of enhanced oil recovery strategies. Pelican Lake crude oil production averaged 29 mbbl/d during the quarter, up 62% or 11 mbbl/d from Q1/05 and up 1 mbbl/d from Q4/05. During the quarter, the Company installed the first two polymer skids as part of the commercial polymer flood.
- Completed drilling at East Espoir and are currently mobilizing the drilling rig to the West Espoir tower, which targets production of 13 mboe/d later this year.
- The Development Plan for the Olowi Field was approved by the Government of Gabon for this offshore crude oil development targeting first production in the last quarter of 2008.
- The Horizon Oil Sands Project remained on budget and ahead of schedule, with site preparation and construction work benefiting from a warmer and drier than normal first quarter.
- The first quarter dividend was increased 25% from $0.06 per common share to $0.075 per common share commencing with the April 1, 2006 dividend payment.

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 our ongoing growth and development within these core regions. Land inventories are maintained to enable continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs. Further, the Company maintains large project inventories and production diversification among each of the commodities it produces; namely natural gas, light / medium crude oil and NGLs, Pelican Lake crude oil, primary heavy crude oil and thermal heavy crude oil. A large diversified project portfolio enables the effective allocation of capital to higher return opportunities.

Cost pressures and significant changes in relative commodity prices have allowed Canadian Natural the opportunity to utilize its large drilling inventory to maximize value in the short and long-term. Natural gas pricing has softened significantly in early 2006, whereas crude oil prices have remained strong and heavy crude oil differentials have narrowed from over 45% of WTI in the first quarter of 2005 to the current differential of approximately 29% of WTI range in Q2/06 resulting in record heavy oil pricing at the wellhead.

As a result of increased drilling and completion costs, Canadian Natural has made the strategic decision to maintain its planned capital expenditure level which will result in a slight reduction in overall drilling activity. This reduction will be focused primarily on natural gas activity as a result of the significant change in relative pricing between crude oil and natural gas.

As a result of this strategic decision, Canadian Natural will drill 150 fewer natural gas wells than originally planned in 2006, a 13% reduction, while maintaining crude oil drilling at planned 2006 levels. This will allow Canadian Natural to maximize near term returns in a high crude oil price environment, and reduce overall activity in a highly inflationary cost environment.

Activity by core region

	Net undeveloped land as at Mar 31, 2006 (thousands of net acres)	Drilling activity Three months ended Mar 31, 2006 (net wells)
Canadian conventional		
Northeast British Columbia	**2,040**	**192**
Northwest Alberta	**1,516**	**84**
Northern Plains	**6,221**	**264**
Southern Plains	**687**	**45**
Southeast Saskatchewan	**89**	**3**
	10,553	**588**
In Situ Oil Sands	**406**	**194**
Horizon Oil Sands Project	**116**	**103**
United Kingdom North Sea	**352**	**2**
Offshore West Africa	**207**	**3**
	11,634	**890**

Drilling activity (number of wells)

	Three Months Ended Mar 31			
	2006		2005	
	Gross	**Net**	Gross	Net
Crude oil	**106**	**92**	130	109
Natural gas	**537**	**440**	380	338
Dry	**65**	**61**	64	56
Subtotal	**708**	**593**	574	503
Stratigraphic test / service wells	**297**	**297**	188	188
Total	**1,005**	**890**	762	691
Success rate (excluding stratigraphic test / service wells)		**90%**		89%

North America natural gas

	Quarterly Results		
	Q1/06	Q4/05	Q1/05
Natural gas production (mmcf/d)	**1,411**	1,402	1,430
Net wells targeting natural gas	**499**	295	386
Net successful wells drilled	**440**	279	338
Success rate	**88%**	95%	88%

- Q1/06 natural gas production represented a 1% increase over the previous quarter despite warmer than normal weather influencing the winter drilling program. As such the Company drilled more wells in March than in January. Despite these challenges Canadian Natural completed the majority of its winter drilling program with a high success rate. However, the shift in the timing of drilling from early in the season to later in the season significantly delayed tie-ins of many of these new wells.

- As a result of the back loaded drilling program, approximately 70 mmcf/d of natural gas production remained behind pipe at the end of the quarter. Some locations will be tied-in during the second, third and fourth quarters, however it is estimated that 20-30 mmcf/d will remain stranded until freeze up in late Q4/06 or early Q1/07.

- High success rates reflect Canadian Natural's low-risk exploitation approach and high quality land base. The Q1/06 drilling program represented an active program across the Company's core regions. In Northeast British Columbia 191 net wells targeting natural gas were drilled, while in Northwest Alberta 80 net wells were drilled, including 37 Cardium targets. In Northern and Southern Plains, a total of 26 coal bed methane, 23 shallow natural gas and 179 conventional net wells were drilled.

- The results of our Q1 natural gas program met expectations in terms of reserve and rate expectations, and were within our economic criteria. However, with service costs continuing to escalate and relatively strong crude oil prices compared to natural gas prices, the Company has made the strategic decision to drill 150 fewer (13% less than originally planned) natural gas wells in 2006.

- This reduction in planned drilling activity and the delays in getting our Q1/06 drilling program tied in have resulted in a small adjustment of less than 2% to the mid point of our annual corporate guidance for natural gas production volumes reflecting the strength and quality of our natural gas drilling program.

- Planned drilling activity for the second quarter of 2006 includes 66 wells targeting natural gas.

North America crude oil and NGLs

	Quarterly Results		
	Q1/06	Q4/05	Q1/05
Crude oil and NGLs production (bbl/d)	**222,955**	230,263	209,125
Net wells targeting crude oil	**90**	191	114
Net successful wells drilled	**88**	185	106
Success rate	**98%**	97%	93%

- During the quarter, drilling activity included 33 wells targeting heavy crude oil and 15 wells targeting light crude oil. The majority of the wells, 79 of 90 net wells, targeting crude oil during Q1/06 were drilled in the Northern Plains core region.
- The Primrose Field development continued with the drilling of 20 net wells in Q1/06. Production from the pads at Primrose is subject to the cycling of steam injection and crude oil production. Due to normal cycling activities as well as the addition of new well pads from Primrose North, average thermal crude oil production levels in Q1/06 were 8 mbbl/d or 14% lower than Q4/05 but slightly better than originally anticipated. Production volumes are expected to increase in Q2/06 and will ramp up to approximately 75 mbbl/d in Q3/06 resulting in peak production from the area as the crude oil processing plant approaches its design capacity.
- 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 mbbl/d to 120 mbbl/d ,as well as, the construction of a steam generation plant and new pad drilling which will add production gains targeted at 30 mbbl/d in 2009.

- At Pelican Lake the development of new acreage and secondary recovery conversion projects continued as planned. Drilling consisted of 22 horizontal producing wells, 13 stratigraphic wells and four water source wells. During the remainder of 2006, the Company plans to drill an additional 117 wells at Pelican Lake. Production increased from 28 mbbl/d in Q4/05 to 29 mbbl/d in Q1/06. The North Brintnell waterflood conversion project was expanded by 744 acres. Pressure response data from the polymer flood pilot remains on track with expectations. Also at the project, Canadian Natural commenced installation of the first two polymer skids as part of the commercial polymer flood project.
- Planned drilling activity for the second quarter includes 87 net crude oil wells.

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 oil upgrader to process its conventional heavy and thermal heavy crude oil production. The Scoping Study for the Canadian Natural Upgrader was initiated during the quarter. The terms of reference for this study will evaluate end product alternatives, location, technology, gasification and integration with existing assets. Recommendations are expected in late 2006 / 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 with a current forecast start-up date in 2012.

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		
	Q1/06	Q4/05	Q1/05
Total crude oil production (bbl/d)			
North Sea	**60,802**	66,798	71,139
Offshore West Africa	**39,905**	43,207	7,539
Total natural gas production (mmcf/d)			
North Sea	**17**	15	23
Offshore West Africa	**8**	6	2
Net wells targeting crude oil	**4.2**	5.9	2.9
Net successful wells drilled	**4.2**	5.0	2.3
Success rate	**100%**	85%	79%

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 Q1/06, 2.8 net wells, including 0.9 net water injectors, were drilled with an additional 3.9 net wells drilling over quarter end. Production levels were in line with expectations and reflected growth at Columba D Terrace and Ninian Field and expected temporary curtailments at the Lyell Field and the Columba E Terrace as well as temporary restrictions at B-Block and Playfair Fields.
- The prolific new well drilled into the Columba D Terrace during Q4/05 declined in line with expectation. In February, additional pay was perforated in this well which yielded a 6 mbbl/d initial uplift, net to Canadian Natural, and a water injector to support this developed production was completed during the quarter. At quarter end, an early positive waterflood re-pressuring response was observed.
- On the Ninian Field, the platform rig completed a Ninian Central producer, which was brought onstream towards the end of the quarter at a rate of 8.7 mbbl/d, net to Canadian Natural.
- Construction of the subsea water injection pump at Columba E Terrace progressed during the quarter. This will be tied into 2 additional subsea water injection wells that will be drilled late in 2006. This repressurization of the pool, combined with artificial lift will result in increased productive capacity from the existing long reach wells.
- Plans for the further development of the Lyell Field progressed, which entails drilling 4 net wells and working over 2 existing net wells in 2006/7. At its plateau, new production of approximately 20 mboe/d is forecast from this field.

Offshore West Africa

- During Q1/06, 2.3 net wells were drilled with an additional 0.6 net wells drilling over quarter end. Production levels were ahead of expectation, primarily due to early delivery of planned wells at both Baobab and East Espoir. Some curtailment of production was experienced due to planned outages to tie these wells in.
- At Baobab, peak crude oil production reached 52 mbbl/d (33 mmbbl/d net to Canadian Natural) during the quarter and averaged 25 mbbl/d net to Canadian Natural. The eighth production well continues to experience production restrictions due to limitations resulting from monitoring sand screen effectiveness. During the first quarter two additional production wells were drilled resulting in an initial uplift of 10 mbbl/d net to Canadian Natural. Production is expected to remain constant at Q1 average levels until the sand screen effectiveness issues are resolved on the eighth producer and as cleanup continues on the new wells.
- Net production at East Espoir was in line with Q4/05, and averaged 15 mboe/d during Q1/06 following the build-up of production from the infill drilling program. The infill drilling program consisted of 4 wells, with the 2 remaining wells now completed and the field currently producing at a record level of 20 mbbl/d, net to Canadian Natural.
- At Espoir, drilling is now complete on the East Espoir Field with the rig being moved from East Espoir tower to the West Espoir tower in Q2. The West Espoir project continues on time and on budget with first crude oil production expected in the second half of 2006, ramping up to 13 mboe/d when fully developed. During the quarter, the West Espoir drilling tower, which will facilitate development drilling of this reservoir, was installed and the drilling conductors were driven to depth.
- Following the review of 3-D seismic previously acquired on Block CI-400, located offshore Côte d'Ivoire, the Company has relinquished its rights.
- In Gabon, a development plan comprising a Floating Production Storage and Offtake Vessel and four drilling towers was approved for execution by the Government in the first quarter of 2006. The development is expected to commence in late 2006 with first production targeted for late 2008 to reach a plateau rate of 20 mbbl/d. The permit comprises a 90% interest in the production sharing agreement for the block containing the Olowi Field, located about 20 kilometres from the Gabonese coast and in 30 metres water depth. Olowi has been delineated by the drilling of 15 wells on the block and potentially contains as much as 500 million barrels of 34º API light crude oil originally in place. The crude oil reservoir is overlain by a large gas cap with potentially one trillion cubic feet of gas originally in place.

Horizon Oil Sands Project ("Horizon Project")

- Phase 1 of the Horizon Project continues on plan and on budget. First production of 110 mbbl/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 mbbl/d following completion of Phase 2 in 2010. Production levels of 232 mbbl/d are targeted for 2012, following completion of Phase 3 construction. The Company is currently evaluating the opportunity to combine Phase 2 and 3 for a targeted joint operational date of 2011.
- As a result of the mild winter weather conditions experienced in early 2006, the progress on major milestones, a key component in achieving critical path success, are slightly ahead of schedule.
- 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 as 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 proven technologies for mining, extraction and upgrading processes.
- Construction capital costs for Phase 1 of the Horizon Project are budgeted at $6.8 billion, including a contingency fund of $700 million, with $1.9 billion spent to date, $2.0 billion targeted to be incurred in the remainder of 2006 and $2.9 billion targeted to be incurred in 2007 and 2008.
- During the first quarter of 2006, major milestones were achieved sooner than expected and safety performance remained ahead of target. The placement of the four coke drums, each weighing 400 tonnes, was completed. The first piperack modules were also placed on foundations and we continue to place additional modules on an ongoing basis. The new $40m^3$ hydraulic shovel is being commissioned and sufficient overburden is expected to be removed to enable the start of construction of the Ore Preparation Plant during the second quarter.
- The quarterly update for the project is as follows:

Project status summary

	Mar 31, 2006		Jun 30, 2006
	Actual	Plan	Plan
Phase 1 - Work progress (cumulative)	**26%**	22%	31%
Phase 1 - Construction capital spending (cumulative)	**27%**	29%	39%

Accomplished During the First Quarter

Detailed Engineering

- Completed 60% of detailed engineering model reviews in all areas.
- Completed hazard and operability reviews for all plants, a major hurdle to ensure scope changes are not required.

Procurement

- Awarded in excess of C$200 million of contracts and purchase orders in the quarter bringing awards-to-date to over C$4 billion, with a further C$600 million in various stages of the tender process.
- Awarded key Mechanical contracts for Bitumen Production.
- Completed "Contractor Open House" sessions across Canada to attract new contractors and skilled trades people to the oil sands industry. Over 300 contractors participated in these sessions.
- Completed transport of naphtha reactor to site from the rail staging area south of Fort McMurray.
- Site assembly of gas oil and distillate reactors on track for completion in the fourth quarter.
- Issued purchase orders for long lead equipment (cokers and reactors) for Phase 2 and 3 upgrading.

Modularization

- Delivered 164 oversized loads to site, out of approximately 1,500 total loads to be delivered during the construction period.

Construction

- Site safety performance remains ahead of benchmarked targets.
- Delivered four coke drums to site as planned and erected on schedule.
- Started setting of piperack modules on foundations.
- Commissioned operation of permanent water and waste water treatment plants.
- Main administration building, security building, plant maintenance shop and fire hall were completed and occupied.
- Mine overburden removal has moved 10.8 million bcm (bank cubic meters) compared to a plan of 10.4 million bcm with commissioning of a new 40m^3 hydraulic shovel planned for the second quarter.
- Completed 98% of site preparation and undergrounds.

Second Quarter 2006 Milestones

- Overall detailed engineering to surpass 80% completion.
- Occupancy of the second of three camps.
- New 40m^3 shovel expected to be in operation for mine overburden removal.
- Occupation of Mine Overburden Administration and Maintenance Facility to take place.
- Ore Preparation Plant site turnover by Mining to Bitumen Production.

MARKETING

	Quarterly Results		
	Q1/06	Q4/05	Q1/05
Crude oil and NGLs pricing			
WTI[1] benchmark price (US$/bbl)	**$ 63.53**	$ 60.04	$ 49.90
Lloyd Blend Heavy oil differential from WTI (%)	**45%**	40%	39%
Corporate average pricing before risk management (C$/bbl)	**$ 43.79**	$ 46.38	$ 39.81
Natural gas pricing			
AECO benchmark price (C$/GJ)	**$ 8.82**	$ 11.07	$ 6.35
Corporate average pricing before risk management (C$/mcf)	**$ 8.30**	$ 11.67	$ 6.68

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

- Despite having averaged 45% of WTI during Q1/06, heavy crude oil differentials have narrowed significantly in the second quarter coincident with the reversal of the Corsicana and Spearhead Pipelines, a third party outage, as well as the start of the high demand paving season. The Company has committed to 25 mbbl/d of new pipeline capacity on the reversal of the Corsicana Pipeline which carries heavy crude oil from the terminus of the current pipeline sales lines at Patoka, Illinois to the east Texas refining complex near Nederland. This pipeline was commissioned in late March with Canadian Natural’s first sales deliveries reaching Nederland on April 6, 2006.
- During the first quarter, the Company contributed approximately 156 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.

- The price for natural gas was 20% lower than in the previous quarter, reflecting the warmest month of January on record for North America. The demand in the first quarter was unusually weak, which resulted in the highest gas inventory position at the end of March since 1991. Weather and relative value to crude oil pricing will greatly impact the pricing level over the next several months.

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 - currently producing in excess of 590 mboe/d, comprised of approximately 43% natural gas and 57% 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 $2.7 billion of unused bank lines available at March 31, 2006.
  - Strong balance sheet - with a debt to book capitalization ratio of 34%, debt to cash flow of 0.9x, debt to EBITDA of 0.8x and shareholders' equity of $8.3 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 and approximately 55% of budgeted 2006 natural gas volumes have been hedged through the use of collars for the remainder of 2006. Details of current hedge positions may be found on the Company's website at:

  http://www.cnrl.com/investor_info/corporate_guidance/hedging.html.
- 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 March 31, 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 $8 million ($5 million after tax) unrealized loss on its risk management activities for the three months ended March 31, 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.
- Effective January 1, 2006, the UK government substantively enacted an increase to the supplementary charge on profits from UK North Sea crude oil and natural gas production from 10% to 20%, increasing the Company's effective income tax rate in the North Sea to approximately 50%. The supplementary charge excludes any deduction for financing costs. The Company's opening future income tax liability was increased by $110 million as at January 1, 2006, with respect to this tax rate change.
- The Normal Course Issuer Bid has been extended to January 2007, allowing for the repurchase of up to 26.9 million shares through the facilities of the Toronto Stock Exchange and the New York Stock Exchange. To date, no common shares have been repurchased under this program.
- In January 2006, Canadian Natural issued C$400 million of 7-year notes at a rate of 4.50%
- In February 2006, the Board of Directors approved an increase in the quarterly dividend to $0.075 per common share from $0.06 per common share. The 25% increase recognizes the stability of Canadian Natural's cash flow and provides a further return to shareholders. This is the sixth consecutive year in which the Company has paid a dividend and the fifth consecutive year of increase in the distribution paid to its shareholders. The increased dividend became effective with the quarterly payment paid on April 1, 2006.

Q2/06 OUTLOOK

The Company has revised its annual production guidance and currently expects 2006 production levels before royalties to average 1,448 to 1,516 mmcf/d of natural gas and 338 to 370 mbbl/d of crude oil and NGLs. Q2/06 production guidance before royalties is 1,461 to 1,520 mmcf/d of natural gas and 326 to 348 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/. Commodity hedge information is regularly updated and may similarly be found at http://www.cnrl.com/investor_info/corporate_guidance/hedging.html.

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 three months ended March 31, 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"). 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 operation, 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 net of royalties is presented for information purposes only.

The following discussion refers primarily to the Company's financial results for the three months ended March 31, 2006 in relation to the first quarter of 2005 and the prior quarter. The accompanying tables form an integral part of this MD&A. This MD&A is dated May 3, 2006.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

		Three Months Ended	
	Mar 31 2006	Dec 31 2005	Mar 31 2005[1]
Revenue, before royalties	**$ 2,372**	$ 3,032	$ 1,993
Net earnings (loss)	**$ 57**	$ 1,104	$ (424)
Per common share – basic	**$ 0.11**	$ 2.06	$ (0.79)
– diluted	**$ 0.11**	$ 2.06	$ (0.79)
Adjusted net earnings from operations[2]	**$ 268**	$ 601	$ 380
Per common share – basic	**$ 0.50**	$ 1.12	$ 0.71
– diluted	**$ 0.50**	$ 1.12	$ 0.71
Cash flow from operations[3]	**$ 1,039**	$ 1,490	$ 1,009
Per common share – basic	**$ 1.93**	$ 2.78	$ 1.88
– diluted	**$ 1.93**	$ 2.78	$ 1.88
Capital expenditures, net of dispositions	**$ 2,309**	$ 1,679	$ 1,372

(1) Restated to reflect a two-for-one common share split in May 2005.

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

		Three Months Ended	
($ millions)	***Mar 31 2006***	*Dec 31 2005*	*Mar 31 2005*
Net earnings (loss) as reported	***$ 57***	*$ 1,104*	*$ (424)*
Stock-based compensation, net of tax[(a)]	***88***	*75*	*125*
Unrealized risk management loss (gain), net of tax[(b)]	***5***	*(583)*	*679*
Unrealized foreign exchange loss, net of tax[(c)]	***8***	*5*	*-*
Effect of statutory tax rate changes on future income tax liabilities[(d)]	***110***	*-*	*-*
Adjusted net earnings from operations	***$ 268***	*$ 601*	*$ 380*

(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 are recorded in net earnings in the period the legislation is substantively enacted. Effective January 1, 2006, the UK government substantively enacted an increase to the supplementary charge on profits from UK North Sea crude oil and natural gas production from 10% to 20%, increasing the Company's effective income tax rate in the North Sea to approximately 50%. The supplementary charge excludes any deduction for financing costs. The Company's future income tax liability was increased by $110 million with respect to this tax rate change.

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

	Three Months Ended		
($ millions)	***Mar 31 2006***	*Dec 31 2005*	*Mar 31 2005*
Net earnings (loss)	***$ 57***	*$ 1,104*	*$ (424)*
Non-cash items:			
Depletion, depreciation and amortization	***521***	*550*	*474*
Asset retirement obligation accretion	***17***	*16*	*18*
Stock-based compensation	***132***	*125*	*184*
Unrealized risk management activities	***8***	*(825)*	*998*
Unrealized foreign exchange loss	***10***	*5*	*-*
Deferred petroleum revenue tax	***26***	*1*	*-*
Future income tax expense (recovery)	***268***	*514*	*(241)*
Cash flow from operations	***$ 1,039***	*$ 1,490*	*$ 1,009*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

For the three months ended March 31, 2006, the Company reported net earnings of $57 million compared to a net loss of $424 million for the three months ended March 31, 2005 and net earnings of $1,104 million for the three months ended December 31, 2005. Net earnings for the three months ended March 31, 2006 included unrealized after-tax expenses of $211 million related to the effects of a UK statutory tax rate change on future income tax liabilities, stock-based compensation expense, foreign exchange losses and risk management activities. This compared to $804 million of net after-tax expenses for the three months ended March 31, 2005 and $503 million of net after-tax income for the three months ended December 31, 2005. Excluding these items, adjusted net earnings from operations for the three months ended March 31, 2006 decreased by 29% to $268 million from $380 million for the three months ended March 31, 2005, primarily due to higher realized losses from risk management activities that offset higher realized crude oil and natural gas pricing net of differentials and a stronger Canadian dollar. Adjusted net earnings from operations decreased by 55% from $601 million for the three months ended December 31, 2005, primarily due to lower realized crude oil prices net of differentials and lower realized natural gas prices.

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, fluctuations in foreign exchange rates, and changes in the corporate income tax rates in countries where the Company operates.

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 55% of budgeted natural gas volumes have been hedged through the use of collars for the remainder of 2006.

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 March 31, 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 March 31, 2006.

Due to the changes in crude oil and natural gas forward pricing, the Company recorded a net $8 million ($5 million after-tax) unrealized loss on its risk management activities for the three months ended March 31, 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 $132 million ($88 million after-tax) stock-based compensation expense for the three months ended March 31, 2006 in connection with the 13% appreciation in the Company's share price during the first quarter of 2006 (Company's share price as at: March 31, 2006 - C$64.90; December 31, 2005 - C$57.63; March 31, 2005 - C$34.18). 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 March 31, 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 three months ended March 31, 2006 increased slightly to $1,039 million from $1,009 million for the three months ended March 31, 2005, and decreased 30% from $1,490 million for the three months ended December 31, 2005. The decrease in cash flow from operations from the prior quarter reflects primarily the impact of the widening heavy crude oil differentials, lower natural gas prices and a strengthening Canadian dollar relative to the US dollar, partially offset by a decrease in realized risk management losses. As a result of seasonal demands, reversals of the Corsicana and Spearhead pipelines and third party outages, the heavy oil differential has narrowed. This is expected to result in improvements in the Company's realized crude oil pricing.

Total production before royalties averaged 563,027 boe/d for the three months ended March 31, 2006, up 6% from 530,316 boe/d for the three months ended March 31, 2005, but decreased 3% from 577,505 boe/d for the three months ended December 31, 2005.

OPERATING HIGHLIGHTS

	Three Months Ended		
	Mar 31 2006	Dec 31 2005	Mar 31 2005
Crude oil and NGLs ($/bbl)[1]			
Sales price[2]	**$ 43.79**	$ 46.38	$ 39.81
Royalties	**3.48**	3.89	3.39
Production expense	**11.33**	10.33	11.30
Netback	**$ 28.98**	$ 32.16	$ 25.12
Natural gas ($/mcf)[1]			
Sales price[2]	**$ 8.30**	$ 11.67	$ 6.68
Royalties	**1.70**	2.30	1.30
Production expense	**0.80**	0.76	0.69
Netback	**$ 5.80**	$ 8.61	$ 4.69
Barrels of oil equivalent ($/boe)[1]			
Sales price[2]	**$ 46.30**	$ 56.08	$ 39.94
Royalties	**6.44**	8.01	5.42
Production expense	**8.46**	7.93	8.04
Netback	**$ 31.40**	$ 40.14	$ 26.48

(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		
	Mar 31 2006	Dec 31 2005	Mar 31 2005
WTI benchmark price (US$/bbl)	**$ 63.53**	$ 60.04	$ 49.90
Dated Brent benchmark price (US$/bbl)	**$ 61.80**	$ 56.93	$ 47.71
Dated Brent differential from WTI (%)	**3%**	5%	4%
Differential to LLB blend (US$/bbl)	**$ 28.70**	$ 24.09	$ 19.26
LLB blend differential from WTI (%)	**45%**	40%	39%
Condensate benchmark price (US$/bbl)	**$ 63.63**	$ 60.41	$ 51.45
NYMEX benchmark price (US$/mmbtu)	**$ 9.10**	$ 12.83	$ 6.31
AECO benchmark price (C$/GJ)	**$ 8.82**	$ 11.07	$ 6.35
US / Canadian dollar average exchange rate (US$)	**0.8660**	0.8523	0.8152

World crude oil prices remained strong in the first quarter of 2006 despite increasing crude oil inventories, due to:

- continued demand growth, particularly in China and the United States;
- ongoing geopolitical uncertainties in Iran, Nigeria, Iraq and Venezuela; and
- production losses in the Gulf of Mexico from hurricanes Katrina and Rita.

West Texas Intermediate ("WTI") averaged US$63.53 per bbl for the three months ended March 31, 2006, an increase of 27% compared to US$49.90 per bbl for the three months ended March 31, 2005, and an increase of 6% from US$60.04 per bbl for the three months ended December 31, 2005.

While crude oil benchmark prices continued to increase during the first quarter of 2006, the full benefit of higher WTI pricing does not get completely reflected in the Company's crude oil price realizations. The positive impact of higher WTI prices on the Company's crude oil production was hampered by the widening heavy crude oil differentials, which increased 49% to average US$28.70 per bbl for the three months ended March 31, 2006 from US$19.26 per bbl for the three months ended March 31, 2005 and increased 19% from US$24.09 per bbl for the three months ended December 31, 2005. The widening in the heavy crude oil differential from the first quarter of 2005 was primarily due to increased demand for lighter barrels of crude oil. The stronger demand for higher yield light barrels of crude oil increased the benchmark light crude oil prices such as WTI, resulting in wider heavy oil differentials. Heavy crude oil differentials continued to widen from the fourth quarter of 2005 to the first quarter of 2006 due to both increased demand for lighter barrels of crude oil and normal winter seasonal decline in demand for heavy crude oil. The Company's crude oil price realizations were also impacted by the effect of a strengthening Canadian dollar relative to the US dollar. A strengthening in the Canadian dollar reduces the Canadian dollar sales price the Company receives for its crude oil production as crude oil prices are based on US dollar denominated benchmarks.

The Company anticipates a narrowing of the heavy crude oil differential in the second quarter of 2006 due to seasonal demands, the reversals of the Corsicana and Spearhead pipelines and a third party outage that is expected to reduce supply.

NYMEX natural gas prices averaged US$9.10 per mmbtu for the three months ended March 31, 2006, up 44% from US$6.31 per mmbtu for the three months ended March 31, 2005, and down 29% from US$12.83 per mmbtu for the three months ended December 31, 2005. AECO natural gas pricing moved directionally with NYMEX. The increase from the first quarter of 2005 to the first quarter of 2006 was primarily a response to increasing benchmark crude oil prices. The decrease from the fourth quarter of 2005 reflects mild weather experienced during the first quarter of 2006, which resulted in reduced demand and higher natural gas inventory levels.

PRODUCT PRICES[1]

	Three Months Ended		
	Mar 31 2006	Dec 31 2005	Mar 31 2005
Crude oil and NGLs ($/bbl)[2]			
North America	**$ 34.16**	$ 37.96	$ 32.28
North Sea	**$ 68.05**	$ 66.88	$ 59.56
Offshore West Africa	**$ 65.23**	$ 60.19	$ 62.34
Company average	**$ 43.79**	$ 46.38	$ 39.81
Natural gas ($/mcf)[2]			
North America	**$ 8.39**	$ 11.79	$ 6.73
North Sea	**$ 2.38**	$ 3.40	$ 3.52
Offshore West Africa	**$ 5.59**	$ 5.13	$ 7.67
Company average	**$ 8.30**	$ 11.67	$ 6.68
Company average ($/boe)[2]	**$ 46.30**	$ 56.08	$ 39.94
Percentage of revenue (excluding midstream revenue)			
Crude oil and NGLs	**53%**	48%	54%
Natural gas	**47%**	52%	46%

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

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

Company realized crude oil prices increased 10% to average $43.79 per bbl for the three months ended March 31, 2006, up from $39.81 per bbl for the three months ended March 31, 2005 and decreased 6% from $46.38 per bbl for the three months ended December 31, 2005. The increase from the first quarter of 2005 was primarily due to higher benchmark world crude oil prices and an increased proportion of crude oil and NGLs sales coming from Offshore West Africa, offset by wider heavy crude oil differentials in North America and a stronger Canadian dollar. The decrease from the prior quarter was primarily due to higher diluent pricing, wider Canadian light crude oil and heavy crude oil differentials and the strengthening Canadian dollar.

The Company's realized natural gas price increased 24% to average $8.30 per mcf for the three months ended March 31, 2006, up from $6.68 per mcf for the three months ended March 31, 2005, primarily in response to increasing benchmark crude oil prices. The Company's realized natural gas price decreased 29% from $11.67 per mcf in the prior quarter primarily as a result of mild weather experienced during the first quarter of 2006, which resulted in reduced demand and higher natural gas inventory levels.

North America

North America realized crude oil prices increased 6% to average $34.16 per bbl for the three months ended March 31, 2006, up from $32.28 per bbl for the three months ended March 31, 2005, but decreased 10% from $37.96 per bbl for the three months ended December 31, 2005. The increase from the first quarter of 2005 was primarily due to higher benchmark world crude oil prices offset by wider heavy crude oil differentials and a stronger Canadian dollar. The decrease from the prior quarter was primarily due to higher diluent pricing, and wider Canadian light crude oil and heavy crude oil differentials.

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 first quarter, the Company contributed approximately 156,000 bbl/d of heavy crude oil blends to the Western Canadian Select ("WCS") stream, a new blend of up to 10 different crude oil streams. WCS resembles a Bow River type crude with distillation cuts approximating a natural heavy crude oil with premium quality asphalt characteristics and has an API of 19-22 degrees. Volumes of the new blend are expected to grow, with the potential to become a new benchmark for North America markets in addition to WTI. 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 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 Corsicana Pipeline, which carries crude oil to the Gulf of Mexico with a view to expanding markets for its heavy crude oil. The Corsicana 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 Corsicana pipeline occurred on April 6, 2006.

North America realized natural gas prices increased 25% to average $8.39 per mcf for the three months ended March 31, 2006, up from $6.73 per mcf for the three months ended March 31, 2005. The increase from the first quarter of 2005 to the first quarter of 2006 was primarily in response to increasing benchmark crude oil prices. Realized natural gas prices for the first quarter of 2006 decreased 29% from $11.79 per mcf for the three months ended December 31, 2005 as a result of mild weather experienced during the first quarter of 2006, which resulted in reduced demand and higher natural gas inventory levels.

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

	Three Months Ended		
	Mar 31 2006	Dec 31 2005	Mar 31 2005
Wellhead Price[(1)(2)]			
Light/medium crude oil and NGLs (C$/bbl)	**$ 58.21**	$ 61.33	$ 50.46
Pelican Lake crude oil (C$/bbl)	**$ 31.60**	$ 34.86	$ 31.74
Primary heavy crude oil (C$/bbl)	**$ 25.91**	$ 31.00	$ 25.46
Thermal heavy crude oil (C$/bbl)	**$ 23.60**	$ 28.84	$ 24.69
Natural gas (C$/mcf)	**$ 8.39**	$ 11.79	$ 6.73

(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 $68.05 per bbl for the three months ended March 31, 2006 from $59.56 per bbl for the three months ended March 31, 2005, and increased 2% from $66.88 per bbl for the three months ended December 31, 2005. The increase in the realized crude oil price compared to the first quarter of 2005 was due mainly to higher world benchmark crude oil prices and a narrowing of the average Brent differential, offset by the strengthening Canadian dollar.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 5% from $62.34 per bbl for the three months ended March 31, 2005, to average $65.23 per bbl for the three months ended March 31, 2006, and increased 8% from $60.19 per bbl for the three months ended December 31, 2005. The increase in the realized crude oil price was due mainly to higher world benchmark crude oil prices, 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)	**Mar 31 2006**	Dec 31 2005
North America, related to pipeline fill	**1,097,526**	484,157
North Sea, related to timing of liftings	**1,528,040**	747,141
Offshore West Africa, related to timing of liftings	**584,931**	412,841
	3,210,497	1,644,139

DAILY PRODUCTION, before royalties

	Three Months Ended		
	Mar 31 2006	Dec 31 2005	Mar 31 2005
Crude oil and NGLs (bbl/d)			
North America	**222,955**	230,263	209,125
North Sea	**60,802**	66,798	71,139
Offshore West Africa	**39,905**	43,207	7,539
	323,662	340,268	287,803
Natural gas (mmcf/d)			
North America	**1,411**	1,402	1,430
North Sea	**17**	15	23
Offshore West Africa	**8**	6	2
	1,436	1,423	1,455
Total barrel of oil equivalent (boe/d)	**563,027**	577,505	530,316
Product mix			
Light / medium crude oil and NGLs	**27%**	28%	25%
Pelican Lake crude oil	**5%**	5%	3%
Primary heavy crude oil	**17%**	17%	17%
Thermal heavy crude oil	**8%**	9%	9%
Natural gas	**43%**	41%	46%

DAILY PRODUCTION, net of royalties

	Three Months Ended		
	Mar 31 2006	Dec 31 2005	Mar 31 2005
Crude oil and NGLs (bbl/d)			
North America	**192,747**	198,047	179,472
North Sea	**60,694**	66,664	71,074
Offshore West Africa	**38,958**	42,081	7,310
	292,399	306,792	257,856
Natural gas (mmcf/d)			
North America	**1,120**	1,124	1,148
North Sea	**17**	15	23
Offshore West Africa	**8**	6	2
	1,145	1,145	1,173
Total barrel of oil equivalent (boe/d)	**483,143**	497,679	453,385

Daily production and per barrel statistics are presented throughout the MD&A on a "before royalty" basis. Production, net of royalties, 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 563,027 boe/d for the three months ended March 31, 2006, a 6% increase from the three months ended March 31, 2005. The increase in production was due to 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, partially offset by decreased production in the North Sea.

Total crude oil and NGLs production for the three months ended March 31, 2006 increased 12% to 323,662 bbl/d from 287,803 bbl/d for the three months ended March 31, 2005. Crude oil and NGLs production in the first quarter of 2006 was in line with the Company's previously issued guidance of 306,000 to 334,000 bbl/d.

Natural gas production continues to represent the Company's largest product offering. Natural gas production for the three months ended March 31, 2006 decreased slightly to average 1,436 mmcf/d compared to 1,455 mmcf/d for the three months ended March 31, 2005. The Company's first quarter natural gas production was within the Company's previously issued guidance of 1,426 to 1,475 mmcf/d.

As a result of the Company's decision to reduce overall North America drilling activity for the remainder of 2006, and to shift capital from its natural gas program to its crude oil program, the Company has revised its 2006 production guidance. The Company currently expects annual production levels in 2006 to average 1,448 to 1,516 mmcf/d of natural gas and 338,000 to 370,000 bbl/d of crude oil and NGLs. Second quarter 2006 production guidance is 1,461 to 1,520 mmcf/d of natural gas and 326,000 to 348,000 bbl/d of crude oil and NGLs.

North America

North America crude oil and NGLs production for the three months ended March 31, 2006 increased 7% to average 222,955 bbl/d, up from 209,125 bbl/d for the three months ended March 31, 2005. 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. First quarter crude oil and NGLs production decreased 3% from 230,263 bbl/d for the three months ended December 31, 2005 due to the timing of the Primrose production cycle.

North America natural gas production for the three months ended March 31, 2006 decreased slightly to average 1,411 mmcf/d from 1,430 mmcf/d for the three months ended March 31, 2005. The winter drilling program was negatively impacted by warmer than normal weather, which precluded timely access to many locations in Northern Alberta and Northeast British Columbia. This situation improved markedly in late February allowing much of the planned locations to be drilled. As a result, however, approximately 70 mmcf/d of natural gas production was delayed. The Company anticipates that some locations will be tied-in during the second and third quarters of 2006; however the Company anticipates that 20 - 30 mmcf/d will not be tied-in until freeze up late in the fourth quarter of 2006 or early in the first quarter of 2007.

North Sea

North Sea crude oil production for the three months ended March 31, 2006 averaged 60,802 bbl/d, 15% lower than the 71,139 bbl/d in the three months ended March 31, 2005 and 9% lower than the 66,798 bbl/d in the prior quarter. Production levels were in line with expectations, reflecting anticipated temporary curtailments at the Lyell Field and the Columba E Terraces, as well as temporary restrictions at B-Block and Playfair.

Natural gas production in the North Sea for the three months ended March 31, 2006 averaged 17 mmcf/d compared to 23 mmcf/d for the three months ended March 31, 2005, and changed marginally from the prior quarter.

Offshore West Africa

Offshore West Africa crude oil production for the three months ended March 31, 2006 increased 429% to 39,905 bbl/d from 7,539 bbl/d for the three months ended March 31, 2005. The production increase was primarily due to commencement of production from the 57.61% owned and operated Baobab Field in August 2005. First quarter 2006 production decreased by 8% from 43,207 bbl/d in the prior quarter. This decrease was due in large part to limitations from monitoring sand screen effectiveness on one producing well.

ROYALTIES

	Three Months Ended		
	Mar 31 2006	Dec 31 2005	Mar 31 2005
Crude oil and NGLs ($/bbl)[1]			
North America	**$ 4.63**	$ 5.39	$ 4.58
North Sea	**$ 0.12**	$ 0.14	$ 0.05
Offshore West Africa	**$ 1.55**	$ 1.57	$ 1.90
Company average	**$ 3.48**	$ 3.89	$ 3.39
Natural gas ($/mcf)[1]			
North America	**$ 1.73**	$ 2.34	$ 1.33
North Sea	**$ -**	$ -	$ -
Offshore West Africa	**$ 0.13**	$ 0.14	$ 0.23
Company average	**$ 1.70**	$ 2.30	$ 1.30
Company average ($/boe)[1]	**$ 6.44**	$ 8.01	$ 5.42
Percentage of revenue[2]			
Crude oil and NGLs	**8%**	8%	9%
Natural gas	**21%**	20%	20%
Boe	**14%**	14%	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 three months ended March 31, 2006 increased from the three months ended March 31, 2005 primarily due to higher benchmark crude oil prices, offset by wider heavy oil differentials and a stronger Canadian dollar. First quarter 2006 crude oil and NGLs royalties per bbl decreased from the three months ended December 31, 2005 due to wider heavy oil differentials and a strengthening Canadian dollar, offset by higher benchmark crude oil prices. Based on current pricing, payout on the Primrose thermal projects is anticipated to be reached in the third or 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 for the three months ended March 31, 2006 increased from the three months ended March 31, 2005 due to higher benchmark natural gas prices.

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 and the Baobab Field are expected to reach payout in 2007, which will increase royalty rates and current income taxes in accordance with the PSCs.

PRODUCTION EXPENSE

	Three Months Ended		
	Mar 31 2006	Dec 31 2005	Mar 31 2005
Crude oil and NGLs ($/bbl)[1]			
North America	**$ 10.91**	$ 10.92	$ 10.07
North Sea	**$ 16.85**	$ 12.11	$ 14.91
Offshore West Africa	**$ 6.08**	$ 5.62	$ 11.43
Company average	**$ 11.33**	$ 10.33	$ 11.30
Natural gas ($/mcf)[1]			
North America	**$ 0.79**	$ 0.74	$ 0.66
North Sea	**$ 1.26**	$ 1.96	$ 2.52
Offshore West Africa	**$ 1.00**	$ 0.80	$ 1.25
Company average	**$ 0.80**	$ 0.76	$ 0.69
Company average ($/boe)[1]	**$ 8.46**	$ 7.93	$ 8.04

(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 three months ended March 31, 2006 increased 8% to $10.91 from $10.07 for the three months ended March 31, 2005. The increase from the first quarter of 2005 was primarily due to higher industry wide service costs. Based on expectations for the remainder of the year, the Company has reduced its annual North America crude oil and NGLs production expense guidance to $11.00 - $11.80 per bbl.

North America natural gas production expense per mcf for the three months ended March 31, 2006 increased over the three months ended March 31, 2005, and the prior quarter. This increase from the comparable periods is primarily due to the continued service and cost pressures seen industry wide. Natural gas production expense is expected to be lower over the remainder of the year due primarily to the impact of reduced seasonal costs through the spring and summer in natural gas areas. Based on the higher costs in the first quarter of 2006, and expectations for the remainder of the year the Company has revised its annual North America natural gas production expense guidance to $0.75 - $0.79 per mcf.

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 three months ended March 31, 2006 compared to the three months ended March 31, 2005 were primarily impacted by the commencement of production from the Baobab Field in August 2005.

MIDSTREAM

	Three Months Ended		
($ millions)	**Mar 31 2006**	Dec 31 2005	Mar 31 2005
Revenue	**$ 18**	$ 21	$ 21
Production expense	**5**	8	6
Midstream cash flow	**13**	13	15
Depreciation	**2**	2	2
Segment earnings before taxes	**$ 11**	$ 11	$ 13

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		
	Mar 31 2006	Dec 31 2005	Mar 31 2005
Expense ($ millions)	**$ 519**	$ 548	$ 472
$/boe[2]	**$ 10.56**	$ 10.44	$ 9.89

(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 three months ended March 31, 2006 increased in total and on a boe basis from the three months ended March 31, 2005. The increase in DD&A on a boe basis was primarily due to 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. DD&A decreased in total from the prior quarter as a result of lower sales volumes due to the timing of liftings and production volumes used as pipeline line fill.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three Months Ended		
	Mar 31 2006	Dec 31 2005	Mar 31 2005
Expense ($ millions)	**$ 17**	$ 16	$ 18
$/boe[1]	**$ 0.34**	$ 0.30	$ 0.38

(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		
	Mar 31 2006	Dec 31 2005	Mar 31 2005
Net expense ($ millions)	**$ 42**	$ 36	$ 35
$/boe[1]	**$ 0.85**	$ 0.68	$ 0.74

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

Administration expense for the three months ended March 31, 2006 increased in total and on a boe basis from the three months ended March 31, 2005 and the three months ended December 31, 2005. The increase from the first quarter of 2005 was primarily due to increased insurance premiums related to hurricane activity in 2005 and increased staffing costs. The increase from the prior quarter was impacted by increased costs related to the Company's 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 three months ended March 31, 2006, the Company recognized $6 million of compensation expense under the Share Bonus Plan (December 31, 2005 - $3 million; March 31, 2005 - $7 million).

STOCK-BASED COMPENSATION

	Three Months Ended		
($ millions)	**Mar 31 2006**	Dec 31 2005	Mar 31 2005
Stock option plan	**$ 132**	$ 125	$ 184

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 $132 million ($88 million after tax) stock-based compensation expense for the three months ended March 31, 2006 in connection with the 13% appreciation in the Company's share price since December 31, 2005 (Company's share price as at: March 31, 2006 - C$64.90; December 31, 2005 - C$57.63; March 31, 2005 - C$34.18). 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 three months ended March 31, 2006 the Company capitalized $30 million in stock-based compensation on the Horizon Project (December 31, 2005 - $37 million; March 31, 2005 - $22 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 March 31, 2006. In periods when substantial stock price changes occur, the Company is subject to significant earnings volatility.

For the three months ended March 31, 2006, the Company paid $123 million for stock options surrendered for cash settlement (December 31, 2005 - $52 million; March 31, 2005 - $77 million).

INTEREST EXPENSE

	Three Months Ended		
	Mar 31 2006	Dec 31 2005	Mar 31 2005
Interest expense, gross ($ millions)	**$ 58**	**$** 55	**$** 54
Less: capitalized interest, Horizon Project	**$ 33**	**$** 27	**$** 11
Interest expense, net	**$ 25**	$ 28	$ 43
$/boe(1)	**$ 0.51**	$ 0.53	$ 0.91
Average effective interest rate	**5.7%**	5.7%	5.5%

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

Gross interest expense increased from the comparable quarters in 2005 primarily due to higher debt levels and carrying charges. Net interest expense decreased on a total and 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 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		
($ millions)	**Mar 31 2006**	Dec 31 2005	Mar 31 2005
Realized loss (gain)			
Crude oil and NGLs financial instruments	**$ 332**	$ 235	$ 105
Natural gas financial instruments	**56**	242	(10)
Interest rate swaps	**-**	(1)	(8)
	$ 388	$ 476	$ 87
Unrealized loss (gain)			
Crude oil and NGLs financial instruments	**$ 114**	$ (514)	$ 907
Natural gas financial instruments	**(104)**	(307)	86
Interest rate swaps	**(2)**	(4)	5
	$ 8	$ (825)	$ 998
Total	**$ 396**	$ (349)	$ 1,085

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

	Three Months Ended		
	Mar 31 2006	Dec 31 2005	Mar 31 2005
Crude oil and NGLs ($/bbl)(1)	**$ 12.04**	$ 7.67	$ 4.07
Natural gas ($/mcf)(1)	**$ 0.43**	$ 1.85	$ (0.08)

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

The effect of the realized gain on non-designated interest rate swaps decreased the Company's interest expense as follows:

($ millions)	Three Months Ended **Mar 31 2006**	Dec 31 2005	Mar 31 2005
Interest expense as reported	**$ 25**	$ 28	$ 43
Realized risk management gain	**-**	(1)	(8)
	$ 25	$ 27	$ 35
Average effective interest rate	**5.7%**	5.6%	4.5%

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 March 31, 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 March 31, 2006. Due to changes in the crude oil and natural gas forward pricing at March 31, 2006, the Company recorded a net $8 million ($5 million after tax) unrealized loss on its risk management activities for the three months ended March 31, 2006 (December 31, 2005 - unrealized gain of $825 million; March 31, 2005 - unrealized loss of $998 million).

In addition to the risk management liability recognized on the balance sheet at March 31, 2006, the net unrecognized liability related to the fair value of derivative financial instruments designated as hedges was $521 million at March 31, 2006 (December 31, 2005 - $990 million).

Details related to outstanding derivative financial instruments at March 31, 2006 are disclosed in note 7 to the Company's unaudited interim consolidated financial statements

FOREIGN EXCHANGE

($ millions)	Three Months Ended **Mar 31 2006**	Dec 31 2005	Mar 31 2005
Realized foreign exchange gain	**$ (5)**	$ (16)	$ (12)
Unrealized foreign exchange loss	**10**	5	-
	$ 5	$ (11)	$ (12)

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 gain was the result of the effects of foreign exchange rate fluctuations on working capital items denominated in US dollars or UK pounds sterling. Unrealized foreign exchange loss is related to the fluctuation of the Canadian dollar in relation to the US dollar with respect to the US dollar debt, and working capital denominated in US dollars or UK pounds sterling. The Canadian dollar ended the first quarter at US$0.8568 compared to US$0.8267 at March 31, 2005 (December 31, 2005 - US$0.8577).

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

	Three Months Ended		
($ millions, except income tax rates)	**Mar 31 2006**	Dec 31 2005	Mar 31 2005
Taxes other than income tax			
Current	**$ 35**	$ 50	$ 42
Deferred	**26**	1	-
	$ 61	$ 51	$ 42
Current income tax			
North America – Current income tax	**$ 15**	$ 2	$ 30
North America – Large corporations tax	**3**	5	2
North Sea	**1**	31	39
Offshore West Africa	**13**	19	3
Other	**-**	1	-
	$ 32	$ 58	$ 74
Future income tax expense	**$ 268**	$ 514	$ (241)
Effective income tax rate	**83.9%(1)**	34.1%	28.3%

(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, effective January 1, 2006.

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.

The North Sea current income tax expense for the three months ended March 31, 2006 decreased from the three months ended March 31, 2005 and the prior quarter primarily due to the effect of decreased crude oil production, the timing of liftings from various fields and the level of capital expenditures, offset by increased realized crude oil prices. Effective January 1, 2006, the UK government substantively enacted an increase to the supplementary charge on profits from UK North Sea crude oil and natural gas production from 10% to 20%, increasing the Company's effective income tax rate in the North Sea to approximately 50%. The supplementary charge excludes any deduction for financing costs. The Company's future income tax liability was increased by $110 million as at January 1, 2006, with respect to this tax rate change.

Subsequent to March 31, 2006, the provinces of Alberta and Saskatchewan substantively enacted reductions in their corporate income tax rates that will result in a reduction of future tax liabilities of approximately $160 million. This reduction will be reflected in the Company's reported results of operations in the second quarter of 2006.

CAPITAL EXPENDITURES [(1)]

($ millions)	Three Months Ended Mar 31 2006	Dec 31 2005	Mar 31 2005
Expenditures on property, plant and equipment			
Net property acquisitions	**$ 12**	$ 19	$ 2
Land acquisition and retention	**99**	97	36
Seismic evaluations	**52**	40	41
Well drilling, completion and equipping	**936**	629	634
Pipeline and production facilities	**500**	314	432
Total net reserve replacement expenditures	**1,599**	1,099	1,145
Horizon Project:			
Phase 1 construction costs[(2)]	**616**	469	131
Phases 2 and 3 costs	**1**	-	-
Capitalized interest, stock-based compensation and other[(2)]	**69**	88	84
Total Horizon Project	**686**	557	215
Midstream	**3**	1	4
Abandonments[(3)]	**15**	16	4
Head office	**6**	6	4
Total net capital expenditures	**$ 2,309**	$ 1,679	$ 1,372
By segment			
North America	**$ 1,404**	$ 862	$ 940
North Sea	**138**	118	57
Offshore West Africa	**50**	119	144
Other	**7**	-	4
Horizon Project	**686**	557	215
Midstream	**3**	1	4
Abandonments[(3)]	**15**	16	4
Head office	**6**	6	4
Total	**$ 2,309**	$ 1,679	$ 1,372

(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 between 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 three months ended March 31, 2006 were $2,309 million compared to $1,372 million in the three months ended March 31, 2005 and $1,679 million in the three months ended December 31, 2005. The increase was primarily related to increased capital expenditures on the Horizon Project and increased activity on the North America conventional drilling program. In the first quarter, the Company drilled a total of 890 net wells consisting of 440 natural gas wells, 92 crude oil wells, 297 stratigraphic test and service wells, and 61 wells that were dry. The 297 stratigraphic test and service wells include 103 stratigraphic test wells related to the Horizon Project. This compared to 691 net wells drilled in the first quarter of 2005. The Company achieved an overall success rate of 90%, excluding stratigraphic test and service wells.

North America

North America accounted for approximately 91% of the total capital expenditures for the three months ended March 31, 2006 compared to approximately 85% in the comparable period in 2005.

During the first quarter 2006, the Company targeted to drill 499 net natural gas wells, including 191 wells in Northeast British Columbia, 186 wells in the Northern Plains region, 80 wells in Northwest Alberta, and 42 wells in the Southern Plains region. The Company also targeted 90 net crude oil wells during the first quarter 2006. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 33 heavy crude oil wells, 22 Pelican Lake crude oil wells, 20 thermal crude oil wells, and 4 light crude oil wells were drilled. Another 11 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. This situation improved markedly in late February, allowing many of the planned locations to be drilled.

Due to cost pressures and 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 oil differentials starting in the second quarter of 2006. As a result, the Company decided to maintain its planned capital expenditure level which will result in a slight reduction in drilling activity. The Company will drill 150 fewer natural gas wells, a 13% reduction from the original plan for 2006.

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 174 stratigraphic test wells, and has drilled 20 thermal oil wells that are currently producing. First steaming for the Primrose North expansion project commenced in November 2005 and current production is approximately 15,000 bbl/d. Overall Primrose thermal production for the three months ended March 31, 2006 was approximately 47,000 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 kilometres from its existing Primrose South steam plant and 25 kilometres 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 January 2009.

Development of new acreage and secondary recovery conversion projects at Pelican Lake continued as expected through the first quarter of 2006. Drilling consisted of 22 horizontal producing wells, 13 stratigraphic wells and 4 water source wells, with plans to drill 117 additional horizontal wells over the remainder of the year. The North Brintnell waterflood conversion project was expanded by 744 acres. The pressure response from the Polymer Flood pilot continued to be positive. The Company commenced installation of the first two polymer skids as part of the commercial Polymer Flood project. Pelican Lake production was approximately 29,000 bbl/d for the first quarter.

In the second quarter of 2006, the Company's overall drilling activity in North America is expected to be comprised of 66 natural gas wells and 87 crude oil wells excluding stratigraphic and service wells.

Horizon Oil Sands Project

The Horizon Project continued on schedule and on budget with construction 26% complete at quarter end. The project status as at March 31, 2006 was as follows:

- Completed 60% model reviews in all areas;
- Awarded total contracts and purchase orders in excess of $4 billion;
- Four coke drums were delivered to the site as planned and installed on schedule;
- Completed transport of the naptha reactor to the site from the rail staging area south of Fort McMurray;
- Started setting of piperack modules on foundations; and
- Site preparation and underground infrastructure 98% complete.

Major activities for the second quarter of 2006 will include:

- Overall detailed engineering anticipated to surpass 80%;
- Occupancy of the second of three camps; and
- Ore preparation plant site turnover by mining to bitumen production.

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 first quarter, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During the first quarter, 2.8 net wells were drilled, with an additional 3.7 net wells drilling at quarter-end.

Construction of the sub-sea water injection pump at the Columba E Terrace progressed during the first quarter. This will be tied into 2 additional sub-sea water injection wells that will be drilled late in 2006.

Further development of the Lyell Field progressed on schedule. This project comprises the drilling of 4 net wells and workovers at 2 existing wells during 2006 and 2007. At its peak, the Company's share of net production is forecasted to be approximately 20,000 boe/d.

Offshore West Africa

Offshore West Africa capital expenditures included the drilling and tie in of 2 additional wells at Baobab. Both wells were tied into the Baobab floating production, storage and offtake vessel ("FPSO") during the first quarter of 2006.

At East Espoir, the 2 remaining planned wells were successfully delivered in the first quarter of 2006. The drilling of these wells was a result of additional testing and evaluation that revealed a larger quantity of crude oil in place, based upon reservoir studies and production history to date. These new producer wells will effectively exploit this additional potential and could increase the recoverable resources and production. The West Espoir drilling tower, which will facilitate development drilling of the reservoir, is on site and was installed in late 2005. This project is progressing on time and on budget with first crude oil expected in 2006, increasing the Company's share of net production to approximately 13,000 boe/d once fully developed.

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. Following engineering design and request for tenders, development is expected to begin in late 2006, with first oil expected late in 2008 and a peak production rate of approximately 20,000 bbl/d.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Mar 31 2006**	Dec 31 2005	Mar 31 2005
Working capital deficit[1]	**$ 2,065**	$ 1,774	$ 1,288
Long-term debt	**$ 4,342**	$ 3,321	$ 3,831
Shareholders' equity			
Share capital	**$ 2,500**	$ 2,442	$ 2,416
Retained earnings	**5,821**	5,804	4,468
Foreign currency translation adjustment	**(11)**	(9)	(6)
Total	**$ 8,310**	$ 8,237	$ 6,878
Debt to cash flow[2]	**0.9x**	0.7x	1.0x
Debt to EBITDA[3]	**0.8x**	0.6x	0.9x
Debt to book capitalization[4]	**34.3%**	28.7%	36.9%
Debt to market capitalization	**11.1%**	9.7%	18.0%
After tax return on average common shareholders' equity[5]	**20.3%**	14.3%	10.7%
After tax return on average capital employed[6]	**14.2%**	10.4%	8.1%

(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 March 31, 2006 consist primarily of cash flow from operations, access to capital markets and available credit facilities. 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 March 31, 2006 the Company had undrawn bank lines of credit of $2,687 million. These credit lines are supported by credit facilities, which if not extended, mature in 2008, 2009 and 2010.

At March 31, 2006, the working capital deficit was $2,065 million and included the current portion of other long-term liabilities of $1,397 million, comprised of stock-based compensation of $629 million and the mark-to-market valuation of non-designated risk management financial derivative instruments of $768 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 March 31, 2006.

The Company is committed to maintaining a strong financial position. In the first quarter of 2006, strong operational results and high commodity prices resulted in a debt to book capitalization level of 34.3%. 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 March 31, 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 55% of budgeted natural gas volumes have been hedged through the use of collars for the remainder of 2006.

Long-term debt

Long-term debt as at March 31, 2006 was $4,342 million. The debt to EBITDA ratio was 0.8x (December 31, 2005 - 0.6x; March 31, 2005 - 0.9x) and the debt to book capitalization was 34.3% (December 31, 2005 - 28.7%; March 31, 2005 - 36.9%) as at March 31, 2006. These ratios are currently 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 March 31, 2006 the Company had in place unsecured syndicated bank credit facilities of $3,455 million, comprised of:

– a $100 million operating demand credit facility;
– a two-tranche 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 for the Company's North Sea operations.

The first $1,000 million tranche of the $1,825 million facility is fully revolving for a period of three years maturing June 2008. The second tranche of $825 million is fully revolving for a period of five years maturing June 2010. Both tranches are extendible annually for one year periods at the mutual agreement of the Company and the lenders. If the facility is not extended, the full amount of the outstanding principal would be repayable on the respective maturity dates. The $1,500 million credit and term loan facility is fully revolving for a period of five years maturing December 2009. The facility has three, one year extension provisions at the mutual agreement of the Company and the lenders. If the facility is 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 performance guarantees aggregating $65 million were also outstanding at March 31, 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. If issued, these securities will bear interest as determined at the date of issuance.

Share capital

As at March 31, 2006, there were 537,272,000 common shares outstanding. As at May 3, 2006, the Company had 537,390,000 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 up to 26,852,545 common shares or 5% of the outstanding common shares of the Company on the date of the announcement, during the 12-month period beginning January 24, 2006 and ending January 23, 2007. As at May 3, 2006, the Company had not purchased any shares under its Normal Course Issuer Bid.

In February 2006, the Company's Board of Directors approved an increase in the annual dividend paid by the Company from $0.236 in 2005 to $0.30 per common share for 2006.

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 March 31, 2006:

($ millions)	2006	2007	2008	2009	2010	Thereafter
Product transportation and pipeline(1)	$ 156	$ 169	$ 174	$ 121	$ 112	$ 1,121
Offshore equipment operating lease	$ 39	$ 51	$ 52	$ 51	$ 51	$ 180
Offshore drilling	$ 104	$ 132	$ 40	$ -	$ -	$ -
Asset retirement obligations(2)	$ 67	$ 4	$ 4	$ 4	$ 7	$ 3,274
Long-term debt(3)	$ -	$ 161	$ 36	$ 36	$ -	$ 3,368
Other(4)	$ 47	$ 65	$ 26	$ 33	$ 27	$ 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.

The Board of Directors has 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 $1.9 billion to March 31, 2006, $2.0 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 first 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	$ 102	$ 0.19	$ 71	$ 0.13
Including financial derivatives	$ 68	$ 0.13	$ 46	$ 0.09
Natural gas – AECO C$0.10/mcf[(2)]				
Excluding financial derivatives	$ 38	$ 0.07	$ 25	$ 0.05
Including financial derivatives	$ 26	$ 0.05	$ 17	$ 0.03
Volume changes				
Crude oil – 10,000 bbl/d	$ 89	$ 0.17	$ 42	$ 0.08
Natural gas – 10 mmcf/d	$ 21	$ 0.04	$ 10	$ 0.02
Foreign currency rate change				
$0.01 change in C$ in relation to US$[(2)]	$ 61	$ 0.11	$ 19	$ 0.03
Interest rate change - 1%	$ 10	$ 0.02	$ 10	$ 0.02

(1) The sensitivities are calculated based on 2006 first 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

($/boe)[1]	Three Months Ended **Mar 31 2006**	Dec 31 2005	Mar 31 2005
Sales price[2]	**$ 46.30**	$ 56.08	$ 39.94
Royalties	**6.44**	8.01	5.42
Production expense[3]	**8.46**	7.93	8.04
Netback	**31.40**	40.14	26.48
Midstream contribution[3]	**(0.25)**	(0.25)	(0.31)
Administration	**0.85**	0.68	0.74
Interest, net	**0.51**	0.53	0.91
Realized risk management loss	**7.90**	9.07	1.83
Realized foreign exchange gain	**(0.12)**	(0.29)	(0.25)
Taxes other than income tax - current	**0.71**	0.93	0.87
Current income tax - North America	**0.29**	0.04	0.63
Current income tax - Large corporations tax	**0.07**	0.11	0.05
Current income tax - North Sea	**0.01**	0.59	0.81
Current income tax - Offshore West Africa	**0.27**	0.35	0.06
Current income tax - other	**-**	0.02	-
Cash flow	**$ 21.16**	$ 28.36	$ 21.14

(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)	**Mar 31 2006**	Dec 31 2005
ASSETS		
Current assets		
Cash and cash equivalents	**$ 12**	$ 18
Accounts receivable and other	**1,345**	1,546
Future income tax	**495**	487
	1,852	2,051
Property, plant and equipment	**21,465**	19,694
Other long-term assets	**122**	107
	$ 23,439	$ 21,852
LIABILITIES		
Current liabilities		
Accounts payable	**$ 621**	$ 573
Accrued liabilities	**1,899**	1,781
Current portion of other long-term liabilities (note 3)	**1,397**	1,471
	3,917	3,825
Long-term debt (note 2)	**4,342**	3,321
Other long-term liabilities (note 3)	**1,526**	1,434
Future income tax	**5,344**	5,035
	15,129	13,615
SHAREHOLDERS' EQUITY		
Share capital (note 5)	**2,500**	2,442
Retained earnings	**5,821**	5,804
Foreign currency translation adjustment	**(11)**	(9)
	8,310	8,237
	$ 23,439	$ 21,852

Commitments (note 8)

Consolidated statements of earnings (loss)

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended Mar 31 2006	Mar 31 2005
Revenue	**$ 2,372**	$ 1,993
Less: royalties	**(316)**	(259)
Revenue, net of royalties	**2,056**	1,734
Expenses		
Production	**419**	389
Transportation	**81**	67
Depletion, depreciation and amortization	**521**	474
Asset retirement obligation accretion (note 3)	**17**	18
Administration	**42**	35
Stock-based compensation (note 3)	**132**	184
Interest, net	**25**	43
Risk management activities (note 7)	**396**	1,085
Foreign exchange loss (gain)	**5**	(12)
	1,638	2,283
Earnings (loss) before taxes	**418**	(549)
Taxes other than income tax	**61**	42
Current income tax expense (note 4)	**32**	74
Future income tax expense (recovery) (note 4)	**268**	(241)
Net earnings (loss)	**$ 57**	$ (424)
Net earnings (loss) per common share (note 6)		
Basic and diluted	**$ 0.11**	$ (0.79)

Consolidated statements of retained earnings

(millions of Canadian dollars, unaudited)	Three Months Ended Mar 31 2006	Mar 31 2005
Balance – beginning of period	**$ 5,804**	$ 4,922
Net earnings (loss)	**57**	(424)
Dividends on common shares (note 5)	**(40)**	(30)
Balance – end of period	**$ 5,821**	$ 4,468

Consolidated statements of cash flows

(millions of Canadian dollars, unaudited)	Three Months Ended Mar 31 2006	Mar 31 2005
Operating activities		
Net earnings (loss)	**$ 57**	$ (424)
Non-cash items		
Depletion, depreciation and amortization	**521**	474
Asset retirement obligation accretion	**17**	18
Stock-based compensation	**132**	184
Unrealized risk management activities	**8**	998
Unrealized foreign exchange loss	**10**	-
Deferred petroleum revenue tax	**26**	-
Future income tax expense (recovery)	**268**	(241)
Deferred charges	**(15)**	(5)
Abandonment expenditures	**(15)**	(4)
Net change in non-cash working capital	**(311)**	(222)
	698	778
Financing activities		
Issue of bankers' acceptances	**619**	273
Issue of medium-term notes	**400**	-
Issue of common shares on exercise of stock options	**10**	2
Dividends on common shares	**(32)**	(27)
Net change in non-cash working capital	**2**	16
	999	264
Investing activities		
Expenditures on property, plant and equipment	**(2,294)**	(1,368)
Net change in non-cash working capital	**591**	339
	(1,703)	(1,029)
(Decrease) increase in cash	**(6)**	13
Cash – beginning of period	**18**	28
Cash – end of period	**$ 12**	$ 41
Interest paid	**$ 52**	$ 44
Taxes paid		
Taxes other than income tax	**$ 81**	$ 110
Current income tax	**$ 173**	$ 111

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

	Mar 31 2006	Dec 31 2005
Bank credit facilities		
Bankers' acceptances	**$ 741**	$ 122
Medium-term notes	**925**	525
Senior unsecured notes (2006 and 2005 – US$93 million)	**108**	108
US dollar debt securities (2006 and 2005 – US$2,200 million)	**2,568**	2,566
	$ 4,342	$ 3,321

Bank credit facilities

As at March 31, 2006, the Company had in place unsecured syndicated bank credit facilities of $3,455 million, comprised of:

- a $100 million operating demand credit facility;
- a two-tranche 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.

The first $1,000 million tranche of the $1,825 million facility is fully revolving for a period of three years maturing June 2008. The second tranche of $825 million is fully revolving for a period of five years maturing June 2010. Both tranches are extendible annually for one year periods at the mutual agreement of the Company and the lenders. If the facility is not extended, the full amount of the outstanding principal would be repayable on the respective maturity dates. The $1,500 million credit and term loan facility is fully revolving for a period of five years maturing December 2009. The facility has three, one-year extension provisions at the mutual agreement of the Company and the lenders. If the facility is 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 March 31, 2006, was 4.4% (December 31, 2005 – 4.0%).

In addition to the outstanding debt, letters of credit and performance guarantees aggregating $65 million were outstanding at March 31, 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. If issued, these securities will bear interest as determined at the date of issuance.

3. OTHER LONG–TERM LIABILITIES

	Mar 31 2006	Dec 31 2005
Asset retirement obligations	**$ 1,118**	$ 1,112
Stock-based compensation	**882**	891
Risk management (note 7)	**893**	885
Other	**30**	17
	2,923	2,905
Less: current portion	**1,397**	1,471
	$ 1,526	$ 1,434

Asset retirement obligations

At March 31, 2006, the Company's total estimated undiscounted cost to settle its asset retirement obligations was approximately $3,360 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:

	Three Months Ended Mar 31, 2006	Year Ended Dec 31, 2005
Balance – beginning of period	**$ 1,112**	$ 1,119
Liabilities incurred	**5**	47
Liabilities settled	**(15)**	(46)
Asset retirement obligation accretion	**17**	69
Revision of estimates	**-**	(56)
Foreign exchange	**(1)**	(21)
Balance – end of period	**$ 1,118**	$ 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.

	Three Months Ended Mar 31, 2006	Year Ended Dec 31, 2005
Balance – beginning of period	**$ 891**	$ 323
Stock-based compensation provision	**132**	723
Current period payment for options surrendered	**(123)**	(227)
Transferred to common shares	**(48)**	(29)
Capitalized to Horizon Project	**30**	101
Balance – end of period	**882**	891
Less: current portion of stock-based compensation	**629**	629
	$ 253	$ 262

4. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended	
	Mar 31 2006	Mar 31 2005
Current income tax – North America	**$ 15**	$ 30
Large corporations tax – North America	**3**	2
Current income tax – North Sea	**1**	39
Current income tax – Offshore West Africa	**13**	3
Current income tax expense	**32**	74
Future income tax expense (recovery)	**268**	(241)
Income tax expense (recovery)	**$ 300**	$ (167)

A significant portion of the Company's North American taxable income is generated by partnerships. 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.

Effective January 1, 2006, the UK government substantively enacted an increase to the supplementary charge on profits from UK North Sea crude oil and natural gas production from 10% to 20%, increasing the Company's effective income tax rate in the North Sea to approximately 50%. The supplementary charge excludes any deduction for financing costs. The Company's future income tax liability was increased by $110 million as at January 1, 2006, with respect to this tax rate change.

Subsequent to March 31, 2006, the provinces of Alberta and Saskatchewan substantively enacted reductions in their corporate income tax rates that will result in a reduction of future tax liabilities of approximately $160 million. This reduction will be reflected in the Company's reported results of operations in the second quarter of 2006.

5. SHARE CAPITAL

Issued Common shares	Three Months Ended Mar 31, 2006 Number of shares (thousands)	Amount
Balance – beginning of period	**536,348**	**$ 2,442**
Issued upon exercise of stock options	**924**	**10**
Previously recognized liability on stock options exercised for common shares	**-**	**48**
Balance – end of period	**537,272**	**$ 2,500**

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 up to 26,852,545 common shares or 5% of the outstanding common shares of the Company on the date of the announcement, during the 12-month period beginning January 24, 2006 and ending January 23, 2007. As at March 31, 2006, the Company had not purchased any shares under the Normal Course Issuer Bid.

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 pays regular quarterly dividends in January, April, July, and October of each year.

Stock Options

	Three Months Ended Mar 31, 2006 Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of period	**30,510**	**$ 17.79**
Granted	**4,407**	**$ 60.33**
Exercised for common shares	**(924)**	**$ 9.19**
Surrendered for cash settlement	**(2,661)**	**$ 12.07**
Forfeited	**(375)**	**$ 30.09**
Outstanding – end of period	**30,957**	**$ 24.44**
Exercisable – end of period	**10,075**	**$ 13.27**

6. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended	
	Mar 31 2006	Mar 31 2005[1]
Weighted average common shares outstanding (thousands) – basic and diluted	**537,227**	536,330
Net earnings (loss) – basic and diluted	**$ 57**	$ (424)
Net earnings (loss) per common share - basic and diluted	**$ 0.11**	$ (0.79)

(1) Restated to reflect two-for-one common share split in May 2005.

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:

	Three Months Ended Mar 31, 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	**334**	**-**	190	-
Net change in fair value of outstanding derivative financial instruments	**(11)**	**-**	(943)	-
Amortization of deferred revenue	**-**	**3**	-	18
	(554)	**(5)**	(687)	(8)
Add: Put premium financing obligations	**(334)**	**-**	(190)	-
Balance – end of period	**(888)**	**(5)**	(877)	(8)
Less: current portion	**763**	**5**	834	8
	$ (125)	**$ -**	$ (43)	$ -

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 from risk management activities for the periods ended March 31 were as follows:

	Three Months Ended	
	Mar 31 2006	Mar 31 2005
Net realized risk management loss	**$ 388**	$ 87
Net unrealized risk management mark-to-market loss	**8**	998
	$ 396	$ 1,085

As at March 31, 2006, the net unrecognized liability related to the estimated fair values of derivative financial instruments designated as hedges was $521 million (December 31, 2005 - $990 million).

The Company had the following financial derivatives outstanding as at March 31, 2006:

	Remaining term	Volume	Average price	Index
Crude oil				
Crude oil price collars	Apr 2006 – Dec 2006	160,000 bbl/d	US$38.17 – US$48.16	WTI
	Apr 2006 – Dec 2006	90,000 bbl/d	US$45.00 – US$77.93	WTI
	Apr 2006 – Dec 2006	22,000 bbl/d	C$46.53 – C$58.67	WTI
Crude oil puts	Apr 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$28.00	WTI
	Jan 2007 – Dec 2007	100,000 bbl/d	US$45.00	WTI
	Jan 2007 – Dec 2007	100,000 bbl/d	US$50.00	WTI
Brent differential swaps	Apr 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

	Remaining term	Volume	Average price	Index
Natural gas				
AECO collars	Apr 2006 – Jun 2006	973,000 GJ/d	C$5.71 – C$8.15	AECO
	Apr 2006 – Jun 2006	100,000 GJ/d	C$7.00 – C$14.16	AECO
	Jul 2006 – Sep 2006	705,000 GJ/d	C$5.61 – C$7.61	AECO
	Jul 2006 – Sep 2006	100,000 GJ/d	C$7.00 – C$14.16	AECO
	Oct 2006 – Dec 2006	237,500 GJ/d	C$5.61 – C$7.61	AECO
	Oct 2006 – Dec 2006	100,000 GJ/d	C$7.00 – C$14.16	AECO
	Nov 2006 – Dec 2006	700,000 GJ/d	C$7.50 – C$18.80	AECO
	Jan 2007 - Mar 2007	700,000 GJ/d	C$7.50 – C$18.80	AECO

	Remaining term			Amount ($ millions)	Fixed rate	Floating rate
Interest rate						
Swaps – fixed to floating	Apr 2006	–	Oct 2012	US$350	5.45%	LIBOR[1] + 0.81%
	Apr 2006	–	Dec 2014	US$350	4.90%	LIBOR[1] + 0.38%
Swaps – floating to fixed	Apr 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]	$	156	$	169	$	174	$	121	$	112	$	1,121
Offshore equipment operating lease	$	39	$	51	$	52	$	51	$	51	$	180
Offshore drilling	$	104	$	132	$	40	$	-	$	-	$	-
Asset retirement obligations[2]	$	67	$	4	$	4	$	4	$	7	$	3,274
Other[3]	$	47	$	65	$	26	$	33	$	27	$	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.

The Board of Directors has approved the construction costs for Phase 1 of the Horizon Oil Sands Project ("Horizon Project"), which are budgeted to be $6.8 billion, including a contingency fund of $700 million, with cumulative spending of $1.9 billion to March 31, 2006, $2.0 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 Three Months Ended Mar 31		North Sea Three Months Ended Mar 31		Offshore West Africa Three Months Ended Mar 31		Midstream Three Months Ended Mar 31	
	2006	2005	**2006**	2005	**2006**	2005	**2006**	2005
Segmented revenue	**1,820**	1,544	**320**	394	**227**	44	**18**	21
Less: royalties	**(310)**	(257)	**(1)**	(1)	**(5)**	(1)	**-**	-
Segmented revenue, net of royalties	**1,510**	1,287	**319**	393	**222**	43	**18**	21
Segmented expenses								
Production	**312**	275	**81**	101	**22**	8	**5**	6
Transportation	**88**	70	**3**	6	**-**	-	**-**	-
Depletion, depreciation and amortization	**415**	384	**60**	82	**44**	6	**2**	2
Asset retirement obligation accretion	**8**	9	**8**	9	**1**	-	**-**	-
Realized risk management activities	**317**	59	**71**	28	**-**	-	**-**	-
Total segmented expenses	**1,140**	797	**223**	226	**67**	14	**7**	8
Segmented earnings (loss) before the following	**370**	490	**96**	167	**155**	29	**11**	13
Non-segmented expenses								
Administration								
Stock-based compensation								
Interest, net								
Unrealized risk management activities								
Foreign exchange loss (gain)								
Total non-segmented expenses								
Earnings (loss) before taxes								
Taxes other than income tax								
Current income tax expense								
Future income tax expense (recovery)								
Net earnings (loss)								

(millions of Canadian dollars, unaudited)	Inter-segment elimination and other Three Months Ended Mar 31		Total Three Months Ended Mar 31	
	2006	2005	**2006**	2005
Segmented revenue	**(13)**	(10)	**2,372**	1,993
Less: royalties	**-**	-	**(316)**	(259)
Segmented revenue, net of royalties	**(13)**	(10)	**2,056**	1,734
Segmented expenses				
Production	**(1)**	(1)	**419**	389
Transportation	**(10)**	(9)	**81**	67
Depletion, depreciation and amortization	**-**	-	**521**	474
Asset retirement obligation accretion	**-**	-	**17**	18
Realized risk management activities	**-**	-	**388**	87
Total segmented expenses	**(11)**	(10)	**1,426**	1,035
Segmented earnings (loss) before the following	**(2)**	-	**630**	699
Non-segmented expenses				
Administration			**42**	35
Stock-based compensation			**132**	184
Interest, net			**25**	43
Unrealized risk management activities			**8**	998
Foreign exchange loss (gain)			**5**	(12)
Total non-segmented expenses			**212**	1,248
Earnings (loss) before taxes			**418**	(549)
Taxes other than income tax			**61**	42
Current income tax expense			**32**	74
Future income tax expense (recovery)			**268**	(241)
Net earnings (loss)			**57**	(424)

Net additions to property, plant and equipment

	Three Months Ended					
	Mar 31, 2006			Mar 31, 2005		
	Cash Expenditures	**Non-Cash/ Fair Value Changes(1)**	**Capitalized Costs**	Cash Expenditures	Non-Cash/ Fair Value Changes(1)	Capitalized Costs
North America	**$ 1,404**	**$ 5**	**$ 1,409**	$ 940	$ 9	$ 949
North Sea	**138**	**-**	**138**	57	-	57
Offshore West Africa	**50**	**-**	**50**	144	-	144
Other	**7**	**-**	**7**	4	-	4
Horizon Project(2)	**686**	**-**	**686**	215	-	215
Midstream	**3**	**-**	**3**	4	-	4
Head office	**6**	**-**	**6**	4	-	4
	$ 2,294	**$ 5**	**$ 2,299**	$ 1,368	$ 9	$ 1,377

(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.

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 ceases once construction is substantially complete. For the three months ended March 31, 2006, pre-tax interest of $33 million was capitalized to the Horizon Project (March 31, 2005 - $11 million).

	Property, plant and equipment		Total assets	
	Mar 31 2006	Dec 31 2005	**Mar 31 2006**	Dec 31 2005
Segmented assets				
North America	**$ 15,301**	$ 14,310	**$ 16,721**	$ 15,939
North Sea	**1,761**	1,681	**2,004**	1,950
Offshore West Africa	**1,256**	1,253	**1,396**	1,371
Other	**20**	13	**31**	30
Horizon Project	**2,855**	2,169	**2,928**	2,239
Midstream	**204**	203	**291**	258
Head office	**68**	65	**68**	65
	$ 21,465	$ 19,694	**$ 23,439**	$ 21,852

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 March 31, 2006:	
Interest coverage (times)	
Net earnings(1)	12.3x
Cash flow from operations(2)	24.1x

(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.

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.

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Daylight Time, 11:00 a.m. Eastern Daylight Time on Thursday, May 4, 2006. The North American conference call number is 1-877-461-2814 and the outside North American conference call number is 001-416-695-6120. Please call in about 10 minutes before the starting time in order to be patched into the call. The conference call will also be broadcast live on the internet and may be accessed through the Canadian Natural website at www.cnrl.com.

A taped rebroadcast will be available until 6:00 p.m. Mountain Daylight Time on Thursday, May 11, 2006. To access the postview in North America, dial 1-888-509-0081. Those outside of North America, dial 001-416-695-5275. The passcode to use is 617639.

WEBCAST

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

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

2006 SECOND QUARTER RESULTS

2006 second quarter results are scheduled for release on Wednesday, August 2, 2006. A conference call will be held on that day at 9:00 a.m. Mountain Daylight Time, 11:00 a.m. Eastern Daylight Time.

ANNUAL GENERAL MEETING

Canadian Natural Resources Limited's Annual General Meeting of the Shareholders will be held on Thursday, May 4, 2006 at 3:00 p.m. Mountain Daylight Time at the Metropolitan Conference Centre, Calgary, Alberta. All shareholders are invited to attend.

For further information, please contact:

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Chairman

JOHN G. LANGILLE
Vice-Chairman

STEVE W. LAUT
President &
Chief Operating Officer

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

COREY B. BIEBER
Vice-President
Investor Relations