Q2

Six Months Ended
June 30, 2004

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES RECORD PRODUCTION AND CASH FLOW FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2004

In commenting on second quarter 2004 results, Canadian Natural's Chairman, Allan Markin, stated "This was yet another milestone quarter for Canadian Natural as we continue to execute our defined plan, achieving record results. We have set quarterly records for crude oil production, natural gas production and cash flow from operations. In 2004, we expect average annual production growth of 11 to 14% and entry to exit growth in excess of 15%."

Canadian Natural's President, John Langille, in commenting on the financial results of the second quarter stated "We continue to show discipline in our financial matters. Two large asset acquisitions have been completed in Canada with a third, in the North Sea, now expected to close in the third quarter. All three of these acquisitions meet our internal return targets and provide exploitation upside. In addition, they will have the benefit of providing additional free cash flow generation during the construction years of the Horizon Oil Sands Project – making us financially stronger and further increasing our capability to retain a 100% interest in the Project. Based on today's strip commodity prices, our debt to book capitalization is expected to exit 2004 at under 30%. We continue to finalize the engineering and design work for the Project and are in the process of receiving and reviewing the fixed bid offers in order to help achieve the level of cost comfort required for our Board of Directors to approve the Project later this year."

Canadian Natural's Chief Operating Officer, Steve Laut, in commenting on 2004 operations year to date stated "We are pleased to have achieved quarterly production that was at the high end of our guidance for both crude oil and NGLs and natural gas. In addition to quarterly organic production growth of 5%, the property acquisition we completed at the start of the quarter added 3% to quarterly growth. We have dropped operating costs on the East Alberta heavy crude oil assets acquired in the first quarter of 2004 by about $0.60 per barrel through leveraging our vast infrastructure. The acquisition of natural gas properties in Northeast British Columbia also looks to have additional upside on a shallow natural gas play we discovered late last year. The Notikewin geology trends on to this land, providing significant upside in addition to the deep foothills potential acquired."

HIGHLIGHTS OF THE SECOND QUARTER

- Record quarterly crude oil and NGLs production of 275 mbbl/d before royalties (249 mbbl/d net of royalties). This represents an increase of 5% over first quarter 2004 production and 14% over second quarter 2003 production.

- Record quarterly natural gas sales of 1,452 mmcf/d before royalties (1,156 mmcf/d net of royalties), representing 47% of equivalent production during the quarter. This includes North American quarterly growth of 13% over first quarter 2004, representing 7% organic growth and 6% from the assets acquired at the start of the second quarter.

- Record quarterly equivalent production of 517 mboe/d before royalties (442 mboe/d net of royalties), representing the third consecutive quarter of overall production growth, an 8% increase from the first quarter and a 12% increase over the second quarter of the prior year.

- Record quarterly cash flow of $930 million ($3.47 per common share) compared with $762 million ($2.84 per common share) in the second quarter of 2003 and $848 million ($3.16 per common share) in the previous quarter.

- Net earnings of $259 million ($0.97 per common share) compared with $525 million ($1.96 per common share) for the second quarter of 2003 and $258 million ($0.96 per common share) in the previous quarter. Adjusted net earnings from operations, a non Generally Accepted Accounting Principle ("GAAP") term, amounted to $364 million ($1.36 per common share) compared with $256 million ($0.96 per common share) for the second quarter of 2003 and $339 million ($1.27 per common share) in the previous quarter.

- Successfully completed the acquisition of natural gas assets located in the Company's core region of Northeast British Columbia and an extension of its core region in the Foothills area of Northwest Alberta for $280 million. The acquisition increases ownership in the Ladyfern area and adds a significant number of additional shallow gas drilling opportunities as well as providing Foothills exploration acreage to augment Canadian Natural's existing holdings in the region.

- Commenced production from a new phase of the Primrose in-situ thermal crude oil development late in the quarter. Production is expected to ramp up during the second half of 2004 with exit volumes expected to reach between 48 and 51 mbbl/d.

- Capital expenditures of $844 million, reflecting second quarter drilling activities and the natural gas property acquisition. During the quarter, Canadian Natural drilled 132 wells, including 86 successful natural gas wells.

- Completed the subdivision of its Common Shares on the basis of two for one.

- Increased the quarterly dividend by 33% to $0.10 per common share commencing with the April 1, 2004 payment.

- Continued with the repurchase of 800,000 common shares under its Normal Course Issuer Bid.

- Debt to book capitalization at the end of the second quarter was 35%, which reflects the capital program in the first half of 2004. The first half capital program is higher than for the balance of 2004 due to a larger portion of activities occurring during the winter months. In the current pricing environment, debt to book capitalization would exit 2004 at less than 30%.

- Negotiated the acquisition of certain light crude oil producing properties in the Central North Sea. The acquisition is expected to close during the third quarter and will add approximately 16,000 boe/d and includes additional infrastructure including a fixed platform, a Floating Production Vessel (FPV) and subsea equipment.

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 for each of the periods reported. Adjusted net earnings from operations is a non-GAAP term that the Company utilizes to evaluate its performance and that of its business segments.

($ millions, except per common share amounts)

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Net earnings attributable to common shareholders as reported	**$ 259**	$ 258	$ 525	**$ 517**	$ 952
Unrealized foreign exchange loss (gain)[1]	**26**	37	(87)	**63**	(183)
Unrealized foreign exchange loss (gain) on preferred securities[1]	**2**	1	(7)	**3**	(14)
Unrealized risk management activities[2]	**47**	68	-	**115**	-
Effect of statutory tax rate changes on future income tax liabilities[3]	**-**	(66)	(247)	**(66)**	(247)
Stock-based compensation expense[4]	**30**	41	72	**71**	72
Adjusted net earnings from operations attributable to common shareholders	**$ 364**	$ 339	$ 256	**$ 703**	$ 580
Per share – basic[5]	**$ 1.36**	$ 1.27	$ 0.96	**$ 2.62**	$ 2.17
– diluted[5]	**$ 1.36**	$ 1.26	$ 0.94	**$ 2.62**	$ 2.13

(1) *Unrealized foreign exchange gains and losses result primarily from the translation of long-term debt and preferred securities to period end exchange rates and are immediately recognized in net earnings attributable to common shareholders.*

(2) *Effective January 1, 2004, the Company adopted a new accounting standard whereby financial instruments not designated as hedges are valued at fair value on its balance sheet, with changes in fair value, net of taxes, flowing through earnings. The realized value may be different than reflected in these financial statements due to changes in the underlying items hedged, primarily crude oil and natural gas prices.*

(3) *All substantively enacted adjustments in applicable income tax rates are applied to underlying assets and liabilities on the Company's balance sheet in determining future income tax assets and liabilities. The impact of these tax rate changes is recorded in net earnings during the period the legislation is substantively enacted. During the first quarter of 2004, a Canadian province introduced legislation to reduce its corporate income tax rate. During 2003, the Canadian Government introduced several income tax changes, including rate reductions, for the resource industry. Also during 2003, a Canadian Province introduced legislation to reduce its corporate income tax rate.*

(4) *Commencing with the second quarter of 2003, the Company modified its employee stock option plan to provide for a cash payment option. The intrinsic value of the outstanding stock options is recorded as a liability on the Company's balance sheet and quarterly changes in the intrinsic value, net of taxes, flow through earnings.*

(5) *Restated to reflect two-for-one share split in May 2004.*

OPERATIONS REVIEW

Production

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 crude oil, Pelican Lake crude oil, primary heavy crude oil and thermal heavy crude oil.

Record average natural gas production levels in the second quarter of 2004 represents an increase of 12% over the previous quarter of 2004 and meets the Company's target of 5% growth rate for the trailing twelve month period. The second quarter increase also reflects seasonal peaks caused by the first quarter emphasis on drilling natural gas in winter-access only areas. Current production volumes are in excess of 1.4 bcf/d of natural gas.

Record average crude oil and NGLs production during the second quarter of 2004 totaled 275 mbbl/d. That represents a 5% increase over the previous quarter of 2004 and a 14% increase over the same period in 2003, reflecting drilling successes and accretive acquisitions. Current production volumes are in excess of 290 mbbl/d of crude oil and NGLs.

The Company's production composition, before royalties, is as follows:

	Q2 2004		Q1 2004		Q2 2003	
	mboe/d	%	mboe/d	%	mboe/d	%
Natural gas	**241.9**	**47**	215.6	45	220.9	48
Light crude oil and NGLs	**118.7**	**23**	117.1	25	112.0	24
Pelican Lake crude oil	**19.6**	**4**	19.9	4	25.9	6
Primary heavy crude oil	**101.4**	**19**	89.8	19	63.8	14
Thermal heavy crude oil	**35.7**	**7**	34.5	7	38.9	8
Total	**517.3**	**100**	476.9	100	461.5	100

The Company currently expects 2004 production levels, before royalties, to average 1,371 to 1,393 mmcf/d of natural gas and 279 to 290 mbbl/d of crude oil and NGLs. Third quarter 2004 production guidance, before royalties, for natural gas is 1,375 to 1,413 mmcf/d of natural gas and 284 to 307 mbbl/d of crude oil and NGLs. The production guidance includes light crude oil production from two new blocks acquired in the North Sea. As a result of this acquisition, and other capital reallocations for the second half of the year, the Company has determined its 2004 capital expenditure program will amount to between $3.65 and $3.85 billion. This compares to anticipated cash flow based on current market pricing of $3.9 to $4.0 billion. Detailed guidance on production levels and operating costs can be found on the Company's website (www.cnrl.com/investor/guidance.htm).

Drilling Activity (number of wells)

	Six Months Ended June 30			
	2004		2003	
	Gross	**Net**	Gross	Net
Crude oil	**196**	**185**	292	273
Natural gas	**492**	**444**	319	299
Dry	**77**	**72**	31	30
Subtotal	**765**	**701**	642	602
Stratigraphic test / service wells	**271**	**270**	373	371
Total	**1,036**	**971**	1,015	973
Success rate (excluding strat test / service wells)		**90%**		95%

During the quarter, Canadian Natural drilled 132 net wells, including 2 stratigraphic test and service wells. As much of Canadian Natural's natural gas regions are winter-access only, the Company's natural gas drilling is concentrated in the winter months. Hence the second quarter is typified by peak production levels and a significant reduction in drilling activity. The spring and summer drilling program is typically comprised of heavy crude oil drilling as well as shallow natural gas drilling in South Alberta. During the second quarter, Canadian Natural drilled 87 net wells targeting natural gas, including 2 wells in Northeast British Columbia and 13 wells in Northwest Alberta. The Northeast British Columbia and Northwest Alberta core regions represent the high growth potential natural gas areas of the Company.

The Company also drilled 43 net wells targeting crude oil and NGLs during the second quarter 2004. These wells were concentrated in the Company's crude oil region of North Alberta where 11 primary heavy crude oil and 14 Pelican Lake wells were drilled. Also included in this figure were 12 high-pressure horizontal thermal crude oil wells that were drilled and completed at Primrose as part of the 2004 development strategy of the area.

The total success rate for Canadian Natural's drilling program was 98% for the quarter and 90% for the first half, excluding stratigraphic test and service wells. These excellent results reflect the disciplined approach that the Company takes in its exploitation and development programs and the strength of its asset base.

Pricing

Detailed reviews of benchmark pricing and sensitivity to product pricing, currency exchange, and interest rates are provided in Management's Discussion and Analysis. Product pricing for both crude oil and natural gas increased during the second quarter of 2004 when compared to either the previous quarter or the corresponding quarter of 2003. Heavy crude oil differentials increased 17% to $11.63 in the second quarter reflecting higher light crude oil prices. The long term heavy crude oil differential has approximated 30% of WTI benchmark price and during the second quarter, averaged 30% compared to 28% in the first quarter. It is anticipated that the differential will narrow both in absolute and percentage terms in the third quarter based on current indicative pricing.

Canadian Natural continues to deliver on its heavy crude oil marketing strategy and in particular its bitumen diluted with synthetic light crude oil or "Synbit" product. The Company is currently marketing 50 mbbl/d of Synbit to refiners located in the U.S. Midwest and plans to expand this effort throughout 2004 to build a solid new market for heavy and synthetic crudes. This incremental market will enhance Canadian Natural's ability to profitably expand heavy crude oil production. As part of an industry initiative to develop new blends of western Canadian crude oils, Canadian Natural expects to have capacity to blend up to 140,000 bbl/d of Synbit and other crude oil blends by the end of 2004.

The Company utilizes risk management instruments on a portion of its production in an effort to reduce volatility and provide greater certainty that operating cash flows are available to fund capital expenditures. Generally, costless collars and puts are utilized against benchmark commodity prices as well as currency exposures. The details of these financial risk management instrument positions are reported in note 11 of the consolidated financial statements. In accordance with new financial reporting standards, Canadian Natural also records mark-to-market valuations of economic price risk management instruments not designated as hedges for accounting purposes applicable to future production. These amounts represent valuations at the balance sheet date should the Company wish to monetize the risk management positions. However, it is the Company's intention to maintain these risk management positions over the production periods noted and therefore the ultimate cost or benefit of the program is indeterminable and will be realized over time. These risk management positions and the mark-to-market are detailed in Management's Discussion and Analysis.

Indicative commodity prices as at August 3, 2004 include a near month contract reference WTI price of US$44.13/bbl, a NYMEX natural gas price of US$5.83/mmbtu and a Lloyd Blend heavy crude oil differential of US$11.10/bbl. The Bank of Canada noon day exchange rate for this date was US$0.7581 equals C$1.00.

ACTIVITY BY CORE REGION

	Net Undeveloped Land as at Jun 30, 2004	**Drilling Activity Six months ended Jun 30, 2004**
	(thousands of net acres)	(net wells)
Northeast British Columbia	**1,588**	**178**
Northwest Alberta	**1,709**	**89**
North Alberta	**6,432**	**377**
South Alberta	**641**	**128**
Southeast Saskatchewan	**129**	**11**
Horizon Oil Sands Project	**117**	**180**
United Kingdom North Sea	**567**	**7**
Offshore West Africa	**943**	**1**
	12,126	**971**

North American Natural Gas

Canadian Natural's North American natural gas production and development is focused in four core regions in which the Company dominates the land base and infrastructure. Production during the second quarter increased to average 1,389 mmcf/d, an increase of 13% or 159 mmcf/d from the first quarter of 2004 and 9% or 111 mmcf/d from the second quarter of 2003. Production increases reflect a successful development drilling program as well as the impact of the acquisition of certain resource properties producing approximately 68 mmcf/d of natural gas located in Northeast British Columbia and Northwest Alberta. The properties include a further ownership interest in the Ladyfern natural gas field, complementing Canadian Natural's existing holdings. The acquisition also provided a strong land position, facilitating the expansion of existing Gething and Notikewin plays as well as an expanded presence in the Foothills areas of Alberta and British Columbia. The Foothills area is characterized by large, high-rate, deep prospects and are considered higher risk and higher reward targets. The Company has a team of exploration specialists that will take advantage of the significant land base acquired to enhance the development of its deep natural gas exploration program, which is part of the long term natural gas portion of the defined plan.

Drilling success in the Northwest Alberta core region targeting cretaceous drilling zones in the Cardium, Cadomin, and other deep structures has driven production increases in the region. These successes ensure that the Company is on track to meet enhanced expectations for the year in terms of increased production and drilling locations. The Company has also been able to achieve continued drilling and facilities cost reductions, thereby increasing the number of economically viable drilling locations in the region.

Canadian Natural was also active in its traditional natural gas core regions of North Alberta and South Alberta where it dominates a vast land base, drilling 23 and 49 wells targeting natural gas respectively in the second quarter. The Company continues to develop its resources in these regions, which account for approximately 40 to 45% of daily corporate natural gas production. During the summer months the Company expects to drill approximately 75 shallow natural gas wells in South Alberta.

Consistent with historical results, the summer natural gas drilling program will not be sufficient to offset normal production declines from winter access fields in other core regions; hence the Company is expecting lower third quarter volumes when compared with second quarter natural gas production levels.

North American Crude Oil and NGLs

Canadian Natural continues the development of its vast heavy crude oil resources. As has been previously articulated, the development of these assets will be brought on stream as the demand for heavy crude oil markets permit. In addition to the expansion of markets for Synbit, the Company is working with refiners to advance expansions of heavy crude oil conversion capacity of refineries in the Midwest United States, and is working with pipeline companies to develop new capacity to the Canadian west coast where crude cargoes could be sold on a world-wide basis. Over the long term, as these opportunities come to fruition, Canadian Natural will accelerate development of its bitumen resources. As part of this development plan, the Company is continuing with its Primrose thermal project which includes the Primrose North expansion project, drilling additional wells in the Primrose South project augmenting existing production, and converting all of the existing wells from low pressure to high pressure steaming. At Primrose South, drilling of the two new phases that commenced in 2003 was completed. Steaming of these new phases is underway and production commenced in late June, meeting time, budget and volumetric expectations.

In the second quarter, the Company drilled 11 heavy crude oil wells, 14 Pelican Lake crude oil wells and 12 high-pressure cyclic steam thermal crude oil wells at Primrose. During the quarter, operating cost reductions of approximately $0.60/bbl were effected on the heavy crude oil properties acquired in February, 2004. Cost reductions were achieved through leveraging the Company's large infrastructure, particularly its sand handling capabilities and the use of the ECHO heavy crude oil pipeline. In addition, approximately 300 new well locations and over 400 well recompletion opportunities have been identified on these lands and have been added into project inventory.

The Pelican Lake enhanced crude oil recovery project also continues on track. This project seeks to significantly increase recovery efficiency on this vast blanket sand in North Alberta. Quarterly production declines were abated through drilling activity and initial stages of waterflood response.

Horizon Oil Sands Project

Canadian Natural continues to target an acceptable level of comfort of forecasted capital costs and execution planning for the Horizon Oil Sands Project ("Horizon Project") for fall 2004. The Company's approach is to have a higher level of project definition and detailed engineering than has been typical for predecessor projects. This, along with Canadian Natural retaining the role as managing contractor and breaking the project into numerous manageable pieces that can be individually bid out to different engineering and construction firms, represents a significant departure from past industry norms. This strategy will award contracts on a significant portion of the Engineering, Procurement and Construction of Horizon under a lump sum or fixed cost basis, which will permit the Company to obtain a higher degree of cost certainty and risk management. Once acceptable certainty of forecasted capital costs is obtained, the Company's management will be in a position to recommend to the Company's Board of Directors the sanctioning of the project. While completion on a timely basis is important, the Company views determination of forecasted costs to be a higher priority and will allow some flexibility in dates in order to control costs. It is anticipated that Board of Directors approval will be sought sometime in the fourth quarter of 2004.

During the second quarter of 2004, work on the third phase of front-end engineering, Engineering Design Specification, continued and some site preparation was completed. Additionally, bid packages representing approximately 40% of expected phase one costs were sent out for lump sum Engineer-Procure-Construct bids. In addition, purchase orders were awarded for the long-lead equipment items representing $65 million on a lump sum basis. For phase one, a total of 145 major bid packages for contracts and purchase orders are expected to be released, of which over 90% have been issued for tender.

The Company currently employs 216 experienced staff and 440 contract professionals on this project. As owner manager, Canadian Natural will develop and execute this plan ensuring delivery of the project on budget.

North Sea

Canadian Natural uses its mature basin expertise and remains excited about the exploitation prospects that exist in the North Sea and will continue to target accretive acquisitions with exploitation upside potential. During the quarter its successful infill drilling, recompletion and waterflood optimization programs at the Ninian and Murchison platforms continued and resulted in production increases of approximately 5 mbbl/d in June. At Murchison, water injection has been increased by 40 mbbl/d. Near pool exploration target, Playfair, is expected to be drilled during the third quarter.

Also during the quarter Canadian Natural continued plans for its natural gas reinjection project at the Banff Field in the Central North Sea. This project is expected to increase overall reservoir recovery by approximately 17 mmbbl net to Canadian Natural, but will result in lower natural gas production volumes during the latter half of 2004.

Finally, during the quarter the Company negotiated the acquisition of 16 mboe/d of light crude oil producing properties in the Central North Sea. The acquired properties comprise operated interests of 88.74% in the T-Block (Tiffany, Toni and Thelma fields) and 68.68% to 75.29% interests in the B-Block (Balmoral, Stirling and Glamis fields), together with associated production facilities, including a fixed platform, FPV and an adjacent exploration acreage which is anticipated to add further future development opportunities.

Offshore West Africa

The development of the Baobab Field offshore Côte d'Ivoire continued on time and on budget for Canadian Natural's first deep water development. The development will include eight production wells, three water injection wells and related subsea infrastructure. To date, production testing on the P3 well exceeded expectations and is now expected to flow at between 10 to 14 mbbl/d when it comes on production in mid 2005. The P4 well is expected to flow at 15 to 18 mbbl/d, up from the initial plan of 10 mbbl/d. An additional two wells have been drilled to the top of the reservoir with one water injection well having been drilled to final total depth, confirming reservoir quality and production / injection expectations. Additionally, during the quarter, five production trees were delivered with the remainder on schedule and all four manifold structures and infield umbilicals completed. Crude oil will be produced to a Floating Production Storage and Offtake ("FPSO") vessel currently being fabricated in Singapore.

At East Espoir, an additional three wells are scheduled for drilling in early 2005 as 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. The planned development of the nearby West Espoir Field has been sanctioned by Partners during the second quarter with various components out for bid. Current plans provide for approximately 8 mbbl/d of crude oil and 30 mmcf/d of natural gas production net to Canadian Natural commencing spring 2006 through existing FPSO facilities.

Delineation drilling of the Acajou satellite pool discovered in 2003 is expected for the fourth quarter of 2004. Depending on the size of reserves delineated, Acajou could be tied into the Espoir FPSO or if large enough, justify its own FPSO. Additional geological reviews on other Canadian Natural lands is yielding exploration targets, one of which will be drilled during 2005.

Finally, Canadian Natural continues to reprocess seismic on Block 16 located offshore Angola to optimize its next drilling location. The incorporation of data from the unsuccessful well drilled in late 2003 will help reduce exploration risks on the next well, currently expected to be drilled in 2005. Block 16 represents a high risk / high impact exploration development for the Company in one of the most prolific crude oil regions of the world.

FINANCIAL REVIEW

Canadian Natural is committed to maintaining its strong financial position in order to withstand volatile crude oil and natural gas commodity prices and the operational risks inherent in the crude oil and natural gas business environment. The Company continues to build the necessary financial capacity to maximize ownership in the Horizon Project.

During the first half of 2004, strong operational results and product pricing enabled the Company to maintain debt levels at approximately 35% of book capitalization despite significant first half capital expenditures and property acquisitions aggregating $2.3 billion. Corporate debt to cash flow was approximately 1.1 times versus 0.9 times recorded at year end 2003, while debt to EBITDA was 1.0 times compared with 0.8 times at December 31, 2003. Based upon current strip pricing, it is anticipated that debt to book capitalization and debt to EBITDA will exit 2004 at less than 30% and 1.0 times respectively.

The Company has used excess cash flows derived from higher than expected commodity prices to selectively acquire future cash flow generating properties in its core regions. These targeted acquisitions provide relatively quick repayment of initial investments and will provide additional free cash flow generation capability during the construction years of Horizon while still achieving targeted returns. The Petrovera acquisition, the acquisition of natural gas properties and the acquisition of properties in the central North Sea all meet these reinvestment criteria and further enhance Canadian Natural's ability to maximize its ownership in the Horizon Project. This expansion of conventional assets also helps reduce the sole project risk exposure associated with this major development project.

In order to increase the liquidity of its common shares, the Company and its shareholders agreed in May 2004 to subdivide its issued and outstanding common shares on a two-for-one basis. At June 30, 2004, there were 267,910,000 common shares issued and outstanding. During the first half of 2004, Canadian Natural also utilized its Normal Course Issuer Bid program administered through the facilities of the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE") in order to repurchase and cancel 800,000 common shares for a total cost of $30 million ($37.60 per common share).

The Board of Directors declared a quarterly dividend of $0.10 per common share payable October 1, 2004 to shareholders of record on September 17, 2004. The quarterly dividend was increased from $0.075 per common share, representing a 33% increase and became effective April 1, 2004.

Special note regarding 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: the general economic and business conditions which will, among other things, impact demand for and market prices of the Company’s products; the foreign currency exchange rates; the economic conditions in the countries and regions in which the Company conducts business; the political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; the industry capacity; the ability of the Company to implement its business strategy, including exploration and development activities; the impact of competition, availability and cost of seismic, drilling and other equipment; the ability of the Company to complete its capital programs; the 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; the operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas; the availability and cost of financing; the success of exploration and development activities; the timing and success of integrating the business and operations of acquired companies; the production levels; the uncertainty of reserve estimates; the actions by governmental authorities; the government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations); the 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 management’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. The Company assumes no obligation to update forward-looking statements should circumstances or management’s estimates or opinions change.

Special note regarding non-GAAP financial measures

Management's Discussion and Analysis includes references to financial measures commonly used in the oil and gas industry, such as cash flow, cash flow per share 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 activity). These financial measures are not defined by generally accepted accounting principles (“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 the performance of the Company and its business segments. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with Canadian GAAP, as an indication of the Company's performance.

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 (“Canadian Natural” or the “Company”), should be read in conjunction with the unaudited interim consolidated financial statements for the three and six months ended June 30, 2004 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2003.

All dollar amounts, except per common share data, are referenced in millions of Canadian dollars, except where noted otherwise. The calculation of barrels of oil equivalent (“boe”) is based on a conversion ratio of 6 thousand cubic feet of natural gas to one barrel of 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 the Company’s interest before royalties, and realized prices exclude the effect of hedging gains and losses, except where noted otherwise.

ACQUISITION

In February, 2004, the Company acquired certain resource properties in its North Alberta core region, collectively known as the Petrovera Partnership (“Petrovera”), for $471 million. At the time of the acquisition, production from the acquired properties was approximately 27,500 bbl/d of heavy crude oil and 9 mmcf/d of natural gas. Strategically, the acquisition fits with the Company’s objective of dominating its core areas and related infrastructure. The Company achieved cost reductions through synergies with its existing facilities, including additional throughput in its 100% owned ECHO Pipeline. The acquisition is included in the results of operations commencing February 2004.

FINANCIAL HIGHLIGHTS
($ millions, except per common share amounts)

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003(1)	**Jun 30 2004**	Jun 30 2003(1)
Revenue	**$ 1,865**	$ 1,638	$ 1,502	**$ 3,503**	$ 3,342
Net earnings attributable to common shareholders(2)	**$ 259**	$ 258	$ 525	**$ 517**	$ 952
Per common share – basic(3)	**$ 0.97**	$ 0.96	$ 1.96	**$ 1.93**	$ 3.56
– diluted(3)	**$ 0.97**	$ 0.96	$ 1.89	**$ 1.93**	$ 3.43
Cash flow from operations attributable to common shareholders(4)	**$ 930**	$ 848	$ 762	**$ 1,778**	$ 1,668
Per common share – basic(3)	**$ 3.47**	$ 3.16	$ 2.84	**$ 6.64**	$ 6.22
– diluted(3)	**$ 3.47**	$ 3.14	$ 2.79	**$ 6.64**	$ 6.09
Business Combination	**$ -**	$ 471	$ -	**$ 471**	$ -
Capital expenditures, net of dispositions	**$ 844**	$ 1,022	$ 410	**$ 1,866**	$ 1,223

(1) *Restated for change in accounting policy (see consolidated financial statements note 2).*

(2) *After dividend and revaluation of preferred securities.*

(3) *Restated to reflect two-for-one share split in May 2004.*

(4) *Cash flow from operations attributable to common shareholders is a non-GAAP term that represents net earnings attributable to common shareholders adjusted for non-cash items. The Company evaluates its performance and that of its business segments based on earnings and cash flow from operations. The Company considers cash flow a key measure as it demonstrates the Company's ability and the ability of its business segments to generate the cash flow necessary to fund future growth through capital investment and to repay debt.*

	Three Months Ended			*Six Months Ended*	
($ millions)	***Jun 30 2004***	*Mar 31 2004*	*Jun 30 2003*	***Jun 30 2004***	*Jun 30 2003*
Net earnings attributable to common shareholders	***$ 259***	*$ 258*	*$ 525*	***$ 517***	*$ 952*
Non-cash items:					
Future tax on dividend on preferred securities	***(1)***	*(1)*	*(1)*	***(2)***	*(2)*
Revaluation of preferred securities, net of tax	***2***	*1*	*(7)*	***3***	*(14)*
Stock-based compensation expense	***50***	*56*	*105*	***106***	*105*
Depletion, depreciation and amortization	***426***	*389*	*370*	***815***	*731*
Accretion of asset retirement obligation	***10***	*11*	*15*	***21***	*30*
Unrealized risk management activities	***70***	*102*	*-*	***172***	*-*
Unrealized foreign exchange loss (gain)	***33***	*46*	*(109)*	***79***	*(228)*
Deferred petroleum revenue tax (recovery)	***(3)***	*4*	*4*	***1***	*7*
Future income tax expense (recovery)	***84***	*(18)*	*(140)*	***66***	*87*
Cash flow from operations attributable to common shareholders	***$ 930***	*$ 848*	*$ 762*	***$ 1,778***	*$ 1,668*

The Company achieved record levels of crude oil and natural gas production, reporting 517,343 barrels of crude oil equivalent production per day in the three months ended June 30, 2004 and 497,143 barrels of crude oil equivalent per day for the first half of 2004. The Company recorded strong levels of net earnings and cash flow for the six and three months ended June 30, 2004 by continuing to follow its defined growth strategy to create shareholder value. Cash flow increased 7% to $1,778 million and 22% to $930 million from the comparable periods in 2003. The increase in cash flow was a result of increased production volumes and higher product prices for crude oil and NGLs. Net earnings decreased 46% to $517 million and 51% to $259 million for the six and three months ended June 30, 2004 from the comparable periods in the prior year. The decrease in net earnings was a result of the recognition in 2004 of an unrealized expense related to the mark-to-market of the Company's undesignated financial instruments, an unrealized foreign exchange loss on the Company's US dollar denominated debt in 2004 versus an unrealized gain in 2003, and the impact of Federal corporate income tax changes in 2003, partially offset by a larger effect of Alberta corporate tax rate reductions in 2004 then in 2003.

OPERATING HIGHLIGHTS

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Crude oil and NGLs ($/bbl, except daily production)					
Daily production (bbl/d)	**275,398**	261,286	240,607	**268,342**	239,092
Sales price[1]	**$ 36.72**	$ 34.21	$ 30.66	**$ 35.49**	$ 34.96
Royalties	**3.15**	2.91	2.78	**3.03**	3.17
Production expense	**9.92**	9.58	10.80	**9.75**	10.79
Netback	**$ 23.65**	$ 21.72	$ 17.08	**$ 22.71**	$ 21.00
Natural gas ($/mcf, except daily production)					
Daily production (mmcf/d)	**1,452**	1,294	1,325	**1,373**	1,318
Sales price [1]	**$ 6.64**	$ 6.31	$ 6.25	**$ 6.48**	$ 6.99
Royalties	**1.38**	1.27	1.35	**1.33**	1.56
Production expense	**0.66**	0.65	0.59	**0.65**	0.58
Netback	**$ 4.60**	$ 4.39	$ 4.31	**$ 4.50**	$ 4.85
Barrels of oil equivalent ($/boe, except daily production)					
Daily production (boe/d)	**517,343**	476,944	461,455	**497,143**	458,719
Sales price[1]	**$ 38.20**	$ 35.88	$ 33.91	**$ 37.09**	$ 38.32
Royalties	**5.55**	5.03	5.32	**5.30**	6.13
Production expense	**7.12**	7.02	7.34	**7.08**	7.31
Netback	**$ 25.53**	$ 23.83	$ 21.25	**$ 24.71**	$ 24.88

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

BUSINESS ENVIRONMENT

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
WTI benchmark price (US$/bbl)	**$ 38.34**	$ 35.16	$ 28.90	**$ 36.75**	$ 31.34
Dated Brent benchmark price (US$/bbl)	**$ 35.42**	$ 31.98	$ 26.02	**$ 33.70**	$ 28.75
Differential to LLB blend (US$/bbl)	**$ 11.63**	$ 9.92	$ 7.18	**$ 10.77**	$ 7.64
Condensate benchmark price (US$/bbl)	**$ 39.17**	$ 35.99	$ 29.88	**$ 37.58**	$ 32.08
NYMEX benchmark price (US$/mmbtu)	**$ 5.97**	$ 5.69	$ 5.48	**$ 5.83**	$ 6.06
AECO benchmark price (C$/GJ)	**$ 6.45**	$ 6.26	$ 6.63	**$ 6.35**	$ 7.08
US / Canadian dollar average exchange rate (US$)	**$ 0.74**	$ 0.76	$ 0.72	**$ 0.75**	$ 0.69

World crude oil prices continued to remain strong in the first half of 2004 due to continued strong world-wide demand. World crude oil prices have also been impacted by the geopolitical uncertainty in several areas of the world. West Texas Intermediate ("WTI") averaged US$36.75 per bbl for the six months ended June 30, 2004, up 17% compared to US$31.34 per bbl in the comparable period in the prior year. WTI averaged US$38.34 per bbl in the second quarter of 2004, up 33% from US$28.90 per bbl in the comparable period in 2003, and up 9% from US$35.16 per bbl in the prior quarter. The impact of the higher WTI price was reduced as a result of wider heavy crude oil differentials, which increased 41% to US$10.77 per bbl and 62% to US$11.63 per bbl for the six months and three months ended June 30, 2004 from the comparable periods in 2003. The heavy crude oil differentials increased 17% from US$9.92 per bbl in the prior quarter. Realized crude oil prices were also impacted by the strengthening Canadian dollar and the higher costs associated with condensate used for blending with heavy crude oil. The increase in the condensate price was mainly due to additional bitumen supply caused by a major upgrader turnaround in the first half of 2004.

North America natural gas prices remained strong due to concerns around supply. AECO natural gas prices decreased 10% to average $6.35 per GJ for the six months ended June 30, 2004 from $7.08 per GJ in the comparable period in 2003. NYMEX natural gas prices decreased 4% to average US$5.83 per mmbtu for the six months ended June 30, 2004 from US$6.06 per mmbtu in the comparable period in 2003. AECO natural gas prices decreased 3% to average $6.45 per GJ in the second quarter of 2004 from $6.63 per GJ in the comparable period in 2003, but increased 3% compared to $6.26 per GJ in the prior quarter. NYMEX natural gas prices increased 9% to average US$5.97 per mmbtu in the second quarter of 2004 from US$5.48 per mmbtu in the comparable period in 2003, and increased 5% from US$5.69 per mmbtu in the prior quarter.

PRODUCT PRICES

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Crude oil and NGLs ($/bbl)[1]					
North America	**$ 32.31**	$ 30.72	$ 28.42	**$ 31.54**	$ 32.17
North Sea	**$ 49.22**	$ 44.27	$ 37.08	**$ 46.81**	$ 43.44
Offshore West Africa	**$ 49.34**	$ 42.08	$ 34.34	**$ 45.63**	$ 35.88
Company average	**$ 36.72**	$ 34.21	$ 30.66	**$ 35.49**	$ 34.96
Natural gas ($/mcf)[1]					
North America	**$ 6.78**	$ 6.37	$ 6.39	**$ 6.59**	$ 7.13
North Sea	**$ 3.28**	$ 5.08	$ 2.21	**$ 4.17**	$ 3.12
Offshore West Africa	**$ 5.18**	$ 4.80	$ 5.09	**$ 4.97**	$ 4.61
Company average	**$ 6.64**	$ 6.31	$ 6.25	**$ 6.48**	$ 6.99
Percentage of revenue (excluding midstream revenue)					
Crude oil and NGLs	**51%**	52%	47%	**52%**	48%
Natural gas	**49%**	48%	53%	**48%**	52%

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

Realized crude oil prices increased 2% to average $35.49 per bbl for the six months ended June 30, 2004, up from $34.96 per bbl in the comparable period in 2003. The realized crude oil price increased 20% to average $36.72 per bbl in the second quarter of 2004, up from $30.66 per bbl in the comparable period in 2003 and up 7% from the previous quarter price of $34.21 per bbl. The increase in the realized crude oil prices is due mainly to higher world crude oil prices. The North America realized crude oil price for the first half of 2004 was also impacted by wider heavy crude oil differentials and higher condensate premiums compared to the comparable periods in the prior year. The North Sea realized crude oil price was impacted by a wider Brent differential to the WTI price in the first half of 2004. Offshore West Africa realized crude oil prices fluctuated due to changes to world crude oil prices.

The Company's realized natural gas price decreased 7% to average $6.48 per mcf for the six months ended June 30, 2004, down from $6.99 per mcf in the comparable period in 2003. The realized natural gas price increased 6% to $6.64 per mcf in the second quarter of 2004, up from $6.25 per mcf in the comparable period in 2003, and increased 5% from $6.31 per mcf in the prior quarter due to supply and demand fundamentals. Natural gas prices fluctuate from the comparable periods in the prior year due to fluctuations in the North America benchmark natural gas price.

A comparison of the price received for the Company's North American production is as follows:

	Q2 2004	Q1 2004	Q2 2003
Canadian Natural's Wellhead Price[1]			
Light crude oil and NGLs (C$/bbl)	**$ 44.83**	$ 40.69	$ 36.20
Pelican Lake crude oil (C$/bbl)	**$ 31.90**	$ 29.93	$ 26.48
Primary heavy crude oil (C$/bbl)	**$ 28.22**	$ 27.17	$ 25.64
Thermal heavy crude oil (C$/bbl)	**$ 27.67**	$ 26.57	$ 24.93
Natural gas (C$/mcf)	**$ 6.78**	$ 6.37	$ 6.39

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

DAILY PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Crude oil and NGLs (bbl/d)					
North America	**203,741**	192,151	175,232	**197,946**	174,144
North Sea	**60,105**	57,099	55,781	**58,602**	56,369
Offshore West Africa	**11,552**	12,036	9,594	**11,794**	8,579
Total	**275,398**	261,286	240,607	**268,342**	239,092
Natural gas (mmcf/d)					
North America	**1,389**	1,230	1,278	**1,310**	1,272
North Sea	**55**	54	40	**54**	41
Offshore West Africa	**8**	10	7	**9**	5
Total	**1,452**	1,294	1,325	**1,373**	1,318
Product mix					
Light crude oil and NGLs	**23%**	25%	24%	**24%**	24%
Pelican Lake crude oil	**4%**	4%	6%	**4%**	6%
Primary heavy crude oil	**19%**	19%	14%	**19%**	14%
Thermal heavy crude oil	**7%**	7%	8%	**7%**	8%
Natural gas	**47%**	45%	48%	**46%**	48%

DAILY PRODUCTION, net of royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Crude oil and NGLs (bbl/d)					
North America	**177,643**	168,052	151,619	**172,840**	150,823
North Sea	**59,983**	57,020	56,075	**58,501**	56,426
Offshore West Africa	**11,197**	11,670	9,318	**11,433**	8,320
Total	**248,823**	236,742	217,012	**242,774**	215,569
Natural gas (mmcf/d)					
North America	**1,094**	973	998	**1,033**	983
North Sea	**54**	54	40	**54**	41
Offshore West Africa	**8**	9	7	**9**	5
Total	**1,156**	1,036	1,045	**1,096**	1,029

Daily production and per barrel statistics are presented throughout the MD&A on a “before royalty” or “gross” basis. Production net of royalties is presented above for information purposes only.

The Company achieved record levels of production for both crude oil and natural gas in the second quarter of 2004. Production before royalties on a barrel of crude oil equivalent basis exceeded 517,000 bbl/d in the second quarter. The increases in production were due to the Company’s extensive capital expenditure program and recent acquisitions.

Total crude oil and NGLs production before royalties for the six and three months ended June 30, 2004 increased 12% or 29,250 bbl/d and 14% or 34,791 bbl/d respectively from the comparable periods in 2003. Crude oil and NGLs production before royalties for the second quarter increased 5% or 14,112 bbl/d from the prior quarter and was in line with the Company’s guidance of 264,000 to 282,000 bbl/d previously provided.

Crude oil and NGLs production before royalties in North America for the six and three months ended June 30, 2004 increased 14% or 23,802 bbl/d and 16% or 28,509 bbl/d respectively from the comparable periods in 2003 due mainly to the acquisition of Petrovera. Crude oil and NGLs production before royalties in the second quarter of 2004 increased 6% or 11,590 bbl/d from the prior quarter due to a full quarter of production from the Petrovera acquisition.

Crude oil production before royalties from the North Sea for the six and three months ended June 30, 2004 increased 4% or 2,223 bbl/d and 8% or 4,324 bbl/d respectively from the comparable periods in 2003. Crude oil production before royalties in the second quarter increased 5% or 3,006 bbl/d from the previous quarter. The increase in production was due to the ongoing drilling, recompletion and waterflood optimization program at the Ninian and Murchison Fields. In addition, crude oil production also increased due to recommencement of production from the Murchison Field following a shut down for planned maintenance on a natural gas compressor used to create gas lift for optimizing crude oil production.

Offshore West Africa crude oil production before royalties for the six and three months ended June 30, 2004 increased 37% or 3,215 bbl/d and 20% or 1,958 bbl/d respectively from the comparable periods in 2003. Crude oil production before royalties decreased 4% or 484 bbl/d from the prior quarter. The increase in production from the comparable periods in the prior year is due to the perforation of the upper zone of the East Espoir Field in the second quarter of 2003, and the completion of the fourth water injection well and two additional producing wells in 2003.

Natural gas production before royalties continues to represent the Company's largest product offering. Natural gas production before royalties for the six and three months ended June 30, 2004 increased 4% or 55 mmcf/d and 10% or 127 mmcf/d respectively from the comparable periods in 2003. The increase was a result of a successful natural gas drilling program and the acquisition of certain resource properties located in Northeast British Columbia and Northwest Alberta. Natural gas production before royalties in the second quarter of 2004 increased 12% or 158 mmcf/d from the prior quarter and was in line with the Company's guidance of 1,427 to 1,455 mmcf/d.

North America natural gas production before royalties for the six and three months ended June 30, 2004 increased 3% or 38 mmcf/d and 9% or 111 mmcf/d respectively from the comparable periods in 2003. North America production of natural gas increased as a result of the Petrovera acquisition, the acquisition of additional properties located in Northeast British Columbia and Northwest Alberta, and the focus on natural gas drilling. In addition, production of natural gas was impacted by the shut in of 11 mmcf/d of natural gas in the Athabasca Wabiskaw-McMurray oilsands area pursuant to the decision of the Alberta Energy and Utilities Board ("EUB") effective September 1, 2003. Based on the EUB Regional Geological Study, 5 mmcf/d of natural gas production previously shut in was brought back on production in 2004 and an additional 7 mmcf/d of natural gas production will be shut in effective July 1, 2004, bringing the total natural gas production shut in to 13 mmcf/d.

Natural gas production before royalties in the North Sea for the six and three months ended June 30, 2004 increased 32% or 13 mmcf/d and 38% or 15 mmcf/d respectively from the comparable periods in 2003 due to the increased working interests acquired in the Banff Field during 2003. Production of natural gas in the North Sea is expected to decline when the natural gas re-injection program on the Banff Field is implemented in the fourth quarter of 2004.

Natural gas production before royalties in Offshore West Africa for the six and three months ended June 30, 2004 increased 80% or 4 mmcf/d and 14% or 1 mmcf/d respectively over the comparable periods in 2003 due to the natural gas pipeline commencing operation in the third quarter of 2003.

The Company expects annual production levels before royalties to average 1,371 to 1,393 mmcf/d of natural gas and 279 to 290 mbbl/d of crude oil and NGLs in 2004. Third quarter 2004 production guidance before royalties is 1,375 to 1,413 mmcf/d of natural gas and 284 to 307 mbbl/d of crude oil and NGLs.

ROYALTIES

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Crude oil and NGLs ($/bbl)					
North America	**$ 4.14**	$ 3.85	$ 3.83	**$ 4.00**	$ 4.31
North Sea	**$ 0.10**	$ 0.06	$ (0.19)	**$ 0.08**	$ (0.04)
Offshore West Africa	**$ 1.52**	$ 1.28	$ 0.99	**$ 1.39**	$ 1.08
Company average	**$ 3.15**	$ 2.91	$ 2.78	**$ 3.03**	$ 3.17
Natural gas ($/mcf)					
North America	**$ 1.44**	$ 1.33	$ 1.40	**$ 1.39**	$ 1.61
North Sea	**$ -**	$ -	$ -	**$ -**	$ -
Offshore West Africa	**$ 0.16**	$ 0.15	$ 0.15	**$ 0.15**	$ 0.14
Company average	**$ 1.38**	$ 1.27	$ 1.35	**$ 1.33**	$ 1.56
Company average ($/boe)	**$ 5.55**	$ 5.03	$ 5.32	**$ 5.30**	$ 6.13
Percentage of revenue(1)					
Crude oil and NGLs	**9%**	8%	9%	**9%**	9%
Natural gas	**21%**	20%	22%	**20%**	22%
Boe	**15%**	14%	16%	**14%**	16%

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

North America crude oil and NGLs royalties fluctuated from both the comparable periods in 2003 and the prior quarter due to fluctuations in benchmark crude oil prices.

North Sea crude oil royalties were eliminated effective January 1, 2003. The North Sea royalty represents a gross overriding royalty on the Ninian Field. In the second quarter of 2003, the Company received a refund of royalties previously provided.

Natural gas royalties as a percentage of revenue fluctuate from both the comparable periods in 2003 and the prior quarter as a result of fluctuations in natural gas prices and the strong correlation of royalties to natural gas prices.

PRODUCTION EXPENSE

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Crude oil and NGLs ($/bbl)					
North America	**$ 8.91**	$ 8.65	$ 9.80	**$ 8.78**	$ 9.45
North Sea	**$ 13.84**	$ 13.26	$ 14.17	**$ 13.56**	$ 14.84
Offshore West Africa	**$ 7.43**	$ 7.09	$ 9.32	**$ 7.26**	$ 11.38
Company average	**$ 9.92**	$ 9.58	$ 10.80	**$ 9.75**	$ 10.79
Natural gas ($/mcf)					
North America	**$ 0.60**	$ 0.60	$ 0.56	**$ 0.60**	$ 0.56
North Sea	**$ 1.92**	$ 1.65	$ 1.45	**$ 1.78**	$ 1.27
Offshore West Africa	**$ 1.38**	$ 1.23	$ 1.45	**$ 1.30**	$ 1.79
Company average	**$ 0.66**	$ 0.65	$ 0.59	**$ 0.65**	$ 0.58
Company average ($/boe)	**$ 7.12**	$ 7.02	$ 7.34	**$ 7.08**	$ 7.31

North America crude oil and NGLs production expense for the six and three months ended June 30, 2004 decreased from the comparable periods in 2003. The decrease was due to the impact of lower natural gas prices on the costs of fuel used in the generation of steam in the Company's thermal heavy crude oil operations. The second quarter 2004 production expense per barrel increased from the previous quarter due to the impact of higher natural gas prices.

North Sea crude oil production varies on a per barrel basis from both the comparable periods in 2003 and the prior quarter due to the timing of maintenance work and the changes in production volumes on a relatively fixed cost base. Production expense in the second quarter of 2004 was impacted by reduced production as a result of the shut down of the largely fixed cost Murchison Platform for scheduled maintenance.

Offshore West Africa crude oil production costs are largely fixed in nature and therefore fluctuate on a per barrel basis from the comparable periods due to changes in production from the Espoir Field.

North America natural gas production expense per mcf for the six and three months ended June 30, 2004 increased marginally from the comparable periods in 2003 as a result of a general increase in service costs associated with increased industry activity and higher costs associated with colder weather experienced early in 2004.

MIDSTREAM ($ millions)

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Revenue	**$ 17**	$ 16	$ 14	**$ 33**	$ 32
Production expense	**5**	4	3	**9**	8
Midstream cash flow	**12**	12	11	**24**	24
Depreciation	**1**	2	2	**3**	4
Segment earnings before taxes	**$ 11**	$ 10	$ 9	**$ 21**	$ 20

The Company's midstream assets consist of three crude oil pipeline systems and an 84-megawatt cogeneration plant at Primrose where the Company has a 50% working interest. Approximately 80% of the Company's heavy crude oil production was transported to the 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 transport its own production volumes at reduced costs compared to other transportation alternatives as well as earn third party revenue. This transportation control enhances the Company's ability to control the full range of costs associated with the development and marketing of its heavy crude oil.

Revenue from the midstream assets for the six and three months ended June 30, 2004 increased from the comparable periods in 2003 due to higher electricity prices received in 2004.

DEPLETION, DEPRECIATION AND AMORTIZATION(2)

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003(1)	**Jun 30 2004**	Jun 30 2003(1)
Expense ($ millions)	**$ 425**	$ 387	$ 368	**$ 812**	$ 727
$/boe	**$ 9.01**	$ 8.91	$ 8.76	**$ 8.96**	$ 8.75

(1) *Restated for change in accounting policy (see consolidated financial statements note 2).*

(2) *Depletion, Depreciation and Amortization excludes depreciation on midstream assets.*

Depletion, Depreciation and Amortization ("DD&A") in the six and three months ended June 30, 2004 increased in total and per boe from the comparable periods in the prior year. The increase was due to higher finding and development costs associated with natural gas exploration in North America.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003(1)	**Jun 30 2004**	Jun 30 2003(1)
Expense ($ millions)	**$ 10**	$ 11	$ 15	**$ 21**	$ 30
$/boe	**$ 0.22**	$ 0.25	$ 0.36	**$ 0.23**	$ 0.36

(1) *Restated for change in accounting policy (see consolidated financial statements note 2).*

Accretion expense is the increase in the carrying amount of the asset retirement obligation due to the passage of time.

ADMINISTRATION EXPENSE

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Net expense ($ millions)	**$ 27**	$ 23	$ 23	**$ 50**	$ 41
$/boe	**$ 0.58**	$ 0.54	$ 0.56	**$ 0.56**	$ 0.50

Administration expense for the six and three months ended June 30, 2004 increased in total and on a per boe basis from the comparable periods in 2003 due to higher staffing levels associated with the Company's expanding asset base.

STOCK-BASED COMPENSATION

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Stock option plan ($ millions)	**$ 50**	$ 56	$ 105	**$ 106**	$ 105
Share bonus plan ($ millions)	**$ 2**	$ 5	$ -	**$ 7**	$ -
Total stock-based compensation expense ($ millions)	**$ 52**	$ 61	$ 105	**$ 113**	$ 105
$/boe	**$ 1.11**	$ 1.41	$ 2.49	**$ 1.26**	$ 1.26

The Company's Stock Option Plan (the "Option Plan") provides current employees, officers and directors (the "option holders") with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. The Option Plan balances the need for a long-term compensation program to retain employees with reducing the impact of dilution on current shareholders and the reporting of the expense 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 expensed. 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 stock-based compensation expense relating to the Company's Option Plan for the six months ended June 30, 2004 is $106 million ($71 million after tax). The liability is revalued quarterly to reflect changes in the market price of the Company's common shares and the net change is recognized in net earnings for the quarter.

The Share Bonus Plan incorporates share ownership in the Company by its employees without the granting of stock options or the dilution of current shareholders. Under the plan, a cash bonus may be awarded based on the Company's and the employee's performance and 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 period ended June 30, 2004, the Company has recognized $7 million ($4 million after tax) of compensation expense under the Share Bonus Plan.

The Company has recorded a liability at June 30, 2004 of $211 million (March 31, 2004 - $179 million; June 30, 2003 - $103 million) for expected cash settlements of stock options based on the intrinsic value of the outstanding stock options (the difference between the exercise price of the stock options and the market price of the Company's common shares). For the period ended June 30, 2004, the Company paid $45 million for stock options surrendered for cash settlement (March 31, 2004 - $35 million; June 30, 2003 - $1 million).

INTEREST EXPENSE

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003(1)	**Jun 30 2004**	Jun 30 2003(1)
Interest expense, net ($ millions)	**$ 46**	$ 43	$ 50	**$ 89**	$ 107
$/boe	**$ 0.98**	$ 0.98	$ 1.19	**$ 0.98**	$ 1.29
Average effective interest rate	**4.9%**	5.6%	6.0%	**5.3%**	6.0%

(1) *The comparative figures for prior year have been reclassified to conform to the presentation adopted in 2004.*

Interest expense for the six and three months ended June 30, 2004 was impacted by the Company prospectively adopting CICA Accounting Guideline 13, "Hedging Relationships" and EIC 128. As a result of the adoption of this accounting guideline, $19 million realized on certain of its fixed to floating interest rates swaps are included in risk management activities. Interest expense for the six and three months ended June 30, 2004 decreased from the comparable periods in 2003 due to an increase in the variable rate portion of debt at lower overall borrowing rates. Interest expense increased from the previous quarter due to higher debt levels associated with property acquisitions as well as the reduction of the first quarter working capital deficit.

RISK MANAGEMENT ACTIVITIES

On January 1, 2004, the Company prospectively adopted the CICA's Accounting Guideline 13, "Hedging Relationships" and EIC 128, "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments". Financial instruments that do not qualify as hedges under the Guideline or are not designated as hedges are recorded at fair value on the Company's consolidated balance sheet, with subsequent changes in fair value recognized in net earnings.

The Company utilizes various financial instruments to manage its commodity prices, foreign currency and interest rate exposures. These financial instruments are not used for trading purposes.

The Company enters into commodity price contracts to manage anticipated sales of crude oil and natural gas production in order to protect cash flow for capital expenditure programs. The Company also enters into foreign currency denominated financial instruments to manage future US Dollar denominated crude oil and natural gas sales. Gains or losses on these contracts are included in risk management activity.

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 principle amount on which the payments are based. Gains or loses on interest rate swap contracts designated as hedges are included in interest expense. Interest rate contracts not designated as hedges 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 non-current assets or liabilities on the consolidated balance sheets and amortized in 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 gain or loss is recognized in net earnings.

Adoption of this Guideline and EIC 128 had the following effects on the Company's financial statements for the six and three months ended June 30, 2004:

RISK MANAGEMENT ($ millions)

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Realized (loss) gain					
Crude oil and NGLs financial instruments	**$ (108)**	$ (37)	$ (9)	**$ (145)**	$ (96)
Natural gas financial instruments	**(2)**	-	(16)	**(2)**	(76)
Interest rate swaps	**10**	9	9	**19**	18
Total	**$ (100)**	$ (28)	$ (16)	**$ (128)**	$ (154)
Unrealized (loss) gain					
Crude oil and NGLs financial instruments	**$ (61)**	$ (106)	$ -	**$ (167)**	$ -
Natural gas financial instruments	**3**	(3)	-	**-**	-
Interest rate swaps	**(12)**	7	-	**(5)**	-
Total	**$ (70)**	$ (102)	$ -	**$ (172)**	$ -
Total	**$ (170)**	$ (130)	$ (16)	**$ (300)**	$ (154)

The effect of the realized loss (gain) on crude oil and natural gas financial instruments on the Company's average realized prices was:

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Crude oil and NGLs ($/bbl)	**$ 4.31**	$ 1.55	$ (0.39)	**$ 2.96**	$ (2.23)
Natural gas ($/mcf)	**$ 0.01**	$ -	$ (0.13)	**$ -**	$ (0.32)

The effect of the realized gain on interest rate swaps on the Company's interest expense was:

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Interest expense as per the financial statements	**$ 46**	$ 43	$ 50	**$ 89**	$ 107
Realized risk management (gain)	**(10)**	(9)	(9)	**(19)**	(18)
	$ 36	$ 34	$ 41	**$ 70**	$ 89
Average effective interest rate	**3.9%**	4.4%	4.9%	**4.2%**	4.9%

FOREIGN EXCHANGE ($ millions)

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Realized foreign exchange (gain) loss	**$ (10)**	$ (4)	$ 10	**$ (14)**	$ 11
Unrealized foreign exchange loss (gain)	**33**	46	(109)	**79**	(228)
	$ 23	$ 42	$ (99)	**$ 65**	$ (217)

The majority of the unrealized foreign exchange loss is related to the weakening Canadian dollar in relation to the US dollar. The Canadian dollar ended the second quarter of 2004 at US$0.75 compared to US$0.77 at December 31, 2003 (March 31, 2004 – US$0.76; June 30, 2003 – US$0.63).

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

TAXES ($ millions, except income tax rates)

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Taxes other than income tax					
Current	**$ 52**	$ 35	$ 20	**$ 87**	$ 45
Deferred	**(3)**	4	4	**1**	7
Total	**$ 49**	$ 39	$ 24	**$ 88**	$ 52
Current income tax					
North America – Current income tax	**$ 45**	$ 37	$ 12	**$ 82**	$ 28
North America – Large corporations tax	**1**	3	4	**4**	10
North Sea	**14**	23	1	**37**	16
Offshore West Africa	**4**	3	2	**7**	4
Total	**$ 64**	$ 66	$ 19	**$ 130**	$ 58
Future income tax expense (recovery)	**$ 84**	$ (18)	$ (140)	**$ 66**	$ 87
Effective income tax rate	**36.0%**	15.6%	(30.1%)	**27.3%**	13.4%

Taxes other than income tax includes current and deferred petroleum revenue tax ("PRT") and provincial capital taxes. PRT is charged on certain fields in the North Sea at the rate of 50% of net operating income, after certain deductions including abandonment expenditures. Taxes other than income taxes increased from the comparable periods as a result of higher crude oil prices and increased production levels.

Taxable income from the conventional crude oil and natural gas business in Canada is generated by partnerships and the related income taxes will be payable in the following year. Current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary dependent upon the amount of capital expenditures incurred in Canada and the way it is deployed.

The Company is liable for the payment of Federal Large Corporations Tax ("LCT"). LCT for the six months ended decreased to $4 million from $10 million as a result of the Company being taxable and paying Federal corporate surtax. In addition, the LCT rate was reduced from 0.225% to 0.2% as part of the phased elimination of LCT over five years.

In the first half of 2004, the North America future tax liability was reduced by $66 million as a result of a reduction in the Alberta corporate income tax rate from 12.5% to 11.5%, resulting in a future income tax expense of $66 million for the six months ended June 30, 2004 and a future income tax recovery of $18 million for the three months ended March 31, 2004. The Federal Government also introduced legislation to reduce the corporate income tax rate on income from resource activities over a five-year period starting January 1, 2003, bringing the resource industry in line with the general corporate income tax rate. As part of the corporate income tax rate reduction, the legislation also provides for the elimination of the existing 25% resource allowance and the introduction of a deduction for actual provincial and other crown royalties paid. As a result of the Federal and Provincial tax rate reductions, the future income tax liability in North America was decreased by $247 million, resulting in a future income tax expense of $87 million for the six months ended June 30, 2003 and a future income tax recovery of $140 million for the three months ended June 30, 2003.

The following table shows the effect of non-recurring benefits:

TAXES ($ millions, except income tax rates)

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Income tax as reported					
Current income tax	**$ 64**	$ 66	$ 19	**$ 130**	$ 58
Future income tax expense (recovery)	**84**	(18)	(140)	**66**	87
	148	48	(121)	**196**	145
Alberta corporate tax rate reduction	**-**	66	31	**66**	31
Federal corporate tax rate reduction	**-**	-	216	**-**	216
Total	**$ 148**	$ 114	$ 126	**$ 262**	$ 392
Effective income tax rate	**36.0%**	37.1%	31.9%	**36.5%**	36.1%

CAPITAL EXPENDITURES ($ millions)

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Business Combination	**$ -**	$ 471	$ –	**$ 471**	$ –
Expenditures on property, plant and equipment					
Net property acquisitions	**$ 277**	$ 36	$ 23	**$ 313**	$ 201
Land acquisition and retention	**39**	31	36	**70**	57
Seismic evaluations	**11**	32	21	**43**	40
Well drilling, completion and equipping	**231**	583	190	**814**	586
Pipeline and production facilities	**166**	280	107	**446**	256
Total net reserve replacement expenditures	**$ 724**	$ 962	$ 377	**$ 1,686**	$ 1,140
Horizon Oil Sands Project	**103**	46	27	**149**	68
Midstream	**3**	-	1	**3**	4
Abandonments	**6**	7	3	**13**	6
Head office	**8**	7	2	**15**	5
Total net capital expenditures	**$ 844**	$ 1,022	$ 410	**$ 1,866**	$ 1,223
By segment					
North America	**$ 578**	$ 826	$ 288	**$ 1,404**	$ 931
North Sea	**75**	76	43	**151**	133
Offshore West Africa	**71**	60	46	**131**	76
Horizon Oil Sands Project	**103**	46	27	**149**	68
Midstream	**3**	-	1	**3**	4
Abandonments	**6**	7	3	**13**	6
Head office	**8**	7	2	**15**	5
Total	**$ 844**	$ 1,022	$ 410	**$ 1,866**	$ 1,223

The Company's strategy is focused on building a diversified asset base that is balanced between various products. The capital expenditures program continues to reflect this strategy.

During the first half of 2004, capital expenditures were $1,866 million, excluding the acquisition of Petrovera, compared to $1,223 million in the first half of 2003. The Company continues to make significant progress on its larger, future-growth projects while maintaining its focus on existing assets. The Company drilled a total of 971 net wells consisting of 444 natural gas wells, 185 crude oil wells, 270 stratigraphic test and service wells, and 72 wells that were dry and abandoned compared to 973 net wells in the first half of 2003. The Company achieved an overall success rate of 90%, excluding stratigraphic test and service wells. These excellent results reflect the disciplined approach that the Company takes in its exploitation and development programs and the strength of its asset base.

North America accounted for 85% of the total capital expenditures in the first half of 2004 compared to 83% in the comparable period in the prior year.

Capital expenditures in the second quarter of 2004 were $844 million compared to $410 million in the comparable period in 2003. In the second quarter the Company drilled 132 net wells, including 2 stratigraphic test and service wells. The majority of the Company's natural gas regions are winter-access only, which results in the majority of the Company's natural gas drilling being concentrated in the winter months and the reduction of natural gas drilling in the second quarter.

North America

During the second quarter, the Company drilled 87 net wells targeting natural gas, including 2 wells in Northeast British Columbia and 13 wells in Northwest Alberta. Northeast British Columbia and Northwest Alberta core regions are the Company's high potential natural gas growth areas. The Company also drilled 43 net wells targeting crude oil and NGLs during the second quarter 2004. These wells were concentrated in the Company's crude oil region of North Alberta where 11 primary heavy crude oil and 14 Pelican Lake wells were drilled. Also included in this figure were 12 high-pressure horizontal thermal crude oil wells that were drilled and completed at Primrose as part of the 2004 development strategy of the area. The Company also completed the acquisition of certain resource properties located in Northeast British Columbia and Northwest Alberta for $280 million in the second quarter. These properties include a further ownership interest in the Ladyfern natural gas field. In addition, the Company acquired undeveloped acreage in the Foothills area of Alberta and British Columbia. This area is characterized by large, undeveloped pools with significant natural gas potential in deeper zones and will add a new exploration base in the Alberta Foothills. Work also continues on the Company's Pelican Lake enhanced crude oil recovery project, located in North Alberta. The waterflood project in Pelican Lake is being phased in and it is expected that approximately 20% of the Pelican Lake Field will be under waterflood by the end of 2004. It is expected that the waterflood will stabilize production. The Company is also running a field pilot of a water / emulsion flood process and expects to have the results later this year. In the Primrose area in North Alberta, the Company continues with its expansion project, drilling additional wells and converting existing wells from low-pressure to high-pressure steaming.

In the Horizon Oil Sands Project ("Horizon Project"), capital expenditures include work relating to the third front-end engineering phase, Engineering Design Specifications ("EDS"). The EDS is expected to be completed in the fall of 2004 and will provide sufficient definition for a lump-sum inquiry for the detailed Engineering, Procurement and Construction ("EPC") of the various project components. The EDS will also provide a detailed cost estimate, and provide the basis upon which management can make a final recommendation to the Board of Directors for sanction of the Horizon Project. The first half of 2004 also included the drilling of 180 stratigraphic test wells on the oil sands leases of the Horizon Project. The Company received regulatory approvals from the Alberta Energy and Utilities Board as well as the Alberta Provincial Cabinet and the Federal Cabinet.

The Cold Lake Pipeline Limited Partnership, in which the Company has a 15% working interest, will be investing $16 million in 2004 to construct new facilities to allow shipment of up to 60,000 bbl/d of Synbit product. This new blend will include condensate as well as synthetic light crude oil as a blending component to dilute the heavy, tar-like Cold Lake bitumen. The Synbit project will involve the construction of two 80,000 barrel storage tanks, pumping facilities and metering equipment on the Cold Lake system. Regulatory approvals have been obtained and construction is currently underway.

North Sea

During the second quarter of 2004, the Company completed the drilling of a Columba B Terrance well and a development well in the Lyell Field. In the Banff Field, work to convert the field to gas injection has begun. The Company continued to proceed with its planned program of infill drilling, recompletions, workovers and waterflood optimizations.

Offshore West Africa

Offshore West Africa capital expenditures include the ongoing development of the Baobab Field where development drilling is ongoing. In addition, the Floating Production, Storage and Offtake Vessel ("FPSO") is under construction and sub-sea equipment is being manufactured. Development also continued on the West Espoir Field where eight producing wells and three injection wells will be drilled from the wellhead tower and tied back to the existing East Espoir FPSO. In Angola, the Company continued to integrate the well data from the Zenza well into its Geological and Geophysical models and will likely drill the second exploration well in 2005.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)

	Jun 30 2004	Mar 31 2004	Dec 31 2003(1)	Jun 30 2003(1)
Working capital deficit(2)	**$ 444**	$ 923	$ 505	$ 459
Long-term debt	**$ 3,609**	$ 3,061	$ 2,645	$ 2,904
Shareholders' equity				
Preferred securities	**$ 107**	$ 104	$ 103	$ 108
Share capital	**2,393**	2,380	2,353	2,360
Retained earnings	**4,090**	3,881	3,650	3,294
Foreign currency translation adjustment	**-**	1	3	10
Total	**$ 6,590**	$ 6,366	$ 6,109	$ 5,772
Debt to cash flow(2) (3)	**1.1x**	1.0x	0.9x	1.0x
Debt to EBITDA(2) (3)	**1.0x**	0.9x	0.8x	0.9x
Debt to book capitalization(1) (2)	**35.4%**	33.7%	31.6%	35.0%
Debt to market capitalization(2)	**25.0%**	24.7%	24.2%	29.7%
After tax return on average common shareholders' equity(1) (2) (3)	**16.0%**	21.4%	25.6%	26.7%
After tax return on average capital employed(1) (2) (3)	**11.5%**	14.6%	16.7%	16.5%

(1) *Restated for change in accounting policy (see consolidated financial statements note 2).*

(2) *Includes current portion of long-term debt.*

(3) *Based on trailing 12-month activity.*

At June 30, 2004, the working capital deficit amounted to $444 million and includes the current portion of other long-term liabilities of $329 million consisting of stock based compensation of $172 million and the mark to market valuation of certain Risk Management financial derivative instruments of $157 million. The settlement of the stock-based compensation liability is dependant upon the surrender of vested stock options for cash settlement by employees and the value of the Company's share price at the time of exercise. The settlement of the Risk Management financial derivative instruments is primarily dependant upon the underlying crude oil and natural gas prices at the time of settlement of the financial derivative instrument, as compared to the value at June 30, 2004. At June 30, 2004, the Company had no current portion of long-term debt and undrawn bank lines of credit of $775 million.

The financing of the first phase of the Horizon Project development will be guided by the competing principles of retaining as much direct ownership interest as possible while maintaining current strong debt ratings and not issuing additional equity in common shares. The Company continues to investigate the use of long-term commodity hedges in order to reduce cash flow risks during the construction phase. The Company may also look to offload capital commitments through the acceptance of complementary business partners, or potentially, project joint venture partners. Recent commodity price increases have significantly strengthened the balance sheet of the Company, thereby placing it in a better position to achieve all three of its guiding principles.

Share Capital

Shareholders of the Company approved a subdivision or share split of its issued and outstanding common shares on a two-for-one basis at the Company's Annual and Special Meeting held on May 6, 2004. As at June 30, 2004, there were 267,910,000 common shares outstanding. As at July 30, 2004, there were 267,938,000 common shares outstanding.

In January 2004, the Company renewed its Normal Course Issuer Bid allowing it to purchase up to 13,380,770 common shares or 5% of the Company's outstanding common shares on the date of announcement, during the 12-month period beginning January 24, 2004 and ending January 23, 2005. As at June 30, 2004, the Company had purchased 800,000 common shares for a total cost $30 million at an average purchase price of $37.60 per common share.

In February 2004, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.40 per common share in 2004, up from the previous level of $0.30 per common share. The 33% increase recognized the stability of the Company's increased cash flow and provided a further return to shareholders. This is the fourth consecutive year in which the Company has paid dividends and the third consecutive year of an increase in the distribution paid to its shareholders.

CHANGE IN ACCOUNTING POLICIES

Asset Retirement Obligations

On January 1, 2004, the Company retroactively adopted the Canadian Institute of Chartered Accountants' ("CICA") new Handbook Section 3110, "Asset Retirement Obligations". The Section requires the recognition of the fair value of the asset retirement obligation for related long-term assets as a liability. Retirement costs equal to the discounted retirement obligation are capitalized as part of the cost of the associated capital asset and amortized to expense through depletion over the life of the asset. In subsequent periods, the asset retirement obligation is adjusted for the passage of time and for any changes in the amount or timing of the underlying future cash flows. This new standard was adopted retroactively and prior period comparative balances have been restated. The effects on the Company's consolidated financial statements resulting from the adoption of the standard are discussed in notes 2 and 5 of the consolidated financial statements.

Risk Management Activities

On January 1, 2004, the Company prospectively adopted the CICA's Accounting Guideline 13, "Hedging Relationships" and EIC 128, "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments". Guideline 13 and EIC 128 require that financial instruments that are not designated as hedges be recorded on the Company's consolidated balance sheet at fair value on the date thereof, with subsequent changes in fair value recorded in earnings on a quarterly reporting basis. Adoption of Guideline 13 and EIC 128 resulted in the Company recognizing an unrealized mark-to-market loss of $172 million ($115 million, net of tax) in the six months ended June 30, 2004 relating to its financial instruments. The unrealized loss assumes that all unsettled derivative financial instruments were settled on June 30, 2004 and were valued based on market conditions existing at that point in time. As a result of the adoption of this standard, the Company expects the volatility in its net earnings to increase, which is directly attributable to the corresponding volatility in crude oil and natural gas prices and the unsettled derivative financial instruments. The effects on the Company's consolidated financial statements are discussed later in the MD&A and in notes 2 and 5 of the consolidated financial statements.

SUBSEQUENT EVENT

Subsequent to June 30, 2004, the Company entered into binding agreements to acquire certain light crude oil producing properties in the Central North Sea. The acquired properties comprise operated interest in T-Block (Tiffany, Toni and Thelma fields) and B-Block (Balmoral, Stirling and Glamis fields), together with associated production facilities and adjacent exploration acreage. The Company equity interests in the producing fields acquired are:

T-Block	Tiffany, Toni and Thelma	88.74%
B-Block	Balmoral	70.20%
	Glamis	75.29%
	Stirling	68.68%

SENSITIVITY ANALYSIS[1]

The following table is indicative of the annualized sensitivities of cash flow and net earnings from changes in certain key variables. The analysis is based on business conditions and production volumes during the second quarter of 2004. 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[2] ($ millions)	Cash flow from operations[2] (per common share, basic)	Net earnings[2] ($ millions)	Net earnings[2] (per common share, basic)
Price changes				
Crude Oil – WTI US$1.00/bbl[3]				
Excluding financial derivatives	$ 101	$ 0.38	$ 71	$ 0.27
Including financial derivatives	$ 65	$ 0.24	$ 46	$ 0.17
Natural gas – AECO C$0.10/mcf[3]				
Excluding financial derivatives	$ 35	$ 0.13	$ 22	$ 0.08
Including financial derivatives	$ 34-35	$ 0.13	$ 20-22	$ 0.08
Volume changes				
Crude Oil – 10,000 bbl/d	$ 73	$ 0.27	$ 36	$ 0.13
Natural gas – 10 mmcf/d	$ 17	$ 0.06	$ 7	$ 0.02
Foreign currency rate change				
$0.01 change in C$ in relation to US$[3]				
Excluding financial derivatives	$ 65	$ 0.24	$ 22	$ 0.08
Including financial derivatives	$ 61-65	$ 0.23-0.24	$ 20-22	$ 0.07-0.08
Interest rate change - 1%	$ 16	$ 0.06	$ 16	$ 0.06

(1) *The sensitivities are calculated based on 2004 second quarter results excluding mark-to-market on risk management activities.*

(2) *Attributable to common shareholders.*

(3) *For details of financial derivatives in place, see the consolidated financial statement note 11.*

OTHER OPERATING HIGHLIGHTS

NETBACK ANALYSIS
($/boe, except daily production)

	Three Months Ended			Six Months Ended	
	Jun 30 2004	Mar 31 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Daily production (boe/d)	**517,343**	476,944	461,455	**497,143**	458,719
Sales price[1]	**$ 38.20**	$ 35.88	$ 33.91	**$ 37.09**	$ 38.32
Royalties	**5.55**	5.03	5.32	**5.30**	6.13
Production expense[2]	**7.12**	7.02	7.34	**7.08**	7.31
Netback	**25.53**	23.83	21.25	**24.71**	24.88
Midstream contribution[2]	**(0.24)**	(0.27)	(0.25)	**(0.26)**	(0.29)
Administration	**0.58**	0.54	0.56	**0.56**	0.50
Share bonus plan	**0.05**	0.11	-	**0.08**	-
Interest	**0.98**	0.98	1.19	**0.98**	1.29
Risk management activities loss – realized	**2.12**	0.64	0.38	**1.41**	1.85
Foreign exchange (gain) loss – realized	**(0.22)**	(0.09)	0.23	**(0.16)**	0.13
Taxes other than income tax (current)	**1.08**	0.82	0.48	**0.96**	0.55
Current income tax (North America)	**0.95**	0.86	0.28	**0.91**	0.33
Current income tax (Large corporations tax)	**-**	0.08	0.12	**0.04**	0.13
Current income tax (North Sea)	**0.32**	0.52	0.02	**0.42**	0.19
Current income tax (Offshore West Africa)	**0.08**	0.07	0.04	**0.08**	0.05
Cash flow	**$ 19.83**	$ 19.57	$ 18.20	**$ 19.69**	$ 20.15

(1) *Including transportation costs.*

(2) *Excluding intersegment eliminations.*

FINANCIAL STATEMENTS

Consolidated balance sheets

(millions of Canadian dollars, unaudited)		**Jun 30 2004**		Dec 31 2003(1)
ASSETS				
Current assets				
Cash	**$**	**16**	$	104
Accounts receivable and other		**1,039**		751
		1,055		855
Property, plant and equipment (net)		**15,402**		13,714
Deferred charges		**75**		74
	$	**16,532**	$	14,643
LIABILITIES				
Current liabilities				
Accounts payable	**$**	**531**	$	464
Accrued liabilities		**639**		582
Current portion of long-term debt (note 4)		**-**		184
Current portion of other long-term liabilities (note 5)		**329**		130
		1,499		1,360
Long-term debt (note 4)		**3,609**		2,645
Other long-term liabilities (note 5)		**973**		938
Future income tax (note 6)		**3,861**		3,591
		9,942		8,534
SHAREHOLDERS' EQUITY				
Preferred securities		**107**		103
Share capital (note 7)		**2,393**		2,353
Retained earnings		**4,090**		3,650
Foreign currency translation adjustment (note 8)		**-**		3
		6,590		6,109
	$	**16,532**	$	14,643

(1) *Restated (note 2).*

Consolidated statements of earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended Jun 30 2004	Three Months Ended Jun 30 2003(1)	Six Months Ended Jun 30 2004	Six Months Ended Jun 30 2003(1)
Revenue	**$ 1,865**	$ 1,502	**$ 3,503**	$ 3,342
Less: royalties	**(262)**	(223)	**(480)**	(509)
Revenue, net of royalties	**1,603**	1,279	**3,023**	2,833
Expenses				
Production	**339**	311	**647**	614
Transportation	**50**	65	**116**	130
Depletion, depreciation and amortization	**426**	370	**815**	731
Asset retirement obligation accretion (note 5)	**10**	15	**21**	30
Administration	**27**	23	**50**	41
Stock-based compensation (note 5)	**52**	105	**113**	105
Interest	**46**	50	**89**	107
Risk management activities	**170**	16	**300**	154
Foreign exchange loss (gain)	**23**	(99)	**65**	(217)
	1,143	856	**2,216**	1,695
Earnings before taxes	**460**	423	**807**	1,138
Taxes other than income tax	**49**	24	**88**	52
Current income tax (note 6)	**64**	19	**130**	58
Future income tax expense (recovery) (note 6)	**84**	(140)	**66**	87
Net earnings	**263**	520	**523**	941
Dividend on preferred securities, net of tax	**(2)**	(2)	**(3)**	(3)
Revaluation of preferred securities, net of tax	**(2)**	7	**(3)**	14
Net earnings attributable to common shareholders	**$ 259**	$ 525	**$ 517**	$ 952
Net earnings attributable to common shareholders per common share (note 9)				
Basic	**$ 0.97**	$ 1.96	**$ 1.93**	$ 3.56
Diluted	**$ 0.97**	$ 1.89	**$ 1.93**	$ 3.43

(1) *Restated (note 2).*

Consolidated statements of retained earnings

(millions of Canadian dollars, unaudited)	Six Months Ended **Jun 30 2004**	Jun 30 2003(1)
Balance – beginning of period as previously reported	**$ 3,644**	$ 2,414
Change in accounting policy (note 2)	**6**	10
Balance – beginning of period as restated	**3,650**	2,424
Net earnings	**523**	941
Dividend on common shares (note 7)	**(54)**	(40)
Purchase of common shares (note 7)	**(23)**	(42)
Dividend on preferred securities, net of tax	**(3)**	(3)
Revaluation of preferred securities, net of tax	**(3)**	14
Balance – end of period	**$ 4,090**	$ 3,294

(1) *Restated (note 2).*

Consolidated statements of cash flows

(millions of Canadian dollars, unaudited)	Three Months Ended Jun 30 2004	Three Months Ended Jun 30 2003(1)	Six Months Ended Jun 30 2004	Six Months Ended Jun 30 2003(1)
Operating activities				
Net earnings	**$ 263**	$ 520	**$ 523**	$ 941
Non-cash items				
Depletion, depreciation and amortization	**426**	370	**815**	731
Asset retirement obligation accretion	**10**	15	**21**	30
Stock-based compensation	**50**	105	**106**	105
Deferred petroleum revenue tax (recovery)	**(3)**	4	**1**	7
Unrealized risk management activities	**70**	-	**172**	-
Future income tax (recovery)	**84**	(140)	**66**	87
Unrealized foreign exchange loss (gain)	**33**	(109)	**79**	(228)
Deferred charges	**5**	(3)	**(1)**	2
Abandonment expenditures	**(6)**	(3)	**(13)**	(6)
Net change in non-cash working capital	**(9)**	(98)	**(161)**	(180)
	923	661	**1,608**	1,489
Financing activities				
Issue (repayment) of bank credit facilities	**498**	(129)	**881**	(501)
Repayment of medium-term notes	**(125)**	-	**(125)**	-
Repayment of senior unsecured notes	**(54)**	(71)	**(54)**	(71)
Repayment of obligations under capital leases	**(1)**	(1)	**(7)**	(6)
Issue of common shares	**8**	45	**20**	79
Purchase of common shares	**(30)**	(33)	**(30)**	(65)
Dividend on common shares	**(27)**	(20)	**(47)**	(37)
Dividend on preferred securities	**(3)**	(3)	**(5)**	(5)
Net change in non-cash working capital	**5**	(10)	**(4)**	(8)
	271	(222)	**629**	(614)
Investing activities				
Business combination, net of cash acquired (note 3)	**-**	-	**(444)**	-
Expenditures on property, plant and equipment	**(840)**	(418)	**(1,857)**	(1,235)
Net proceeds on sale of property, plant and equipment	**2**	11	**4**	18
Net expenditures on property, plant and equipment	**(838)**	(407)	**(2,297)**	(1,217)
Net change in non-cash working capital	**(366)**	(31)	**(28)**	330
	(1,204)	(438)	**(2,325)**	(887)
(Decrease) increase in cash	**(10)**	1	**(88)**	(12)
Cash – beginning of period	**26**	17	**104**	30
Cash – end of period	**$ 16**	$ 18	**$ 16**	$ 18

(1) *Restated (note 2).*

Supplemental disclosure of cash flow information (note 10)

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, 2003, except as described in note 2. The interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2003.

Comparative figures

Certain figures provided for prior years have been reclassified to conform to the presentation adopted in 2004.

2. CHANGES IN ACCOUNTING POLICIES

Asset retirement obligation

Effective January 1, 2004, the Company retroactively adopted the Canadian Institute of Chartered Accountants' ("CICA") new Handbook Section 3110, "Asset Retirement Obligations". The Section requires the recognition of the fair value of the asset retirement obligation for related long-term assets as a liability. Retirement costs equal to the discounted retirement obligation are capitalized as part of the cost of the associated capital asset and amortized to expense through depletion over the life of the asset. In subsequent periods, the asset retirement obligation is adjusted for the passage of time and any changes in the amount or timing of the underlying future cash flows. Previously, future site restoration costs were accrued over the life of the Company's proved reserves. This new standard was adopted retroactively and prior period comparative balances have been restated. Adoption of the standard had the following effects on the Company's consolidated balance sheet as at December 31, 2003:

		Dec 31, 2003
Increase property, plant and equipment	$	445
Decrease future site restoration liability	$	(447)
Increase asset retirement obligation	$	897
Increase future income tax liability	$	3
Decrease foreign currency translation adjustment	$	(14)
Increase retained earnings	$	6

Adoption of the standard had the following effects on the Company's consolidated statements of earnings and retained earnings:

	Six Months Ended			
		Jun 30 2004		Jun 30 2003
Increase opening retained earnings	**$**	**6**	$	10
Decrease depletion, depreciation and amortization	**$**	**(61)**	$	(28)
Increase asset retirement obligation accretion	**$**	**21**	$	30
Increase (decrease) future income tax expense	**$**	**16**	$	(1)

Risk Management

Effective January 1, 2004, the Company prospectively adopted the CICA's Accounting Guideline 13, "Hedging Relationships" and EIC 128, "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments". Guideline 13 addresses the types of items that qualify for hedge accounting, the formal documentation required to enable the use of hedge accounting, and the requirement to evaluate hedges for effectiveness. EIC 128 requires that financial instruments that are not designated as hedges be recorded at fair value on the Company's consolidated balance sheet, with subsequent changes in fair value recorded in earnings. The Company has designated certain of its derivative financial instruments (note 11) as hedges, including certain crude oil puts, the currency swap on the US$125 million senior unsecured note, and the interest rate swap on the US$350 million note due October 2012. Adoption of Guideline 13 and EIC 128 had the following effects on the Company's consolidated balance sheet as at January 1, 2004:

		Jan 1, 2004
Increase financial instruments asset	$	40
Increase deferred revenue	$	40

The deferred revenue will be amortized to earnings over the term of the underlying contracts.

3. ACQUISITION OF PETROVERA PARTNERSHIP

In February 2004, the Company acquired certain resource properties in its North Alberta core region, collectively known as the Petrovera Partnership ("Petrovera"), for $471 million.

The acquisition was accounted for based on the purchase method. Results from Petrovera are consolidated with the results of the Company effective from the date of acquisition. The preliminary allocation of the purchase price to assets acquired and liabilities assumed based on their fair values is set out in the following table:

		Feb 2004
Purchase price:		
Cash consideration	$	467
Cash acquired		(23)
Non-cash working capital deficit assumed		27
Total purchase price	$	471
Net assets acquired:		
Property, plant and equipment	$	643
Future income tax liability		(129)
Asset retirement obligation		(43)
Total net assets acquired	$	471

The purchase price allocation is based on preliminary estimates of the fair values of the assets acquired, the liabilities assumed and the costs to complete the acquisition. The preliminary allocation is subject to change as the actual amounts are determined.

4. LONG-TERM DEBT

	Jun 30 2004	Dec 31 2003
Bank credit facilities		
Bankers' acceptances	**$ 425**	$ -
US dollar bankers' acceptances (2004 – US$545 million, 2003 – US$207 million)	**730**	268
Medium-term notes	**125**	250
Senior unsecured notes (2004 – US$218 million, 2003 – US$258 million)	**318**	366
US dollar debt securities (2004 – US$1,500 million, 2003 – US$1,500 million)	**2,011**	1,938
Obligations under capital leases	**-**	7
	3,609	2,829
Less: current portion of long-term debt	**-**	184
	$ 3,609	$ 2,645

Bank credit facilities

At June 30, 2004, the Company had unsecured bank credit facilities of $1,925 million comprised of a $100 million operating demand facility and a revolving credit and term loan facility of $1,825 million.

In addition to the outstanding debt, letters of credit aggregating $22 million have been issued.

Medium-term notes

In May 2004, the Company repaid the $125 million 6.85% unsecured debentures due May 28, 2004.

Senior unsecured notes

In May 2004, the Company repaid the US$40 million 6.42% senior unsecured notes due May 27, 2004.

5. OTHER LONG-TERM LIABILITIES

	Jun 30 2004	Dec 31 2003
Asset retirement obligation	**$ 919**	$ 897
Stock-based compensation	**211**	171
Risk management	**127**	-
Deferred revenue	**45**	-
	1,302	1,068
Less: current portion	**329**	130
	$ 973	$ 938

Asset retirement obligation

At June 30, 2004, the Company's total estimated undiscounted costs to settle its asset retirement obligation with respect to crude oil and natural gas properties and facilities was $2,592 million (December 31, 2003 – $2,281 million). These costs will be incurred over several years and have been discounted using a credit-adjusted risk free rate of 6.7%. A reconciliation of the discounted asset retirement obligation is as follows:

	Six Months Ended Jun 30, 2004	Year Ended Dec 31, 2003[(1)]
Asset retirement obligation		
Balance – beginning of period	**$ 897**	$ 867
Liabilities incurred	**51**	117
Liabilities settled	**(13)**	(40)
Asset retirement obligation accretion	**21**	62
Revision of estimates	**(54)**	(6)
Foreign exchange	**17**	(103)
Balance – end of period	**$ 919**	$ 897

(1) *Effective January 1, 2004, the Company retroactively adopted CICA Handbook section 3110, "Asset Retirement Obligations" (note 2). The prior period balance of other long-term liabilities has been restated.*

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

Stock-based compensation

The Company's Stock Option Plan ("Option Plan") results in the recognition of a liability for the expected cash settlements under the Option Plan. The current portion represents the amount of the liability that could be realized within the next 12 month period if all currently vested options and all options vesting during that period are surrendered for cash settlement.

	Six Months Ended Jun 30, 2004	Year Ended Dec 31, 2003
Stock-based compensation		
Balance – beginning of period	**$ 171**	**$** -
Stock-based compensation provision	**113**	200
Current period expense relating to share bonus plan	**(7)**	-
Current period payment for options surrendered	**(45)**	(31)
Transferred to common shares	**(27)**	(8)
Capitalized with respect to Horizon Project	**6**	10
Balance – end of period	**211**	171
Less: current portion	**172**	130
	$ 39	**$** 41

Risk Management

On January 1, 2004, the fair values of all outstanding financial instruments that were not designated as hedges for accounting purposes were recorded on the consolidated balance sheet, with an offsetting net deferred revenue amount (note 2). Subsequent changes in fair value are recognized on the consolidated balance sheet and in net earnings. The estimated fair value for all financial instruments is based on third party indications. The following table reconciles the change in derivative financial instruments:

Liability (asset)	Deferred revenue	Risk management Mark-to-market
Fair value of financial instruments – beginning of period	**$ 40**	**$ (40)**
Change in fair value of financial instruments	**-**	**167**
Amortization of deferred revenue	**5**	**-**
Fair value of financial instruments – end of period	**45**	**127**
Less: current portion	**29**	**128**
	$ 16	**$ (1)**

6. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Six Months Ended	
	Jun 30 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Current income tax expense				
Current income tax – North America	**$ 45**	$ 12	**$ 82**	$ 28
Large corporations tax – North America	**1**	4	**4**	10
Current income tax – North Sea	**14**	1	**37**	16
Current income tax – Offshore West Africa	**4**	2	**7**	4
	64	19	**130**	58
Future income tax expense (recovery)	**84**	(140)	**66**	87
Income taxes	**$ 148**	$ (121)	**$ 196**	$ 145

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. Current income tax will vary and is dependant upon the amount of capital expenditures incurred in Canada and the way it is deployed.

In March 2004, the Government of Alberta introduced legislation to reduce its corporate income tax rate by 1% effective April 1, 2004, and accordingly, the Company's future income tax liability was reduced by $66 million in the first quarter. The legislation received royal assent in May 2004.

In the second quarter of 2003, the Alberta government introduced legislation to reduce the provincial corporate income tax rate by 0.5% and the Federal government introduced legislation to phase in over five years a reduction in corporate income tax rates, the elimination of the deduction for resource allowance, and the introduction of a deduction for crown charges. The Alberta and Federal corporate income tax changes resulted in a reduction of the future income tax liability of $31 million and $247 million respectively in the second quarter of 2003.

7. SHARE CAPITAL

Issued

	Six Months Ended June 30, 2004		
Common shares	**Number of shares** (thousands)[1]		**Amount**
Balance – beginning of period	**267,463**	**$**	**2,353**
Issued upon exercise of stock options	**1,247**		**20**
Previously recognized liability on stock options exercised for common shares	**-**		**27**
Purchase of shares under Normal Course Issuer Bid	**(800)**		**(7)**
Balance – end of period	**267,910**	**$**	**2,393**

(1) Restated to reflect two-for-one share split in May 2004.

Share split

The Company's shareholders approved a subdivision or share split of its issued and outstanding common shares on a two-for-one basis at the Company's Annual and Special Meeting held on May 6, 2004. All common share and per common share amounts have been restated to retroactively reflect the share split.

Normal course issuer bid

On January 22, 2004, 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 13,380,770 common shares or 5% of the outstanding common shares of the Company on the date of announcement during the 12-month period beginning January 24, 2004 and ending January 23, 2005. As at June 30, 2004, the Company had purchased 800,000 common shares for a total cost of $30 million. The excess cost over the book value of the shares purchased was applied to retained earnings.

Dividend policy

On February 19, 2004, the Board of Directors set the regular quarterly dividend at $0.10 per common share (2003 - $0.075 per common share). The Company pays regular quarterly dividends in January, April, July, and October of each year.

Stock options

	Six Months Ended June 30, 2004	
	Stock options (thousands)(1)	**Weighted average exercise price**(1)
Outstanding – beginning of period	**17,789**	**$ 19.72**
Granted	**4,077**	**$ 34.14**
Exercised for common shares	**(1,247)**	**$ 15.93**
Surrendered for cash settlement	**(2,468)**	**$ 18.03**
Forfeited	**(598)**	**$ 27.71**
Outstanding – end of period	**17,553**	**$ 23.30**
Exercisable – end of period	**3,805**	**$ 18.56**

(1) Restated to reflect two-for-one share split in May 2004.

8. FOREIGN CURRENCY TRANSLATION ADJUSTMENT

The foreign currency translation adjustment represents the unrealized gain (loss) on the Company's net investment in self-sustaining foreign operations. 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, gains and losses on this debt are included in the foreign currency translation adjustment.

	Jun 30 2004
Balance – beginning of period as previously reported	**$ 17**
Change in accounting policy (note 2)	**(14)**
Balance – beginning of period as restated	**3**
Unrealized loss on translation of net investment	**14**
Hedge of net investment with US dollar denominated debt (net of tax)	**(17)**
Balance – end of period	**$ -**

9. NET EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS PER COMMON SHARE

	Three Months Ended		Six Months Ended	
	Jun 30 2004(1)	Jun 30 2003(1)	**Jun 30 2004(1)**	Jun 30 2003(1)
Weighted average common shares outstanding (thousands)				
Basic	**268,421**	268,410	**268,063**	268,242
Effect of dilutive stock options(2)	**-**	1,992	**-**	2,060
Assumed settlement of preferred securities with common shares(3)	**-**	4,196	**-**	4,340
Diluted	**268,421**	274,598	**268,063**	274,642
Net earnings attributable to common shareholders	**$ 259**	$ 525	**$ 517**	$ 952
Dividend on preferred securities, net of tax(3)	**-**	2	**-**	3
Revaluation of preferred securities, net of tax(3)	**-**	(7)	**-**	(14)
Diluted net earnings attributable to common shareholders	**$ 259**	$ 520	**$ 517**	$ 941
Net earnings attributable to common shareholders per common share				
Basic	**$ 0.97**	$ 1.96	**$ 1.93**	$ 3.56
Diluted	**$ 0.97**	$ 1.89	**$ 1.93**	$ 3.43

(1) Restated to reflect two-for-one share split in May 2004.

(2) As a result of the modification of the Option Plan in June 2003, which resulted in the recognition of a liability and expense for all outstanding stock options, the potential common shares associated with the stock options are not included in diluted earnings per share effective from the date of the modification.

(3) Preferred securities are anti-dilutive for the three months and six months ended June 30, 2004.

10. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	Three Months Ended		Six Months Ended	
	Jun 30 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Interest paid	**$ 47**	$ 60	**$ 96**	$ 102
Taxes paid				
Taxes other than income tax	**$ 27**	$ 3	**$ 71**	$ (11)
Current income tax	**$ 40**	$ 5	**$ 63**	$ 12

11. FINANCIAL INSTRUMENTS

The Company uses certain derivative financial instruments to manage its commodity prices, 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 Company has the following financial derivatives outstanding as at July 30, 2004, which includes all transactions outstanding at June 30, 2004:

	Remaining Term	Volume	Average Price	Index
Oil				
Brent differential swaps	Jul 2004 – Dec 2004	40,000 bbl/d	US$1.22	Dated Brent/WTI
Oil price collars	Jul 2004 – Sep 2004	120,000 bbl/d	US$25.63 – US$30.40	WTI
	Oct 2004 – Dec 2004	120,000 bbl/d	US$26.25 – US$33.34	WTI
	Jan 2005 – Mar 2005	50,000 bbl/d	US$27.00 – US$34.36	WTI
	Apr 2005 – Jun 2005	30,000 bbl/d	US$29.00 – US$41.70	WTI
Oil puts	Jul 2004 – Sep 2004	20,000 bbl/d	US$29.00	WTI
	Oct 2004 – Dec 2004	20,000 bbl/d	US$27.00	WTI
	Jan 2005 – Mar 2005	90,000 bbl/d	US$29.00	WTI
	Apr 2005 – Jun 2005	80,000 bbl/d	US$29.00	WTI

	Remaining Term	Volume	Average Price	Index
Natural gas				
AECO collars	Jul 2004 – Oct 2004	400,000 GJ/d	C$5.00 – C$8.75	AECO

	Remaining Term	Amount ($ millions)	Average Exchange Rate (US$/C$)
Foreign currency			
Currency collars	Jul 2004 – Jul 2004	US$20/month	1.51 – 1.59
	Jul 2004 – Aug 2004	US$5/month	1.52 – 1.59
	Jul 2004 – Dec 2004	US$3/month	1.45 – 1.54
	Jul 2004 – Aug 2005	US$10/month	1.37 – 1.49

	Remaining Term	Amount ($ millions)	Exchange Rate (US$/C$)	Interest Rate (US$)	Interest Rate (C$)
Currency swap	Jul 2004 – Dec 2005	US$125	1.55	7.69%	7.30%

	Remaining Term			Amount ($ millions)	Fixed Rate	Floating Rate
Interest rate						
Swaps – fixed to floating	Jul 2004	–	Jul 2004	US$200	6.70%	LIBOR + 2.09%
	Jul 2004	–	Jul 2006	US$200	6.70%	LIBOR + 1.65%
	Jul 2004	–	Jan 2005	US$200	7.20%	LIBOR + 3.00%
	Jul 2004	–	Jan 2007	US$200	7.20%	LIBOR + 2.23%
	Jul 2004	–	Oct 2012	US$350	5.45%	LIBOR + 0.81%
Swaps – floating to fixed	Jul 2004	–	Mar 2007	C$12	7.36%	CDOR

12. SEGMENTED INFORMATION

	Three Months Ended		Six Months Ended	
	Jun 30 2004	Jun 30 2003	**Jun 30 2004**	Jun 30 2003
Revenue				
North America	**$ 1,510**	$ 1,261	**$ 2,828**	$ 2,789
North Sea	**293**	202	**556**	478
Offshore West Africa	**56**	33	**106**	60
Midstream	**17**	14	**33**	32
Intersegment elimination	**(11)**	(8)	**(20)**	(17)
	$ 1,865	$ 1,502	**$ 3,503**	$ 3,342
Net Earnings				
North America	**$ 185**	$ 481	**$ 400**	$ 841
North Sea	**52**	18	**78**	69
Offshore West Africa	**20**	13	**33**	17
Midstream	**6**	8	**12**	14
	263	520	**523**	941
Dividend on preferred securities, net of tax	**(2)**	(2)	**(3)**	(3)
Revaluation of preferred securities, net of tax	**(2)**	7	**(3)**	14
Net Earnings Attributable to Common Shareholders	**$ 259**	$ 525	**$ 517**	$ 952
Additions to Property, Plant and Equipment				
North America – business combination	**$ -**	$ -	**$ 645**	$ -
North America – crude oil and natural gas	**576**	288	**1,402**	931
North Sea	**75**	41	**151**	148
Offshore West Africa	**71**	46	**131**	76
Horizon Oil Sands Project	**103**	27	**149**	68
Midstream	**3**	1	**3**	4
Abandonments	**6**	3	**13**	6
Head office	**8**	2	**15**	5
	$ 842	$ 408	**$ 2,509**	$ 1,238

	Property, Plant and Equipment		Total Assets	
	Jun 30 2004	Dec 31 2003	**Jun 30 2004**	Dec 31 2003
Segmented Assets				
North America	**$ 12,380**	$ 10,990	**$ 13,262**	$ 11,731
North Sea	**1,476**	1,437	**1,652**	1,562
Offshore West Africa	**768**	667	**801**	703
Horizon Oil Sands Project	**530**	381	**530**	381
Midstream	**199**	200	**238**	227
Head office	**49**	39	**49**	39
	$ 15,402	$ 13,714	**$ 16,532**	$ 14,643

13. SUBSEQUENT EVENT

Subsequent to June 30, 2004, the Company entered into binding agreements to acquire certain light crude oil producing properties in the Central North Sea. The acquired properties comprise operated interest in T-Block (Tiffany, Toni and Thelma fields) and B-Block (Balmoral, Stirling and Glamis fields), together with associated production facilities and adjacent exploration acreage. The Company equity interests in the producing fields acquired are:

T-Block	Tiffany, Toni and Thelma	88.74%
B-Block	Balmoral	70.20%
	Glamis	75.29%
	Stirling	68.68%

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 2003. These ratios are based on the Company's consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the 12-month period ended June 30, 2004:

Interest coverage (times)	
Net earnings	10.2x
Cash flow from operations	22.9x

(1) *Net earnings plus income taxes and interest expense; divided by interest expense.*

(2) *Cash flow from operations plus current income taxes and interest expense; divided by interest expense.*

The interest coverage ratios have been calculated without including the annual carrying charges relating to the outstanding preferred securities of the Company. If the preferred securities were classified as long-term debt, these annual carrying charges would be included in interest. If these annual carrying charges had been included in the calculations, the net earnings coverage ratio for the 12-month period ended June 30, 2004, would be 9.7x and the cash flow coverage ratio for the 12-month period ended June 30, 2004 would be 21.7x.

2004 THIRD QUARTER RESULTS

2004 third quarter results are scheduled for release on Wednesday, November 3, 2004. A conference call will be held on that day at 9:00 a.m. Mountain Standard Time, 11:00 a.m. Eastern Standard Time.

CORPORATE PROFILE

Canadian Natural is one of the largest independent crude oil and natural gas producers in the world. We achieved this status through continued application of our value creation objectives and defined growth strategy. We have a low-cost, diversified combination of assets in North America, the North Sea and Offshore West Africa, which enables us to generate significant value, even in challenging economic environments. Our balanced mix of natural gas, light oil and heavy oil production, combined with a major oil sands mining project, represents one of the strongest and most diverse asset portfolios of any energy producer in the world.

CORPORATE INFORMATION

Officers

Allan P. Markin
Chairman

N. Murray Edwards
Vice-Chairman

John G. Langille
President

Steve W. Laut
Chief Operating Officer

Réal M. Cusson
Senior Vice-President, Marketing

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

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

Tim S. McKay
Senior Vice-President, North American Operations

Douglas A. Proll
Senior Vice-President, Finance

Lyle G. Stevens
Senior Vice-President, Exploitation

J. Kevin Stromquist
Senior Vice-President, Exploration

Bruce E. McGrath
Corporate Secretary

Mary-Jo E. Case
Vice-President, Land

Wayne M. Chorney
Vice-President, Development Operations

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

Gordon M. Coveney
Vice-President, Exploration – East

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

Jerome W. Harvey
Vice-President, Commercial Operations

Terry J. Jocksch
Vice-President, Exploitation – East

Cameron S. Kramer
Vice-President, Field Operations

León Miura
Vice-President, Upgrading – Oil Sands

John S. J. Parr
Vice-President, Production – East

David A. Payne
Vice-President, Exploitation – West

William R. Peterson
Vice-President, Production – West

John C. Puckering
Vice-President, Site Development – Oil Sands

Sheldon L. Schroeder
Vice-President, Project Control – Oil Sands

Jeffrey W. Wilson
Vice-President, Exploration – West

Lynn M. Zeidler
Vice-President, Bitumen Production – Oil Sands

Stock Listing

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

*denotes trading in US funds

New York Stock Exchange
Trading Symbol – CNQ

Registrar and Transfer Agent

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
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Board of Directors

Catherine M. Best

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