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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 6-K

REPORT OF FOREIGN PRIVATE ISSUER

Pursuant to Section 13a-16 15d-16 of the
Securities Exchange Act of 1934

Press Release dated May 8, 2002 - First Quarter Results

CANADIAN NATURAL RESOURCES LIMITED
(Exact name of registrant as specified in its charter)

Canada (State or other jurisdiction of incorporation)	1-8795 (Commission File Number)	Not applicable (I.R.S. Employer Identification No.)

2500, 855 – 2nd Street S.W., Calgary, Alberta, Canada (Address of principal executive offices)	T2P 4J8 (Zip Code)

Registrant's telephone number, including area code: (403) 517-6700

Indicate by check mark whether the registrant files or will file annual reports under cover Form 20-F or Form 40-F.

Form 20-F ___ Form 40-F X

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes ___ No X

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): 82-______.

SIGNATURES

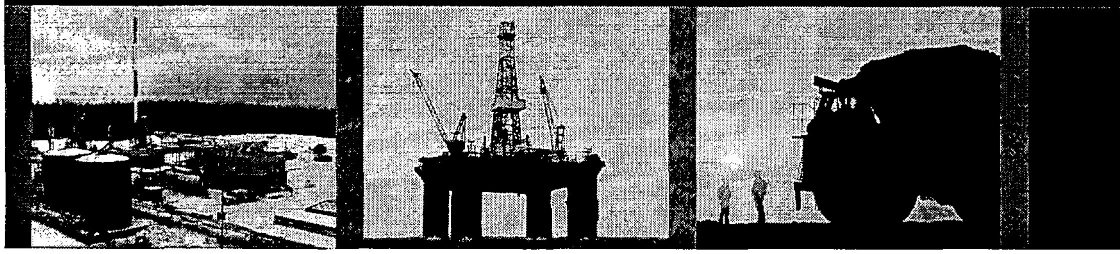
Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CANADIAN NATURAL RESOURCES LIMITED
(Registrant)

Date: May 15, 2002

By: ______________________
B. E. McGRATH
Assistant Corporate Secretary

CANADIAN NATURAL RESOURCES LIMITED



Press Release

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES
2002 FIRST QUARTER RESULTS
CALGARY, ALBERTA – May 8, 2002 – FOR IMMEDIATE RELEASE

CANADIAN NATURAL ANNOUNCES RECORD NATURAL GAS PRODUCTION AND CONTINUED STRONG CASH FLOW AND EARNINGS

In commenting on first quarter 2002 results, Canadian Natural's Chairman, Allan Markin, stated "As a result of last year's focus on natural gas exploration, Canadian Natural exits the first quarter of 2002 with natural gas production of just under 1.1 billion cubic feet per day. This makes us Canada's second largest natural gas producer. Additionally, given the current forward market outlook for natural gas pricing over the next year coupled with narrow heavy oil differentials and strong crude oil pricing, the Company is in an excellent position to obtain strong returns on each of our product offerings."

"We proactively curtailed 15,000 barrels per day of our heavy oil production commencing December 2001. With the improvement in the heavy oil pricing differential we are now bringing some of that production back into the markets and continue to prudently evaluate opportunities to expand production. We continue to monitor this marketplace and evaluate various strategies designed to increase the certainty of pricing for this commodity."

"During the first quarter, we made significant headway on our international light oil program. We commissioned our Espoir development in Côte d'Ivoire on time and on budget and drilled a second successful exploration well at Baobab, which confirms commercial viability of that prospect. Subsequent to the first quarter a well drilled on the Kossipo structure was completed and core samples identified light oil, but in non-commercial quantities, on the southern of the two main fault blocks."

"In the North Sea, we made some headway towards our goal of consolidating interests through the completion of one acquisition and a property swap. We still have a ways to go, but I view this activity as a positive step."

"On the natural gas exploration side, the five Slave Point exploration wells in the immediate Ladyfern area have resulted in one successful discovery. This discovery, together with additional seismic shot this winter, will result in at least three additional exploration wells being drilled on Ladyfern look-a-like structures in the second and third quarter."

"With respect to our Horizon Oil Sands Project, we are continuing our regulatory approval process with formal filings to the Alberta Government planned for the summer of 2002."

HIGHLIGHTS OF THE FIRST QUARTER

- Natural gas sales of 1,053 million cubic feet per day, an increase of 24% from the first quarter of last year and a 41 million cubic feet per day increase from the previous quarter. On a barrel of oil equivalent basis, natural gas represents 48% of equivalent production during the quarter.

- Oil and liquids sales of 188 thousand barrels per day. Production of primary heavy oil and thermal heavy oil remained consistent with the fourth quarter of 2001 at 25% of production on a barrel of oil equivalent basis.

- Cash flow of $359 million ($2.95 per common share) compared with $629 million ($5.15 per common share) in the first quarter of 2001 and $326 million ($2.69 per common share) in the previous quarter.

- Net earnings of $99 million ($0.81 per common share) compared with $222 million ($1.82 per common share) for the first quarter of 2001 and $53 million ($0.44 per common share) in the previous quarter.

- As a result of lower differentials for heavy oil production, the Company realized a 15% increase in the wellhead price for its oil sales over the last quarter of 2001.

- Quarterly capital expenditures of $459 million, reflecting the high activity levels associated with winter drilling areas and Offshore West Africa drilling and development.

- First production from the Espoir field in Côte d'Ivoire. This development project continues on time and on budget with gross production anticipated to reach 30,000 barrels of oil per day later this year.

- Drilled a second successful exploration well at Baobab in Côte d'Ivoire that tested in excess of 10,000 barrels of oil per day. This well confirms commercial viability of the pool, with recoverable reserves expected to exceed 150 million barrels of oil.

- Completed negotiations on two central North Sea property transactions, which results in increased ownership in the Kyle and Banff properties and the net receipt of $48 million in cash, in exchange for our interest in the Pierce field.

- Commenced injection pilot for the experimental Pelican Lake emulsion flood, which has the potential to significantly increase the recoverable oil in the pool. Canadian Natural operates its 100% owned lands which contain approximately 80% of the pool.

- Expansion of midstream assets with the first full quarter of operations of the Cold Lake Pipeline. This 15% owned pipeline transports up to 225 thousand barrels per day of heavy oil, including 50,000 barrels of the Company's production from Cold Lake, Alberta to each of Edmonton and Hardisty, Alberta.

- Drilled nine Slave Point natural gas wells including five exploration wells. One of the exploration wells was successful and has been tied into existing production facilities.

- Completed a United States debt offering for US $400 million of 30-year notes at an interest rate of 7.20%.

- Extended its Normal Course Issuer Bid for a further 12-month period through the facilities of The Toronto Stock Exchange and the New York Stock Exchange for the purchase of up to 5% of the Company's common shares outstanding (approximately 6 million shares) at the market price, if and when acquired.

- Increased the quarterly dividend by 25% to $0.125 per common share commencing with the April 1, 2002 payment.

OPERATIONS REVIEW

Production

The quarterly results show the strength of the Company's business approach to diversification among commodities produced, namely natural gas, light oil, Pelican Lake oil, primary heavy oil and thermal heavy oil.

First quarter 2002 natural gas production averaged 1,053 million cubic feet per day, an increase of 24% from the first quarter of 2001 and a 41 million cubic feet per day increase from the fourth quarter of 2001. First quarter production benefited from the March 8, 2002 commissioning of the Canadian Natural operated pipeline connecting the Ladyfern area to sales facilities in Alberta. Natural gas production accounted for 48% of the Company's production this quarter.

Production of oil and liquids in the first quarter of 2002 decreased 8% from the first quarter of last year and 5% from fourth quarter 2001 production levels, largely the result of a proactive curtailment of 15,000 barrels per day of heavy oil production. Light oil and Pelican Lake oil production accounts for 27% of the Company's total production, a 3% decrease from the same period in 2001. Light oil production reflected the commencement of production at the Espoir field in Côte d'Ivoire, on February 4, 2002. Production commenced at 8,500 barrels of oil per day and stabilized at 6,000 barrels of oil per day from one producing well. In the North Sea production is approximately 5,000 barrels per day lower than the fourth quarter of 2001 due to the effect of a property exchange and the implementation of reservoir management techniques designed to enhance the ultimate recovery factor from the Banff and Kyle fields.

The Company's production composition is as follows:

	Q1 2002		Q4 2001		Q1 2001	
	mboe/d	*%*	*mboe/d*	*%*	*mboe/d*	*%*
Natural gas	**175.6**	**48**	168.6	46	141.8	41
Light oil and NGLs	**72.2**	**20**	74.5	20	65.1	19
Pelican Lake oil	**26.6**	**7**	30.8	9	39.9	11
Primary heavy oil	**48.0**	**13**	53.2	14	56.9	16
Thermal heavy oil	**41.6**	**12**	39.5	11	43.7	13
	364.0		366.6		347.4	

During 2002, Canadian Natural expects production to average between 1,075 to 1,125 million cubic feet per day of natural gas and between 200 to 210 thousand barrels per day of oil and liquids.

DRILLING ACTIVITY *(number of wells)*

	THREE MONTHS ENDED MARCH 31			
	2002		**2001**	
	Gross	**Net**	**Gross**	**Net**
Oil	**55**	**47**	123	109
Natural gas	**103**	**95**	199	163
Dry	**14**	**13**	22	20
Subtotal	**172**	**155**	344	292
Injection/strat tests	**409**	**403**	241	240
Total	**581**	**558**	585	532
Success rate *(excluding injection/strat tests)*		**92%**		93%

Canadian Natural drilled 47 net oil wells and 95 net natural gas wells during the first quarter 2002. These wells were concentrated in the Company's oil area of North Alberta/West Saskatchewan and its natural gas core areas in Northeast British Columbia/Northwest Alberta, South Alberta and North Alberta/West Saskatchewan. In addition, 401 stratigraphic test wells were drilled on the oil sands leases in Horizon Oil Sands Project and in North Alberta/West Saskatchewan. The total success rate for Canadian Natural's drilling program was 92%, excluding injection/stratigraphic test wells.

This drilling program (excluding injection/stratigraphic test wells) represents a 47% decrease from the first quarter of 2001, comprised of a 42% reduction in natural gas well drilling and a 57% reduction in oil well drilling. This reflects the Company's continued discipline in heavy oil drilling and a shift in natural gas drilling to deeper exploration prospects in northeast British Columbia.

Pricing

Netbacks received for Canadian Natural's heavy oil and Pelican Lake oil production improved in the first quarter of the year, and indications are that this will continue into the second quarter as seasonal demand increases and a heavy oil refinery in the US midwest reaches full capacity following a major fire in late August of last year. A comparison of the price received for the Company's North American production is as follows:

	May 7, 2002 Pricing Indications	Q1/02	Q4/01	Q1/01
WTI benchmark price *(US $/bbl)*	**$ 26.63**	**$ 21.67**	$ 20.49	$ 28.72
Differential to LLB blend *(US $/bbl)*	**$ 5.50**	**$ 5.73**	$ 10.07	$ 12.99
Condensate benchmark price *(US $/bbl)*	**$ 27.98**	**$ 20.83**	$ 19.64	$ 33.22
NYMEX benchmark price *(US $/mmbtu)*	**$ 3.67**	**$ 2.40**	$ 2.50	$ 7.28
AECO benchmark price *(Cdn $/mmbtu)*	**$ 4.30**	**$ 3.35**	$ 3.30	$ 10.90
Canadian Natural's Wellhead Price[(1)]				
Light oil and NGLs *(Cdn $/bbl)*	**$ 36.50**	**$ 27.83**	$ 29.42	$ 38.53
Pelican Lake oil *(Cdn $/bbl)*	**$ 27.70**	**$ 21.89**	$ 17.40	$ 16.78
Primary heavy oil *(Cdn $/bbl)*	**$ 26.50**	**$ 20.54**	$ 15.77	$ 13.96
Thermal heavy oil *(Cdn $/bbl)*	**$ 25.60**	**$ 19.40**	$ 13.59	$ 11.20
Natural gas *(Cdn $/mcf)*	**$ 4.05**	**$ 3.05**	$ 2.94	$ 9.30

(1) *Including financial instruments.*

ACTIVITY BY CORE REGION

	Net Undeveloped Land as at March 31, 2002 *(thousands of net acres)*	Drilling Activity Period ended March 31, 2002 *(net wells)*
Northeast British Columbia/Northwest Alberta	**1,562**	**38**
North Alberta/West Saskatchewan	**3,724**	**230**
Horizon Oil Sands	**236**	**256**
South Alberta	**676**	**31**
Southeast Saskatchewan	**155**	**1**
United Kingdom North Sea	**237**	**1**
Offshore West Africa	**1,094**	**1**

North America Conventional

At the Ladyfern field total production from the field is subject to a production cap agreed to with other producers in the area. The total cap in place effective December 1, 2001, amounted to 540 million cubic feet per day. As additional pipeline takeaway capacity was added in March 2002, the cap was increased to 785 million cubic feet per day. Canadian Natural's share of this production cap is established on the basis of productive well capability and during the latest production month of April 2002, Canadian Natural produced 179 million cubic feet per day of the field's total production of 622 million cubic feet per day.

During the quarter Canadian Natural drilled nine Slave Point wells, with four development wells in the main Ladyfern pool. The 2-K well encountered gas over water, establishing the western extent of the productive structure. Of five Slave Point exploration wells targeting larger structures in the immediate Ladyfern vicinity, one successful well was tied in during late March and is currently producing at 17 million cubic feet per day. At least three more Slave Point wells will be drilled on other Ladyfern look-a-like structures during the second and third quarters. These features have been delineated from extensive 3-D seismic programs and have the potential to contain major reserves.

Commencement of the experimental Pelican Lake emulsion flood commenced in April 2002 with injection rates of 900 barrels per day, exceeding initial expectations. If successful, this project will substantially increase the recovery factor from the thin Pelican Lake sands. This field contains approximately three billion barrels of original oil in place but is only expected to achieve a 6% recovery factor using primary technologies. Based upon positive laboratory testing, this project could double or triple recovery factors if the technology can be implemented in the field. Data will continue to be gathered on the success of this test throughout the second and third quarters of 2002.

North America Horizon Oil Sands Project

During the first quarter, the Company commenced second phase engineering and drilled an additional 256 stratigraphic test wells on the Horizon lease further confirming commercial viability of the lease for open pit mining. Regulatory submissions, including an Environmental Impact Assessment and Project Description, approached 80% completion with anticipated filing in the summer of 2002. The proposed project will provide for a potential recovery of nearly six billion barrels of bitumen over an estimated 50-year life span. The project will involve three major components: surface mining and bitumen extraction, an upgrader and associated infrastructure. Construction is estimated to start in 2004, once necessary regulatory approvals are received and detailed engineering is approximately 80% completed. Commissioning and start-up is expected in late 2007 at 110,000 barrels per day of synthetic light sweet crude oil, with full production capacity of 232,000 barrels per day by 2011. Opportunities for up to an additional 70,000 barrels per day of in-situ recoveries are also possible from this lease.

United Kingdom

During the quarter, Canadian Natural pursued its strategy of holding predominant interests in its assets by completing two property transactions which resulted in a realignment of ownership interests in the North Sea. Effective February 1, 2002, the Company swapped its entire 15.6% interest in the Pierce field for cash and a further 29.7% interest in the Banff field. The Company now owns a majority 55.9% interest of the Banff field. Effective March 1, 2002, the Company acquired an additional 5.7% interest in the Kyle field, resulting in a total ownership interest of 45.7% in this operated property. Both the Banff and Kyle fields are located in the central North Sea with the Kyle field connecting to the Canadian Natural operated Curlew floating production storage and offtake ("FPSO") vessel.

Offshore West Africa

During the quarter, Canadian Natural continued the development of the 59% owned and operated Espoir field located offshore Côte d'Ivoire. This development included the completion of one producing well and two water injection wells. Production to the FPSO vessel, the "Espoir Ivoirien", commenced in February 2002. The second producing well has since been drilled and will be flow tested in May. It contains 1,380 feet of net oil pay. This compares with 696 feet in the first producing well which gave an initial flow rate of 8,500 barrels of oil per day gross and a current stabilized rate of 6,000 barrels of oil per day. Additional producing wells are to be added in June, August and October 2002, which is expected to increase total field production to 30,000 barrels of oil per day.

In deeper water south of Espoir, Canadian Natural drilled a second Baobab exploratory well, which tested at a rate in excess of 10,000 barrels of oil per day, confirming commercial viability of the prospect with recoverable reserves in excess of 150 million barrels. Located southeast of the Baobab discovery, an exploration well in the Kossipo project was drilled. Core samples identified 25 net feet of light oil bearing sands in a rotated fault trap similar to the Baobab and Espoir fields. This result is not considered commercial at this time but may lead to further drilling on the second fault block if it can be combined with another structure to the north. Canadian Natural is operator and holds a 61% working interest in these projects.

Production from the Kiame field in offshore Angola ceased in April 2002. This field was acquired as part of the Ranger Oil acquisition during 2000 and at that time, it was expected that production would likely become uneconomic in 2001. Offshore Angola, Canadian Natural participated with a 25% interest in the Mariposa well located in Block 19, which was dry and abandoned. The operator is currently evaluating a second commitment well location.

FINANCIAL REVIEW

Canadian Natural recognizes the need for a strong financial position in order to withstand volatile oil and natural gas commodity prices and the operational risks inherent in the oil and natural gas business environment.

Long-term debt at March 31, 2002 amounted to $2.7 billion and reflected a 1.7x debt to cash flow ratio and a debt to book capitalization of 42.3%, both reflecting our preferred securities as debt equivalents and the debt to cash flow ratio calculated on a trailing 12-month activity basis. These ratios are well within the Company's guidelines for balance sheet management.

Canadian Natural maintains shelf prospectuses in Canada and the United States for the separate offering of up to $1 billion of medium term notes in Canada and up to US $1 billion of debt securities in the United States. The securities, if and when issued, will be unsecured and will rank pari passu with other senior unsecured indebtedness of Canadian Natural.

Following a 2001 issuance of US $400 million of ten-year, 6.70% notes to purchasers in the United States under the above US shelf prospectus, the Company issued US $400 million of 30-year, 7.20% notes to purchasers in the United States during January 2002. Net proceeds from both issuances were used to repay bank indebtedness. The securities were rated "Baa1" by Moody's Investors Service, Inc., "BBB+" by Standard & Poor's Corporation and "BBB (high)" by Dominion Bond Rating Service Limited. Future offerings under the shelf prospectuses will provide flexibility to the Company's debt investment base, extend maturities and provide balance in fixed/floating interest rate ratios.

In response to the expected demand for oil and natural gas, the related pricing and to protect capital expenditure programs, the Company has entered into several financial instruments to manage exposure to market volatility. The details of these positions are set out in note 6 to the consolidated financial statements and are summarized as follows:

		Q2 2002		Q3 2002		Q4 2002
Oil Collars *(US$ - WTI)*						
Volume *(mbbl/d)*		**100.0**		**100.5**		**100.5**
Average floor price *(US $/bbl)*	$	**19.90**	$	**21.04**	$	**21.04**
Average ceiling price *(US $/bbl)*	$	**24.06**	$	**26.59**	$	**26.59**
Natural Gas Collars *(Cdn $ - AECO)*						
Volume *(mGJ/d)*		**280**		**50**		**-**
Average floor price *(Cdn $/GJ)*	$	**3.42**	$	**3.08**	$	**-**
Average ceiling price *(Cdn $/GJ)*	$	**4.19**	$	**3.80**	$	**-**

Canadian Natural's financial position is strong and management will continue to adhere to long-term targets, ensuring our financial flexibility. In light of this, the Board of Directors announced that the quarterly dividend would increase to $0.125 per common share from $0.10 per common share commencing with the April 1, 2002 payment. The second quarter payment will occur on July 1, 2002 and will be made to shareholders of record at the close of business on June 14, 2002.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") of the financial condition and results of operations should be read in conjunction with the unaudited interim consolidated financial statements for the three months ended March 31, 2002 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2001.

Per barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

	THREE MONTHS ENDED MARCH 31 2002	DECEMBER 31 2001[1]	MARCH 31 2001[1]
FINANCIAL HIGHLIGHTS *($ millions, except per share amounts)*			
Revenue	**$ 718**	$ 667	$ 1,131
Cash flow from operations attributable to common shareholders[2]	**$ 359**	$ 326	$ 629
Per share – basic	**$ 2.95**	$ 2.69	$ 5.15
– diluted	**$ 2.85**	$ 2.65	$ 5.03
Net earnings attributable to common shareholders[2]	**$ 99**	$ 53	$ 222
Per share – basic	**$ 0.81**	$ 0.44	$ 1.82
– diluted	**$ 0.79**	$ 0.43	$ 1.77
Capital expenditures, net of dispositions	**$ 459**	$ 530	$ 635

[1] *Restated for change in accounting policy (see financial statement notes 1 and 2).*
[2] *After dividend and revaluation on preferred securities.*

OPERATING HIGHLIGHTS

	MARCH 31 2002	DECEMBER 31 2001	MARCH 31 2001
Oil and liquids *($/bbl, except daily production)*			
Daily production *(bbls/d)*	**188,439**	198,000	205,588
Sales price	**$ 24.50**	$ 21.28	$ 22.06
Royalties	**2.28**	1.41	2.36
Production expense	**7.81**	7.52	8.18
Netback [3]	**$ 14.41**	$ 12.35	$ 11.52
Natural gas *($/mcf, except daily production)*			
Daily production *(mmcf/d)*	**1,053**	1,012	851
Sales price	**$ 3.06**	$ 2.94	$ 9.30
Royalties	**0.55**	0.62	2.40
Production expense	**0.58**	0.53	0.50
Netback [3]	**$ 1.93**	$ 1.79	$ 6.40
Barrels of oil equivalent *($/boe, except daily production)*			
Daily production *(boe/d)*	**363,990**	366,594	347,382
Sales price	**$ 21.58**	$ 19.62	$ 35.85
Royalties	**2.78**	2.47	7.27
Production expense	**5.73**	5.53	6.07
Netback [3]	**$ 13.07**	$ 11.62	$ 22.51

[3] *Netbacks do not include midstream operations.*

Cash flow and net earnings for the three months ended March 31, 2002, increased from the fourth quarter of 2001 due to higher product prices for both oil and natural gas and increased natural gas production. Cash flow and net earnings decreased from the same period in 2001 primarily as a result of lower natural gas prices and lower oil production.

	THREE MONTHS ENDED		
	MARCH 31 2002	DECEMBER 31 2001	MARCH 31 2001
DAILY PRODUCTION			
Oil and liquids *(bbls/d)*			
North America	**152,268**	159,000	176,102
North Sea	**30,910**	35,749	27,210
Offshore West Africa	**5,261**	3,251	2,276
Total	**188,439**	198,000	205,588
Natural gas *(mmcf/d)*			
North America	**1,026**	993	851
North Sea	**27**	19	-
Total	**1,053**	1,012	851
Product mix			
Light oil and NGLs	**19.9%**	20.3%	18.7%
Pelican Lake oil	**7.3%**	8.4%	11.5%
Primary heavy oil	**13.2%**	14.5%	16.4%
Thermal heavy oil	**11.4%**	10.8%	12.6%
Natural gas	**48.2%**	46.0%	40.8%

Oil and liquids production decreased from the comparable periods in 2001 due to the Company's focus on natural gas development opportunities in the prior year and the decision to curtail 15,000 barrels of oil per day of its North American heavy oil production last December. Oil and liquids production also decreased due to the substantial reduction in the number of primary heavy oil wells that were drilled in the first quarter 2002 and the extension of Primrose steam cycles and the resulting delay in associated oil recovery cycles. These actions were in response to the decline in world oil prices in late 2001 and unusually high heavy oil differentials. A portion of the curtailed production is currently being brought back on stream. Oil and liquids production from the North Sea decreased from the previous quarter due to the implementation of reservior management techniques designed to enhance the ultimate recovery factor from the Banff and Kyle fields. Production was also reduced due to the Company exchanging its interest in the Pierce field for an additional interest in the Banff field (see capital expenditures section). Offshore West Africa oil and liquids production increased from the comparable periods in 2001 as a result of production commencing from the Company's operated Espoir field, located offshore Côte d'Ivoire, in February 2002. Production from this field is anticipated to increase over the next several months as six additional wells are scheduled to be drilled during the first phase of development. As planned, production from the Kiame field in Angola ceased in April 2002.

Natural gas production increased from the comparable periods in 2001 as a result of the focus of the 2001 capital expenditure program on natural gas development, which resulted in the discovery of the Ladyfern field. Production from the Ladyfern field increased over the prior periods due to the commissioning of the Ladyfern sales pipeline in March 2002, which increased takeaway capacity. Natural gas production in the North Sea increased due to an additional working interest being acquired in the Banff field.

		THREE MONTHS ENDED				
		MARCH 31 2002		DECEMBER 31 2001		MARCH 31 2001
PRODUCT PRICES						
Oil and liquids *($/bbl)*						
North America	**$**	**22.18**	$	18.59	$	18.88
North Sea	**$**	**33.75**	$	33.39	$	41.04
Offshore West Africa	**$**	**37.61**	$	19.56	$	40.58
Company average	**$**	**24.50**	$	21.28	$	22.06
Natural gas *($/mcf)*						
North America	**$**	**3.05**	$	2.94	$	9.30
North Sea	**$**	**3.77**	$	3.00	$	-
Company average	**$**	**3.06**	$	2.94	$	9.30
Percentage of gross revenue						
Oil and liquids		**58.9%**		58.6%		36.5%
Natural gas		**41.1%**		41.4%		63.5%

The North American realized oil price increased from the comparable periods in 2001 due to lower heavy oil differentials and from the prior quarter due to an increase in world oil prices. In the first quarter of 2002, WTI averaged US $21.67 per bbl compared to US $20.49 per bbl in the fourth quarter of 2001 and US $28.72 per bbl in the first quarter of 2001. Heavy oil differentials averaged US $5.73 per bbl in the first quarter of 2002 compared to US $10.07 per bbl in the fourth quarter of 2001 and US $12.99 per bbl in the first quarter of 2001. The WTI price strengthened throughout the first quarter of 2002 as a result of improved supply and demand fundamentals as OPEC cut production and the economic outlook improved.

Natural gas prices decreased from the same period in 2001 due to lower demand in the North American market and warmer than average winter temperatures, which resulted in higher natural gas storage levels.

Financial instruments were entered into by the Company to protect the downside prices received on the sale of a portion of its oil and natural gas production. The price realized from the sale of oil was reduced by $0.50 per bbl in the quarter ended March 31, 2002 ($4.33 per bbl increase and $0.08 per bbl reduction, respectively, in the quarters ended December 31, 2001 and March 31, 2001). The price realized from the sale of natural gas was increased by $0.08 per mcf in the first quarter of 2002 (reductions of $0.03 per mcf and $0.80 per mcf, respectively, in the quarters ended December 31, 2001 and March 31, 2001).

	THREE MONTHS ENDED MARCH 31 2002	DECEMBER 31 2001	MARCH 31 2001
ROYALTIES			
Oil and liquids *($/bbl)*			
North America	**$ 2.46**	$ 1.40	$ 2.30
North Sea	**$ 1.54**	$ 1.52	$ 2.86
Offshore West Africa	**$ 1.65**	$ 0.64	$ -
Company average	**$ 2.28**	$ 1.41	$ 2.36
Natural gas *($/mcf)*			
North America	**$ 0.57**	$ 0.63	$ 2.40
Company average	**$ 0.55**	$ 0.62	$ 2.40
Company average *($/boe)*	**$ 2.78**	$ 2.47	$ 7.27
Percentage of revenue *(excluding financial instruments)*			
Oil and liquids	**9.1%**	8.3%	10.6%
Natural gas	**18.5%**	20.8%	23.7%

Oil and liquids royalties in North America increased over the comparable periods mainly due to higher product prices as a result of lower heavy oil differentials. North Sea oil and liquids royalties decreased from the same period in 2001 due to lower world oil prices and increased production from the non-royalty paying Banff and Kyle fields. Offshore West Africa royalties increased as a result of higher product prices.

North American natural gas royalties declined from the same period last year due to the decrease in natural gas prices.

	THREE MONTHS ENDED MARCH 31 2002	DECEMBER 31 2001	MARCH 31 2001
PRODUCTION EXPENSE			
Oil and liquids *($/bbl)*			
North America	**$ 6.97**	$ 6.60	$ 7.63
North Sea	**$ 10.09**	$ 10.54	$ 9.22
Offshore West Africa	**$ 18.62**	$ 19.15	$ 38.80
Company average	**$ 7.81**	$ 7.52	$ 8.18
Natural gas *($/mcf)*			
North America	**$ 0.56**	$ 0.52	$ 0.50
North Sea	**$ 1.33**	$ 1.34	$ -
Company average	**$ 0.58**	$ 0.53	$ 0.50
Company average *($/boe)*	**$ 5.73**	$ 5.53	$ 6.07

North American oil and liquids production expense decreased from the same period in 2001 due to lower costs of natural gas, which is used to produce the steam to heat thermal heavy oil formations. Oil and liquids production expense increased from the prior quarter due to higher steam rates in response to the narrowing of heavy oil differentials. Offshore West Africa oil and liquids production expense decreased from the comparable periods in the prior year due to higher production from the Kiame field and the commencement of production from the Espoir field in February 2002. Costs are expected to decline as production from the Espoir field increases and the Kiame field ceases production in April 2002.

Natural gas production expense increased over the comparable periods due to an increase in the toll rates and the percentage of natural gas produced through the gathering and processing system in British Columbia. Natural gas production expense is expected to decrease as a result of the commissioning of the Ladyfern sales pipeline and the expiry of the Ladyfern McMahon service fee at the end of June 2002.

	THREE MONTHS ENDED MARCH 31 2002	DECEMBER 31 2001	MARCH 31 2001
DEPLETION, DEPRECIATION AND AMORTIZATION[1]			
Expense *($ millions)*	**$ 232.0**	$ 241.2	$ 207.2
$/boe	**$ 7.08**	$ 7.15	$ 6.63

[1] *DD&A does not include midstream operations.*

Depletion, depreciation and amortization ("DD&A") increased from the same period in 2001 due to higher finding and development costs associated with natural gas exploration during 2001 and higher production. DD&A costs decreased from the prior quarter due to the inclusion of a provision for the remainder of the abandonment costs of the Kiame field in Angola in the fourth quarter 2001 and lower production in the first quarter 2002.

	THREE MONTHS ENDED MARCH 31 2002	DECEMBER 31 2001	MARCH 31 2001
ADMINISTRATION EXPENSE			
Net expense *($ millions)*	**$ 13.5**	$ 12.0	$ 8.3
$/boe	**$ 0.41**	$ 0.36	$ 0.26

The Company's administration expense increased from comparable periods in 2001 due to higher compensation costs associated with increased staffing levels and lower capital recoveries on reduced capital spending.

	THREE MONTHS ENDED MARCH 31 2002	DECEMBER 31 2001	MARCH 31 2001
INTEREST EXPENSE			
Interest expense *($ millions)*	**$ 28.7**	$ 31.4	$ 39.4
$/boe	**$ 0.88**	$ 0.93	$ 1.26
Average effective interest rate	**4.12%**	4.23%	6.25%

Interest expense decreased from the comparable periods in the prior year due to a lower average effective interest rate.

MIDSTREAM *($ millions)*	THREE MONTHS ENDED MARCH 31 2002	DECEMBER 31 2001	MARCH 31 2001
Revenue	**$ 10.4**	$ 4.9	$ 9.8
Operating costs	**3.1**	2.9	4.1
Cash flow	**7.3**	2.0	5.7
Depreciation	**1.9**	1.2	0.9
Segment earnings before taxes	**$ 5.4**	$ 0.8	$ 4.8

As midstream operations form an increasing part of the Company's business and are more strategic to its business plan, the Company believes it is financially prudent to report this as a separate operating segment.

The Company's midstream assets consist of the 100% owned and operated ECHO pipeline, the 15% interest in the Cold Lake pipeline system, the 62% interest in the operated Pelican Lake pipeline and the 50% interest in the 80 megawatt co-generation system located in the Primrose area. The midstream pipeline assets allow the Company to transport its own production volumes as well as earn third party revenue from excess capacity. Through these assets, the Company transports in excess of 75% of its heavy oil to the international mainline liquid pipelines. These midstream assets enhance the Company's ability to control the full range of costs associated with the development and marketing of its heavy oil.

Revenue from midstream assets increased from the prior quarter due to the expansion of the ECHO pipeline and the commencement of operations from the Cold Lake pipeline system in late December 2001. The increased pipeline revenues offset the decline in electricity revenue. Electricity revenues declined over the same period in 2001 due to lower prices received.

TAXES *($ millions)*	THREE MONTHS ENDED MARCH 31 2002	DECEMBER 31 2001	MARCH 31 2001
Taxes other than income tax			
Current	**$ 13.5**	$ 10.1	$ 17.1
Deferred	**1.4**	1.0	0.8
Total	**$ 14.9**	$ 11.1	$ 17.9
Current income tax			
North Sea	**$ 11.0**	$ 10.3	$ 9.8
Offshore West Africa	**0.5**	-	-
Large Corporations Tax	**4.3**	4.7	3.9
Total	**$ 15.8**	$ 15.0	$ 13.7
Future income tax	**$ 38.3**	$ 1.8	$ 155.2
Effective income tax rate	**35.0%**	22.2%	38.7%

Taxes other than income taxes consist of current and deferred petroleum revenue tax and other international taxes and provincial resource surcharges. Changes in taxes other than income taxes from period to period are a direct result of changes in oil prices received, primarily the North Sea.

Future income tax expense increased from the prior quarter as a result of increased earnings before taxes. Fourth quarter 2001 also included a reduction in the future income tax liability due to a decrease in a Canadian province's corporate income tax rate. The Company's future income taxes payable and property, plant and equipment have been decreased by $23.2 million to provide for the exchange of non-tax base assets in the North Sea in the first quarter of 2002.

In its 2002 budget speech, the UK Government announced a new supplementary charge of 10% on profits from North Sea oil and natural gas production and changes to certain capital allowance rates. The supplementary charge is in addition to the current corporate tax rate of 30%. The supplementary charge takes effect April 17, 2002 and excludes any deduction for financing costs. To promote additional investment in the North Sea, the government increased the capital allowance rate for plant and machinery expenditures to 100% from the current rate of 25%. Due to several uncertainties, the Company cannot estimate the effects of this proposed legislation at this time. The North Sea future income tax expense will increase in the second quarter 2002 once the legislation is enacted. In addition, the second quarter 2002 will include a future tax reduction due to a corporate income tax rate decrease proposed by a province in Canada.

	THREE MONTHS ENDED		
	MARCH 31 2002	**DECEMBER 31 2001**	**MARCH 31 2001**
CAPITAL EXPENDITURES *($ millions)*			
Expenditures on property, plant and equipment			
Net property acquisitions	**$ 35.3**	$ 248.4	$ 190.7
Land acquisition and retention	**27.8**	15.5	27.7
Seismic evaluations	**24.8**	28.8	37.0
Well drilling, completion and equipping	**206.8**	106.5	236.3
Pipeline and production facilities	**124.3**	68.9	111.4
Total net reserve replacement expenditures	**419.0**	468.1	603.1
Project Horizon	**22.3**	11.0	-
Midstream	**9.6**	45.5	28.9
Abandonments	**6.8**	3.4	1.2
Head office	**1.1**	1.7	1.5
Total net capital expenditures	**$ 458.8**	$ 529.7	$ 634.7
By segment			
North America	**$ 420.1**	$ 406.8	$ 549.2
North Sea	**(31.4)**	34.3	14.8
Offshore West Africa	**60.5**	43.1	41.8
Midstream	**9.6**	45.5	28.9
Total	**$ 458.8**	$ 529.7	$ 634.7

North America capital expenditures include natural gas exploration that concentrated on larger outlying pools in the Ladyfern area. A total of five prospects were drilled in the first quarter 2002, resulting in one successful well. The Company is currently drilling two additional Slave Point wells in northeast British Columbia on prospects identified with its extensive 2-D and 3-D seismic. The first quarter 2002 also saw the construction and commissioning of the Ladyfern natural gas sales pipeline. This 20", 7.5 mile pipeline connects the Ladyfern field to the TransCanada Pipelines Limited Owl Lake South meter station in Alberta and has a capacity of 600 mmcf/day. The Company also acquired approximately 3,700 bbls/day of oil properties in southeast Saskatchewan and Manitoba during the quarter.

North Sea capital expenditures include the consolidation of interests in both the Banff and Kyle fields. In exchange for an additional 29.7% interest in Banff and cash, the Company sold its 15.6% interest in the Pierce field. The Company now holds a 55.9% interest in the Banff field. The Company also acquired an additional 5.71% interest in the operated Kyle field, increasing its interest to 45.71%.

Offshore West Africa capital expenditures include the continued development of the Espoir field located offshore Côte d'Ivoire. During the first quarter, one producing well and two water injection wells were completed. Late in the first quarter, a second producer well was spudded and is expected to be tied in during the second quarter. Five additional wells are planned to be drilled in the first development phase during the remainder of 2002. The first quarter 2002 included the drilling of a second successful appraisal well in the Baobab prospect. This well tested at a rate in excess of 10,000 bbls/day and further defined the extent and size of the Baobab field. A well was also drilled in the Kossipo field, encountering 25 feet of net pay of light oil; however, the field is not considered economic for commercial development at this time.

	MARCH 31 2002	DECEMBER 31 2001	MARCH 31 2001
LIQUIDITY AND CAPITAL RESOURCES *($ millions, except ratios)*			
Working capital deficit	**$ 84.5**	$ 5.6	$ 230.7
Long-term debt	**2,658.1**	2,669.2	2,377.9
Total	**$ 2,742.6**	$ 2,674.8	$ 2,608.6
Shareholders' equity			
Preferred securities	**$ 127.5**	$ 127.4	$ 126.2
Share capital	**1,739.2**	1,698.3	1,691.5
Retained earnings	**1,992.2**	1,908.5	1,580.7
Foreign currency translation adjustment	**69.2**	72.8	-
Total	**$ 3,928.1**	$ 3,807.0	$ 3,398.4
Debt to cash flow(1)	**1.6x**	1.4x	1.1x
Debt to book capitalization	**40.4%**	41.2%	41.2%
Debt to market capitalization	**29.2%**	34.9%	29.5%
After tax return on average common shareholders' equity(1)	**14.6%**	18.7%	31.7%
After tax return on average capital employed(1)	**9.7%**	12.2%	18.4%

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

The ratios above have been calculated with the outstanding preferred securities of the Company classified as equity. If the preferred securities were classified as long-term debt, debt to cash flow for the trailing 12-month activity ending March 31, 2002, would be 1.7x (December 31, 2001 – 1.5x, March 31, 2001 – 1.2x). Debt to book capitalization would be 42.3% at March 31, 2002 (December 31, 2001 – 43.2%, March 31, 2001 – 43.4%) had the preferred securities been classified as long-term debt, while debt to market capitalization would be 30.6%, 36.6% and 31.0%, respectively.

SENSITIVITY ANALYSIS [1]

Annualized sensitivities to certain factors, which would influence the Company's financial results, are estimated as follows:

	Cash flow from operations[2] ($ millions)	Cash flow from operations[2] (per share) (basic)	Net earnings[2] ($ millions)	Net earnings[2] (per share) (basic)
Price changes				
Oil – WTI US $1.00/bbl[3]				
Excluding financial derivatives	$90	$0.74	$63	$0.52
Including financial derivatives	$75 – $79	$0.62 – $0.65	$53 – $56	$0.44 – $0.46
Natural gas – AECO Cdn $0.10/mcf[3]				
Excluding financial derivatives	$31	$0.25	$19	$0.15
Including financial derivatives	$28	$0.23	$17	$0.14
Volume changes				
Oil – 10,000 bbls/d	$43	$0.35	$11	$0.09
Natural gas – 10 mmcf/d	$7	$0.06	$2	$0.01
Foreign currency rate change				
$0.01 change in Cdn $ in relation to US $[3]				
Excluding financial derivatives	$37	$0.30	$22	$0.18
Including financial derivatives	$27 – $33	$0.23 – $0.27	$17 – $20	$0.14 – $0.16
Interest rate change - 1%	$21	$0.17	$13	$0.11

(1) *The sensitivities are calculated based on 2002 first quarter results.*

(2) *Attributable to common shareholders.*

(3) *For details of financial instruments in place, see financial statement note 6.*

OTHER OPERATING HIGHLIGHTS

	THREE MONTHS ENDED MARCH 31 2002	THREE MONTHS ENDED DECEMBER 31 2001	THREE MONTHS ENDED MARCH 31 2001
NETBACK ANALYSIS *($/boe, except daily production)*			
Daily production *(boe/d)*	**363,990**	366,594	347,382
Sales price	**$ 21.58**	$ 19.62	$ 35.85
Royalties	**2.78**	2.47	7.27
Production expense	**5.73**	5.53	6.07
Netback	**13.07**	11.62	22.51
Midstream contribution	**(0.22)**	(0.06)	(0.18)
Administration	**0.41**	0.36	0.26
Interest	**0.88**	0.93	1.26
Foreign exchange loss (gain)	**0.07**	(0.09)	(0.03)
Taxes other than income tax (current)	**0.41**	0.30	0.55
Current income tax (North Sea)	**0.33**	0.31	0.32
Current income tax (Offshore West Africa)	**0.02**	-	-
Current income tax (Large Corporations Tax)	**0.13**	0.14	0.12
Cash flow	**$ 11.04**	$ 9.73	$ 20.21

	THREE MONTHS ENDED MARCH 31, 2002 North America	North Sea	Offshore West Africa	Total
SEGMENTED NETBACK				
Oil and liquids *($/bbl, except daily production)*				
Daily production *(bbls/d)*	**152,268**	**30,910**	**5,261**	**188,439**
Sales price	**$ 22.18**	**$ 33.75**	**$ 37.61**	**$ 24.50**
Royalties	**2.46**	**1.54**	**1.65**	**2.28**
Production expense	**6.97**	**10.09**	**18.62**	**7.81**
Netback[1]	**$ 12.75**	**$ 22.12**	**$ 17.34**	**$ 14.41**
Natural gas *($/mcf, except daily production)*				
Daily production *(mmcf/d)*	**1,026**	**27**	**-**	**1,053**
Sales price	**$ 3.05**	**$ 3.77**	**$ -**	**$ 3.06**
Royalties	**0.57**	**-**	**-**	**0.55**
Production expense	**0.56**	**1.33**	**-**	**0.58**
Netback[1]	**$ 1.92**	**$ 2.44**	**$ -**	**$ 1.93**
Barrels of oil equivalent *($/boe, except daily production)*				
Daily production *(boe/d)*	**323,340**	**35,389**	**5,261**	**363,990**
Sales price	**$ 20.13**	**$ 32.49**	**$ 37.61**	**$ 21.58**
Royalties	**2.95**	**1.34**	**1.65**	**2.78**
Production expense	**5.08**	**9.82**	**18.62**	**5.73**
Netback[1]	**$ 12.10**	**$ 21.33**	**$ 17.34**	**$ 13.07**

[1] *Netbacks do not include midstream operations.*

CONSOLIDATED BALANCE SHEETS *(millions of Canadian dollars) (unaudited)*

	MARCH 31 2002	DECEMBER 31 2001
ASSETS		
Current assets		
Cash	$ 36.2	$ 15.0
Accounts receivable and other	616.4	509.0
	652.6	524.0
Property, plant and equipment *(net)*	8,648.3	8,442.9
	$ 9,300.9	$ 8,966.9
LIABILITIES		
Current liabilities		
Accounts payable	$ 254.7	$ 249.5
Accrued liabilities	466.5	264.2
Current portion of long-term debt *(note 3)*	15.9	15.9
	737.1	529.6
Long-term debt *(note 3)*	2,658.1	2,669.2
Future site restoration	195.5	193.8
Future income tax	1,782.1	1,767.3
	5,372.8	5,159.9
SHAREHOLDERS' EQUITY		
Preferred securities *(note 2)*	127.5	127.4
Share capital *(note 4)*	1,739.2	1,698.3
Retained earnings	1,992.2	1,908.5
Foreign currency translation adjustment	69.2	72.8
	3,928.1	3,807.0
	$ 9,300.9	$ 8,966.9

CONSOLIDATED STATEMENTS OF EARNINGS *(millions of Canadian dollars, except per share amounts) (unaudited)*

	THREE MONTHS ENDED MARCH 31 2002	2001
Revenue *(note 7)*	**$ 717.5**	$ 1,130.7
Less: royalties	**(91.0)**	(227.2)
	626.5	903.5
Expenses		
Production	**190.9**	194.1
Depletion, depreciation and amortization	**233.9**	208.1
Administration	**13.5**	8.3
Interest	**28.7**	39.4
Foreign exchange (gain) loss *(note 2)*	**(10.0)**	37.4
	457.0	487.3
Earnings Before Taxes	**169.5**	416.2
Taxes other than income tax	**14.9**	17.9
Current income tax	**15.8**	13.7
Future income tax	**38.3**	155.2
Net Earnings	**100.5**	229.4
Dividend on preferred securities *(net of tax)*	**(1.5)**	(1.4)
Revaluation of preferred securities *(note 2)*	**(0.1)**	(6.2)
Net Earnings Attributable to Common Shareholders	**$ 98.9**	$ 221.8
Net earnings per common share attributable to common shareholders *(note 5)*		
Basic	**$ 0.81**	$ 1.82
Diluted	**$ 0.79**	$ 1.77

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS *(millions of Canadian dollars)(unaudited)*

	THREE MONTHS ENDED MARCH 31 2002	2001
Balance – Beginning of Period as Previously Reported	**$ 1,979.5**	$ 1,406.0
Change in accounting policy – foreign exchange *(note 2)*	**(71.0)**	(15.4)
Balance – Beginning of Period as Restated	**1,908.5**	1,390.6
Net earnings	**100.5**	229.4
Dividend on common shares *(note 4)*	**(15.2)**	(12.2)
Dividend on preferred securities *(net of tax)*	**(1.5)**	(1.4)
Revaluation of preferred securities *(note 2)*	**(0.1)**	(6.2)
Purchase of common shares *(note 4)*	**-**	(19.5)
Balance – End of Period	**$ 1,992.2**	$ 1,580.7

CONSOLIDATED STATEMENT OF CASH FLOWS *(millions of Canadian dollars) (unaudited)*

	THREE MONTHS ENDED MARCH 31 2002	2001
Operating Activities		
Net earnings	**$ 100.5**	$ 229.4
Non-cash items		
Depletion, depreciation and amortization	**233.9**	208.1
Deferred petroleum revenue tax	**1.4**	0.8
Future income tax	**38.3**	155.2
Unrealized foreign exchange (gain) loss	**(12.3)**	38.3
Cash flow provided from operations	**361.8**	631.8
Net change in non-cash working capital	**(57.5)**	32.0
	304.3	663.8
Financing Activities		
Repayment of bank credit facilities	**(650.5)**	(123.2)
Issue of US debt securities	**641.5**	-
Increase of limited recourse loan	**-**	10.3
Issue of capital stock	**41.9**	10.6
Purchase of common shares	**-**	(31.2)
Dividend on common shares	**(12.1)**	-
Dividend on preferred securities	**(2.7)**	(2.5)
Net change in non-cash working capital	**(7.1)**	5.2
	11.0	(130.8)
Investing Activities		
Expenditures on property, plant and equipment	**(515.1)**	(635.9)
Net proceeds on sale of property, plant and equipment	**56.3**	1.2
Net expenditures on property, plant and equipment	**(458.8)**	(634.7)
Net change in non-cash working capital	**164.7**	104.4
	(294.1)	(530.3)
Increase in Cash	**21.2**	2.7
Cash – Beginning of Period	**15.0**	28.0
Cash – End of Period	**$ 36.2**	$ 30.7
Supplemental disclosure of cash flow information		
Interest paid	**$ 26.3**	$ 34.3
Taxes paid	**$ 29.3**	$ 52.7

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS *(tabular amounts in millions of Canadian dollars)*

1. ACCOUNTING POLICIES

The 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 and methods of computation as the audited consolidated financial statements of the Company as at December 31, 2001, except as described below and in note 2. The interim consolidated financial statements contain disclosures that are supplemental to the Company's annual consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual 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, 2001.

Midstream Operations

As a result of the Company's increasing midstream activities, the Company determined that effective January 1, 2002, the midstream activities within North America constitute a distinct operating segment. The Company carries its midstream assets at the lower of capitalized cost and net recoverable amount. Midstream assets are depreciated based on their estimated useful life of 20 to 30 years.

Comparative Figures

Certain figures provided for prior years have been reclassified to conform to the presentation adopted in 2002.

2. CHANGE IN ACCOUNTING POLICY

Foreign Currency Translation

Effective January 1, 2002, the Company retroactively adopted the Canadian Institute of Chartered Accountants' new accounting standard with respect to foreign currency translation. As a result of adopting this new standard, gains or losses on the translation of long-term debt denominated in US dollars are no longer deferred and amortized over the term of the debt, but are recognized in earnings immediately. This new standard has been adopted retroactively and prior periods have been restated.

The new standard effects the Company's accounting for foreign denominated long-term debt and preferred securities. Adoption of the new accounting policy had the following effects on the Company's consolidated financial statements:

	THREE MONTHS ENDED MARCH 31 2002	THREE MONTHS ENDED MARCH 31 2001	YEAR ENDED DECEMBER 31 2001
Decrease deferred foreign exchange loss	**$ -**	$ (50.3)	$ (61.9)
Increase preferred securities	**$ 0.1**	$ 7.8	$ 9.1
Decrease opening retained earnings	**$ (71.0)**	$ (15.4)	$ (15.4)
Increase foreign exchange (gain) loss	**$ (2.1)**	$ 36.5	$ 48.1
Increase revaluation of preferred securities	**$ 0.1**	$ 6.2	$ 7.4

3. LONG-TERM DEBT

		MARCH 31 2002		DECEMBER 31 2001
Bank credit facilities				
Canadian dollar debt	$	**666.3**	$	1,003.4
US dollar debt *(2002 - US $100 million, 2001 - US $296 million)*		**159.4**		471.4
Medium-term notes		**250.0**		250.0
US debt securities *(2002 – US $800 million, 2001 – US $400 million)*		**1,274.8**		637.0
Senior unsecured notes *(US $203 million)*		**323.5**		323.3
	$	**2,674.0**	$	2,685.1
Current portion of long-term debt		**(15.9)**		(15.9)
	$	**2,658.1**	$	2,669.2

Bank credit facilities

At March 31, 2002, the Company had unsecured bank credit facilities of approximately $1,840 million comprised of a $100 million operating demand facility, a revolving credit and term loan facility of $1,500 million and a revolving credit and term loan facility of US $150 million.

US debt securities

On January 23, 2002, the Company issued US $400 million of US debt securities, maturing January 15, 2032, bearing interest at 7.20%. Proceeds from the notes issued were used to repay bankers' acceptances under the Company's bank credit facilities, including the US $196 million bankers' acceptances. Subsequently, the Company entered into interest rate swap contracts that convert the fixed rate interest coupon into a floating interest rate for a portion of the term (note 6).

4. SHARE CAPITAL

Issued

	MARCH 31, 2002 Number of shares *(thousands)*		Amount
Common shares			
Balance – January 1, 2002	**121,201**	**$**	**1,698.3**
Exercise of stock options	**1,259**		**39.6**
Issue of flow-through shares *(net of tax)*	**60**		**1.3**
Balance – March 31, 2002	**122,520**	**$**	**1,739.2**

In January 2002, the Company issued 60,000 flow-through common shares to a director of the Company at a price of $39.00 per common share, for total proceeds of $2.3 million. The value of the common shares was determined as the closing market price on The Toronto Stock Exchange on the day prior to the allotment of the common shares.

Normal Course Issuer Bid

On January 17, 2001, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of The Toronto Stock Exchange and the New York Stock Exchange to purchase up to 6,114,726 common shares or 5% of the common shares outstanding of the Company on the date of announcement during the 12-month period beginning January 22, 2001 and ending January 21, 2002. As at January 21, 2002, the Company had purchased 2,537,800 common shares for a total cost of $113.3 million. The excess cost over book value of the shares purchased was applied to contributed surplus and retained earnings.

In January 2002, the Company renewed its Normal Course Issuer Bid, allowing the Company to purchase up to 6,060,180 shares or 5% of the Company's common shares outstanding on the date of announcement, during the 12-month period beginning January 23, 2002 and ending January 22, 2003. As at March 31, 2002, no common shares had been purchased under the renewed Normal Course Issuer Bid.

Dividend policy

On January 17, 2001, the Company announced the payment of a regular quarterly dividend of $0.10 per common share payable in January, April, July and October of each year.

In February 2002, the Board of Directors increased the Company's regular quarterly dividend to $0.125 per common share commencing with the April 1, 2002 payment.

Stock options

	MARCH 31, 2002	
	Stock options *(thousands)*	**Weighted average exercise price**
Outstanding – January 1, 2002	**12,051**	**$ 34.77**
Granted [1]	**1,963**	**38.83**
Exercised	**(1,259)**	**31.42**
Forfeited	**(75)**	**37.03**
Outstanding – March 31, 2002	**12,680**	**$ 35.72**
Exercisable – March 31, 2002	**3,563**	**$ 32.30**

[1] *A portion of stock options granted are conditional upon shareholder approval of an increase in the number of common shares issuable pursuant to the Company's Stock Option Plan.*

Stock-based compensation costs

	THREE MONTHS ENDED MARCH 31	
	2002	**2001**
Stock-based compensation costs	**$** 5.5	$ 4.1
Net earnings attributable to common shareholders		
As reported	**$** 98.9	$ 221.8
Pro forma	**$** 93.4	$ 217.7
Net earnings per common share attributable to common shareholders		
Basic		
As reported	**$** 0.81	$ 1.82
Pro forma	**$** 0.77	$ 1.78
Diluted		
As reported	**$** 0.79	$ 1.77
Pro forma	**$** 0.75	$ 1.73

The pro forma amounts shown above do not include the compensation costs associated with stock options granted prior to January 1, 2000.

	THREE MONTHS ENDED MARCH 31	
	2002	**2001**
Fair value of options granted *(per common share)*		
Directors, officers and executives	**$** 14.49	$ 16.52
Other employees	**$** 11.70	$ 13.60
Risk-free interest rate	3.9%	5.2%
Expected life *(years)*		
Directors, officers and executives	5.5	5.5
Other employees	3.6	3.6
Expected volatility	38%	40%
Expected dividend yield	1.3%	1.0%

5. NET EARNINGS AND CASH FLOW FROM OPERATIONS PER COMMON SHARE

	THREE MONTHS ENDED MARCH 31	
	2002	**2001**
Weighted average common shares outstanding		
Basic	**121,610**	122,100
Diluted	**126,775**	125,115
Net earnings per common share attributable to common shareholders		
Basic	**$ 0.81**	$ 1.82
Diluted	**$ 0.79**	$ 1.77
Cash flow from operations per common share attributable to common shareholders		
Basic	**$ 2.95**	$ 5.15
Diluted	**$ 2.85**	$ 5.03

6. 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 the date hereof:

	Remaining Term	Volume	Average Price	Index
Oil				
Oil price collars	Apr. 2002 – Jun. 2002	49,500 bbls/d	US $19.70 – US $23.36	WTI
	Apr. 2002 – Dec. 2002	50,500 bbls/d	US $20.09 – US $24.74	WTI
	Jul. 2002 – Dec. 2002	50,000 bbls/d	US $22.00 – US $28.46	WTI
Brent differential swaps	Apr. 2002 – Dec. 2002	15,000 bbls/d	US $1.38	Dated Brent/WTI
Natural Gas				
Empress – NYMEX differential swaps	Apr. 2002 – Oct. 2006	5,500 mmbtu/d	US $0.73	Empress/NYMEX
NYMEX swaps	Apr. 2002 – Oct. 2006	10,000 mmbtu/d	Cdn $2.66	NYMEX
Sumas fixed	Apr. 2002 – Oct. 2003	20,000 mmbtu/d	Cdn $2.85	Sumas
AECO collars	Apr. 2002 – Jun. 2002	230,000 GJ/d	Cdn $3.49 – Cdn $4.27	AECO
	Apr. 2002 – Sep. 2002	50,000 GJ/d	Cdn $3.08 – Cdn $3.80	AECO

	Remaining Term	Amount ($ millions)	Average Exchange Rate (US $/Cdn $)
Foreign Currency			
Currency fixed	Apr. 2002 – Oct. 2002	US $0.4/month	1.37
Currency collars	Apr. 2002 – May 2003	US $4.2/month	1.43 – 1.53
	Apr. 2002 – Aug. 2004	US $25.0/month	1.51 – 1.59

	Remaining Term	Amount ($ millions)	Fixed Rate	Floating Rate
Interest Rate				
Swaps – fixed to floating	Apr. 2002 – Jul. 2004	US $200	6.70%	LIBOR + 2.09%
	Apr. 2002 – Jul. 2006	US $200	6.70%	LIBOR + 1.58%
	Apr. 2002 – Jan. 2005	US $200	7.20%	LIBOR + 3.00%
	Apr. 2002 – Jan. 2007	US $200	7.20%	LIBOR + 2.23%

7. SEGMENTED INFORMATION

	THREE MONTHS ENDED MARCH 31 2002	2001
Revenue		
North America	$ **585.8**	$ 1,012.1
North Sea	**103.5**	100.5
Offshore West Africa	**17.8**	8.3
Midstream	**10.4**	9.8
	$ **717.5**	$ 1,130.7
Net Earnings		
North America	$ **72.7**	$ 213.3
North Sea	**20.1**	18.2
Offshore West Africa	**4.6**	(4.8)
Midstream	**3.1**	2.7
	100.5	229.4
Dividend on preferred securities *(net of tax)*	**(1.5)**	(1.4)
Revaluation of preferred securities	**(0.1)**	(6.2)
Net Earnings Attributable to Common Shareholders	$ **98.9**	$ 221.8
Additions to Property, Plant and Equipment		
North America	$ **420.1**	$ 630.3
North Sea	**(54.6)**	14.8
Offshore West Africa	**60.5**	41.8
Midstream	**9.6**	33.9
	$ **435.6**	$ 720.8

Property, plant and equipment and future income taxes payable have been decreased by $23.2 million (2001 increased by $86.1 million) to provide for the tax effect of the sale and acquisition of assets in the North Sea and North America with a tax basis that differs from the purchase and sale price.

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 July 24, 2001. 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 March 31, 2002:	
Interest coverage *(times)*	
Net earnings	7.1[1]
Cash flow	14.7[2]

[1] *Net earnings plus income taxes and interest expense; divided by interest expense.*

[2] *Cash flow 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 March 31, 2002, would be 6.5 and the cash flow coverage ratio for the 12-month period ended March 31, 2002 would be 13.6.

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Daylight Time, 11:00 a.m. Eastern Daylight Time, on Wednesday, May 8, 2002. The North American conference call number is 1-800-482-5519 and the outside North America conference call number is 1-303-267-1006. Please call in about 10 minutes before the starting time in order to be patched into the call. Should you experience difficulty in connecting to the call, those in North America please call 1-800-374-6543 and for those outside North America call 1-303-267-1097.

Media are invited to participate in listen-only mode.

Replay: A taped rebroadcast will be available until May 15, 2002, inclusive. To access postview in North America, dial 1-800-625-5288 and enter the passcode 1744179. Those outside of North America dial 1-303-804-1855 and enter the passcode number 1744179.

ANNUAL GENERAL MEETING

Canadian Natural Resources Limited's Annual Meeting will be held on Thursday, May 9, 2002 at 3:00 p.m. Mountain Daylight Time in the Ballroom of the Metropolitan Centre 333 – 4 Avenue S.W., Calgary, Alberta.

2002 SECOND QUARTER RESULTS

2002 second quarter results are scheduled for release Wednesday, August 7, 2002. A conference call will be held at 9:00 a.m. Mountain Daylight Time, 11:00 a.m. Eastern Daylight Time.

For further information, please contact:

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Chairman

JOHN G. LANGILLE
President

STEVE W. LAUT
Executive Vice-President
Operations

Trading Symbols
Toronto Stock Exchange – **CNQ**
New York Stock Exchange – **CED**