CANADIAN NATURAL RESOURCES LIMITED

INTERIM REPORT 1

For the Three Months Ended March 31, 2001

In commenting on the results Mr. Allan Markin, Chairman, stated "These record results reflect on the diversity and strength of our asset base. In the first quarter we were able to effectively switch some of our heavy oil projects into natural gas projects. With current daily production levels approaching 900 million cubic feet of natural gas and 225,000 barrels of oil and liquids and at the current pricing levels we will achieve our 2001 targeted cash flow of over $2.3 billion. Our 2001 average natural gas production target range has been raised to an average of 850 to 875 million cubic feet per day. We have increased our capital expenditure program to $1.7 billion to take into account development of successful ventures in the first quarter. However, our strong balance sheet will be maintained."

HIGHLIGHTS OF THE FIRST QUARTER

- Increase of 83% in cash flow to $629 million ($5.15 per common share) from $343 million ($3.06 per common share) in the first quarter of 2000.
- Increase of 86% in earnings to $265 million ($2.17 per common share) from $142 million ($1.27 per common share) in the first quarter of 2000.
- Natural gas sales of 851 million cubic feet per day, an increase from the fourth quarter of 2000 and a 16% increase over the first quarter of 2000.
- Oil and liquids sales of 206,000 barrels per day, an increase from the fourth quarter of 2000 and a 48% increase from the first quarter of 2000.
- Cash flow per barrel of oil equivalent increased to $20.21 from $14.45 in the first quarter of 2000 and $17.68 in the fourth quarter of 2000.
- After-tax return on common equity of 33%.
- Reduction in annualized debt to cash flow ratio to 1 times.
- First quarter capital expenditure program of $578 million in North America with a further $56 million expended on development of UK and international properties.
- Drilling of 164 natural gas wells in Canada, including development programs at Helmet and Dahl in British Columbia.
- Interpretation of 3D seismic shot on lands at Ladyfern, British Columbia, where the Company holds 100% interest in 30,000 acres of land, identifies several high potential natural gas locations in the Slave Point formation. Drilling is currently underway.
- Completion of 500 kilometers of natural gas pipelines and gathering systems in our three Canadian natural gas producing areas.
- Completion of facilities for the production, commencing April 7, 2001, of 8,000 net barrels per day of light oil from the Kyle field in the North Sea.
- Re-commencement of production from the Banff field in the North Sea on March 29, 2001 of 6,000 net barrels per day of light oil after repairs to the FPSO.
- Drilled and tested at a rate of 6,700 net barrels per day a deep water well offshore Côte d'Ivoire.
- Acquired further interests in the high netback Pelican Lake oil field to control 80% of the known oil reservoir.
- Repurchased 703,100 common shares under its Normal Course Issuer Bid.
- Paid initial common share dividend of $0.10 per share.

OPERATIONS REVIEW

Natural gas production increased to an average of 851 million cubic feet per day in the first quarter of 2001. This is an increase of 2% from the last quarter of 2000 and a 16% increase over production of natural gas in the first quarter of 2000. Oil production increased 48% from the first quarter of 2000 to 205,588 barrels per day. Light and medium oil comprises 30% of the Company's total barrel of oil equivalent production with primary heavy oil production accounting for 16% of total barrel of oil equivalent production. Production of oil recovered using thermal production processes accounted for 13% of Canadian Natural's total barrel of oil equivalent production base. The Company's production composition was as follows:

	Q1 2001		Q4 2000		Q1 2000	
(thousands)	**boe/d**	**%**	boe/d	%	boe/d	%
Natural gas	**141.8**	**41**	138.6	41	122.3	47
Light and medium oil	**105.0**	**30**	106.8	31	56.7	22
Primary heavy oil	**56.9**	**16**	59.6	17	47.4	18
Thermal heavy oil	**43.7**	**13**	36.4	11	34.7	13
	347.4		341.4		261.1	

Canadian Natural's first quarter 2001 drilling program in Canada was adjusted from the Company's original 2001 budget to reflect changing economies. The Company drilled one-half the number of planned heavy oil wells and increased by 30 wells the number of natural gas wells drilled. The total success rate for the Company's drilling program in the first quarter was 96%.

At Helmet in Northeastern British Columbia, Canadian Natural drilled a total of 11 net wells in a development program covering a large area of British Columbia adjacent to the border with the Northwest Territories. This drilling program resulted in wells with initial production rates of 20 million cubic feet of natural gas per day being tied in and placed on production by the end of the first quarter.

Other positive drilling results in Canadian Natural's Northeastern British Columbia/Northwestern Alberta core region were realized at Velma, Dahl and Peejay with the drilling of 16 net successful natural gas wells. These wells were tied into production facilities and added 10 million cubic feet of natural gas production. Another 32 natural gas wells were drilled in other fields in this core region, while in Canadian Natural's other natural gas core regions in North Central Alberta and South Central Alberta, a total of 105 natural gas wells were drilled, completed and placed on production. These successful drilling programs pushed the Company's natural gas production capability to over 900 million cubic feet per day.

An additional 31 oil wells were drilled at Pelican Lake, Alberta. The Company augmented this drilling program by acquiring additional producing and non-producing land interests in the area. Upon completion of this acquisition in the first quarter, Canadian Natural now controls over 80% of the oil pool at Pelican Lake. Oil produced from Pelican Lake continued to achieve a high netback of $12.29 per barrel in the first quarter of the year due to the low operating costs incurred on the property. Significant natural gas is also produced in association with the oil and the gas is sold through Company operated gathering and processing facilities.

Further stratographic test wells were drilled on Canadian Natural's Horizon (formerly known as Mic Mac) oil sands project lands located north of Fort McMurray. This drilling program confirmed mineable areas thicker and closer to the surface than had first been anticipated. Additional delineation drilling will take place on these leases next winter.

Internationally, Canadian Natural operated, with a 61% equity interest, the Baobab 1X well in deep water offshore Côte d'Ivoire in West Africa. The well discovered oil in lower Cretaceous sandstones and, with two drill stem tests on selected intervals tested in excess of 6,700 barrels of oil per day. This well is eight kilometres south of the Canadian Natural operated Espoir field, which is undergoing development drilling and production facility construction for a production start in the first quarter of 2002.

In the first quarter of this year Canadian Natural increased its ownership from 50% to 100% in the Echo pipeline system which connects from several of Canadian Natural's heavy oil producing areas in Eastern Alberta to terminal and sales pipeline facilities at Hardisty, Alberta. This pipeline can be extended and will provide Canadian Natural with a strategic transportation outlet for its productive lands in its heavy oil producing fields in Eastern Alberta.

Activity by Core Region

	Undeveloped Land (thousands of net acres)	Q1 Drilling Activity (net wells)
Northeastern British Columbia/Northwestern Alberta	**1,429**	**62.6**
North Central Alberta	**2,382**	**89.0**
Alberta Oil Sands	**233**	**197.0**
Eastern Alberta/Western Saskatchewan	**1,065**	**109.6**
South Central Alberta	**542**	**67.0**
Williston Basin	**341**	**4.0**
United Kingdom North Sea	**202**	**0.9**
Offshore West Africa	**1,328**	**0.6**

Drilling Program

	Three Months Ended March 31			
	2001		2000	
	Gross	**Net**	Gross	Net
Oil	**123**	**108.5**	104	96.2
Natural gas	**199**	**163.5**	153	125.6
Injection/strat tests	**241**	**239.8**	26	26.0
Dry	**22**	**19.8**	24	22.1
Total	**585**	**531.6**	307	269.9
Success rate		**96%**		92%

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") of financial conditions and results of operations should be read in conjunction with the unaudited interim consolidated financial statements for the three months ended March 31, 2001 and the MD&A and audited consolidated financial statements for the year ended December 31, 2000.

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.

Financial Highlights

	Three Months Ended		
	March 31	December 31	March 31
($ millions, except per share amounts)	**2001**	2000	2000
Gross revenue	**$ 1,121**	$ 1,031	$ 550
Cash flow attributable to common shareholders (1)	**$ 629**	$ 553	$ 343
Per share – basic	**$ 5.15**	$ 4.56	$ 3.06
– diluted	**$ 4.94**	$ 4.39	$ 3.01
Net earnings attributable to common shareholders (1)	**$ 265**	$ 223	$ 142
Per share – basic	**$ 2.17**	$ 1.84	$ 1.27
– diluted	**$ 2.08**	$ 1.77	$ 1.25
Capital expenditures, net of dispositions	**$ 635**	$ 195	$ 469

(1) After dividend on preferred securities

Operating Highlights

	Three Months Ended		
	March 31 2001	December 31 2000	March 31 2000
Oil and natural gas liquids			
Daily production (barrels)	**205,588**	202,732	138,735
Sales price	**$ 22.06**	$ 25.37	$ 29.45
Royalties	**2.36**	2.83	3.06
Operating costs	**7.88**	7.60	5.01
Netback per barrel	**$ 11.82**	$ 14.94	$ 21.38
Natural gas			
Daily production (million cubic feet)	**850.8**	831.8	734.0
Sales price	**$ 9.30**	$ 7.28	$ 2.67
Royalties	**2.40**	1.83	0.52
Operating costs	**0.50**	0.47	0.41
Netback per thousand cubic feet	**$ 6.40**	$ 4.98	$ 1.74
Barrel of oil equivalent (6:1)			
Daily production	**347,382**	341,369	261,070
Sales price	**$ 35.85**	$ 32.82	$ 23.16
Royalties	**7.27**	6.13	3.10
Operating costs	**5.89**	5.66	3.81
Netback per boe	**$ 22.69**	$ 21.03	$ 16.25

Cash flow and net earnings in the first quarter of 2001 increased to record levels as a result of increased production volumes and higher realized natural gas prices.

Daily Production

	Three Months Ended		
	March 31 2001	December 31 2000	March 31 2000
Oil and liquids (bbls/day)			
North America	**176,102**	167,464	138,735
North Sea	**27,210**	30,721	–
Other International	**2,276**	4,547	–
Total	**205,588**	202,732	138,735
Natural gas (mmcf/day)			
North America	**850.8**	831.5	734.0

The acquisition of Ranger Oil Limited (“Ranger”) in the third quarter of 2000 added primarily natural gas and heavy oil production in Canada and established a base of light oil production in the UK and Offshore West Africa. Natural gas production also increased as a result of an active capital expenditure program over the winter season which targeted natural gas development opportunities in response to increased market demand for natural gas and the resultant upward movement in natural gas prices.

Product Prices

	Three Months Ended		
	March 31 2001	December 31 2000	March 31 2000
Oil and liquids (per bbl)			
North America	**$ 18.88**	$ 21.61	$ 29.45
North Sea	**$ 41.04**	$ 43.86	$ –
Other International	**$ 40.58**	$ 39.10	$ –
Company average	**$ 22.06**	$ 25.37	$ 29.45
Natural gas (per mcf)			
North America	**$ 9.30**	$ 7.28	$ 2.67

The North American realized oil price decreased from first quarter 2000 primarily as a result of an increase in heavy oil differentials, averaging US $12.99 per barrel in the first quarter of 2001 compared to US $5.49 per barrel in the comparable quarter of 2000. The differential has increased to historically high levels since the third quarter of 2000 as refiners utilize all available refinery capacity to process light crudes to replenish gasoline inventories. The North American natural gas price increased substantially in the first quarter of 2001 due to demand and supply conditions. Arrangements entered into by the Company to fix a portion of the pricing on its sale portfolio resulted in a reduction to realized prices. The price realized from the sale of oil was reduced by $0.08 in the quarter ended March 31, 2001 ($2.13 and $1.75 reduction, respectively, in the quarters ended December 31, 2000 and March 31, 2000) while the price realized from the sale of its natural gas was reduced by $0.80 in the first quarter of 2001 ($0.63 and $0.11 reduction, respectively, in the quarters ended December 31, 2000 and March 31, 2000).

Royalties

	Three Months Ended		
	March 31 2001	December 31 2000	March 31 2000
Oil and liquids ($/bbl)			
North America	**$ 2.30**	$ 2.90	$ 3.06
North Sea	**$ 2.86**	$ 2.89	$ –
Natural gas ($/mcf)			
North America	**$ 2.40**	$ 1.83	$ 0.52
Company average ($/boe)	**$ 7.27**	$ 6.13	$ 3.10

Oil and liquids royalties declined in North America in response to declining prices and increased production of heavy and thermal oil which qualifies for a lower royalty structure. Natural gas royalties increased due to the significant increase in natural gas prices.

Production Expenses

	Three Months Ended		
	March 31 2001	December 31 2000	March 31 2000
Oil and liquids ($/bbl)			
North America	**$ 7.27**	$ 7.21	$ 5.01
North Sea	**$ 9.22**	$ 8.09	$ –
Other International	**$ 38.80**	$ 18.53	$ –
Natural gas ($/mcf)			
North America	**$ 0.50**	$ 0.47	$ 0.41
Company average ($/boe)	**$ 5.89**	$ 5.66	$ 3.81

The increase in North America oil and natural gas production expense is attributable to higher associated costs for fuel, power and processing. The cost of processing thermal heavy oil in Canada was also affected by the increased cost of natural gas used to produce steam to heat the oil formation. The Kiame field in Angola continues to experience high operating costs per barrel due to the fixed costs associated with the floating production storage and offtake vessel and reduced production in the first quarter of 2001.

Depletion, Depreciation and Amortization

	Three Months Ended		
	March 31 2001	December 31 2000	March 31 2000
Company average ($/boe)	**$ 6.65**	$ 6.43	$ 5.28

Depletion costs increased due to higher overall costs associated with the Company's increased emphasis on natural gas drilling and completion in Canada.

Administration Expense

	Three Months Ended		
	March 31 2001	December 31 2000	March 31 2000
Gross costs ($ millions)	**$ 22.7**	$ 21.7	$ 13.3
Per boe	**$ 0.73**	$ 0.69	$ 0.56
Net costs ($ millions)	**$ 8.3**	$ 10.3	$ 5.1
Per boe	**$ 0.26**	$ 0.33	$ 0.21

The Company's administration costs have increased from the first quarter of 2000 as a result of its more diversified asset base. Net costs are reflective of higher activity levels in the first quarter of the years which results in a larger recovery of administration costs.

Interest Expense

	Three Months Ended		
	March 31 2001	December 31 2000	March 31 2000
Interest expense ($ millions)	**$ 38.5**	$ 46.3	$ 32.0
Per boe	**$ 1.23**	$ 1.47	$ 1.35
Average interest rate	**6.25%**	6.61%	5.80%

Interest expense increased from first quarter of 2000 due to higher outstanding debt levels and a higher fixed rate component, both primarily associated with the Ranger acquisition. Interest expense per boe decreased due to higher production levels. Interest expense declined from the fourth quarter of 2000 due to a reduction in average outstanding indebtedness and lower borrowing costs.

Taxes

	Three Months Ended		
($ millions)	**March 31 2001**	December 31 2000	March 31 2000
Taxes other than income tax			
Current	**$ 17.1**	$ 29.9	$ 3.0
Deferred	**$ 0.8**	$ (3.6)	$ –
Current income tax			
North Sea	**$ 9.8**	$ 14.4	$ –
Large corporation tax	**$ 3.9**	$ 4.4	$ 2.7
Future income tax	**$ 155.2**	$ 130.1	$ 75.4
Effective tax rate	**38.8%**	39.9%	35.4%

Current and deferred taxes other than income tax relate primarily to UK Petroleum Revenue Tax which is charged on applicable fields at a rate of 50% of net operating income after certain deductions.

Future income tax expense increased as a result of increased earnings before taxes. Future income taxes payable and property, plant and equipment have been increased by $85.6 million to provide for the acquisition of non-tax base assets in North America in the first quarter of 2001.

Liquidity and Capital Resources

($ millions)	Three Months Ended March 31 2001	December 31 2000	March 31 2000
Working capital deficit	**$ 230.7**	$ 77.3	$ 40.0
Long-term debt	**$ 2,377.9**	$ 2,454.5	$ 2,191.1
Shareholders' equity			
Preferred securities	**$ 118.3**	$ 118.3	$ –
Share capital and contributed surplus	**$ 1,691.5**	$ 1,692.6	$ 1,283.9
Retained earnings	**$ 1,638.8**	$ 1,406.0	$ 766.1
Debt to cash flow (1) (2)	**1.1x**	1.3x	2.3x
Debt to equity (1)	**42.8%**	45.4%	51.7%
Debt to market capitalization (1)	**29.9%**	32.6%	33.7%
Return on average common shareholders' equity (2)	**33.2%**	32.4%	19.9%
Return on average capital employed (2)	**19.2%**	18.1%	11.7%

(1) Includes preferred securities as debt equivalents

(2) Based on trailing 12 months activity

Capital Expenditures

($ millions)	Three Months Ended March 31 2001	December 31 2000	March 31 2000
Expenditures on property, plant and equipment			
Net property acquisitions (dispositions)	**$ 190.7**	$ (92.7)	$ 185.9
Land acquisition and retention	**27.7**	45.7	8.9
Seismic evaluations	**37.0**	18.1	11.1
Well drilling, completion and equipping	**237.5**	125.8	159.0
Pipeline and production facilities	**111.4**	98.2	102.3
Total net reserve replacement expenditures	**$ 604.3**	$ 195.1	$ 467.2
Midstream	**28.9**	–	–
Head office equipment	**1.5**	0.3	1.3
Total capital expenditures	**$ 634.7**	$ 195.4	$ 468.5
North America	**$ 578.1**	$ 144.5	$ 468.5
North Sea	**14.8**	29.6	–
Other International	**41.8**	21.3	–
	$ 634.7	$ 195.4	$ 468.5

North America capital expenditures include the acquisition of the remaining 50% interest in Echo Pipelines Ltd. as well as the acquisition of properties in the Pelican Lake area. The Company also drilled 156 stratographic wells relating to Project Horizon in the first quarter of 2001. Internationally, expenditures have been incurred on the development of the Espoir field and exploration of the Baobab field, both located offshore West Africa.

Netback Analysis

	Three Months Ended March 31		
	2001	2000	% Change
Barrel of oil equivalent (6:1)			
Daily production	347,382	261,070	+33
Sales price	$ 35.85	$ 23.16	+55
Royalties	7.27	3.10	+135
Operating costs	5.89	3.81	+55
Netback	22.69	16.25	+40
Administration	0.26	0.21	+24
Interest	1.23	1.35	–9
Taxes other than income tax	0.55	0.13	+323
Current income tax (North Sea)	0.32	–	–
Current income tax (Large Corporation Tax)	0.12	0.11	+9
Cash flow	$ 20.21	$ 14.45	+40

	Three Months Ended March 31, 2001			
	North America	North Sea	Other International	Total
Oil and natural gas liquids				
Daily production (barrels)	176,102	27,210	2,276	205,588
Sales price	$ 18.88	$ 41.04	$ 40.58	$ 22.06
Royalties	2.30	2.86	–	2.36
Operating costs	7.27	9.22	38.80	7.88
Netback per barrel	$ 9.31	$ 28.96	$ 1.78	$ 11.82
Natural gas				
Daily production (million cubic feet)	850.8	–	–	850.8
Sales price	$ 9.30	$ –	$ –	$ 9.30
Royalties	2.40	–	–	2.40
Operating costs	0.50	–	–	0.50
Netback per thousand cubic feet	$ 6.40	$ –	$ –	$ 6.40
Barrel of oil equivalent (6:1)				
Daily production	317,896	27,210	2,276	347,382
Sales price	$ 35.36	$ 41.04	$ 40.58	$ 35.85
Royalties	7.70	2.86	–	7.27
Operating costs	5.37	9.22	38.80	5.89
Netback per boe	$ 22.29	$ 28.96	$ 1.78	$ 22.69

CONSOLIDATED BALANCE SHEET

(millions of Canadian dollars) (unaudited)		**March 31 2001**		December 31 2000
ASSETS				
Current assets				
Cash	**$**	**30.7**	$	28.0
Accounts receivable and prepaid expenses		**531.4**		550.1
Inventories		**34.5**		33.9
		596.6		612.0
Property, plant and equipment, net		**7,659.8**		7,141.5
Deferred charges		**57.8**		22.1
	$	**8,314.2**	$	7,775.6
LIABILITIES				
Current liabilities				
Accounts payable	**$**	**375.7**	$	301.1
Accrued liabilities		**432.8**		371.7
Current portion of long-term debt (note 3)		**18.8**		16.5
		827.3		689.3
Long-term debt (note 3)		**2,377.9**		2,454.5
Future site restoration		**176.4**		170.5
Future income tax		**1,484.0**		1,244.4
		4,865.6		4,558.7
SHAREHOLDERS' EQUITY				
Preferred securities		**118.3**		118.3
Share capital and contributed surplus (note 4)		**1,691.5**		1,692.6
Retained earnings		**1,638.8**		1,406.0
		3,448.6		3,216.9
	$	**8,314.2**	$	7,775.6

Signed on behalf of the Board

Allan P. Markin
Director

N. Murray Edwards
Director

CONSOLIDATED STATEMENT OF EARNINGS

(millions of Canadian dollars, except per share amounts) (unaudited)	Three Months Ended March 31 2001	2000
REVENUE		
Oil and natural gas	**$ 1,120.9**	$ 550.4
Less: royalties	**227.2**	73.8
	893.7	476.6
EXPENSES		
Production	**184.3**	90.6
Depletion, depreciation and amortization	**208.1**	125.4
Administration	**8.3**	5.1
Interest	**38.5**	32.0
Unrealized foreign exchange loss	**1.8**	0.1
	441.0	253.2
EARNINGS BEFORE TAXES	**452.7**	223.4
Taxes other than income tax	**17.9**	3.0
Current income tax	**13.7**	2.7
Future income tax	**155.2**	75.4
NET EARNINGS	**265.9**	142.3
Dividend on preferred securities (net of tax)	**(1.4)**	–
NET EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS	**$ 264.5**	$ 142.3
PER COMMON SHARE (note 2)		
Basic	**$ 2.17**	$ 1.27
Diluted	**$ 2.08**	$ 1.25
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (thousands) (note 2)		
Basic	**122,100**	112,115
Diluted	**127,921**	114,085

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

(millions of Canadian dollars) (unaudited)	Three Months Ended March 31 2001	2000
BALANCE – BEGINNING OF PERIOD	**$ 1,406.0**	$ 623.8
Net earnings	**265.9**	142.3
Dividend on common shares (note 4)	**(12.2)**	–
Dividend on preferred securities (net of tax)	**(1.4)**	–
Repurchase of common shares (note 4)	**(19.5)**	–
BALANCE – END OF PERIOD	**$ 1,638.8**	$ 766.1

CONSOLIDATED STATEMENT OF CASH FLOWS

(millions of Canadian dollars, except per share amounts) (unaudited)	Three Months Ended March 31 2001	2000
OPERATING ACTIVITIES		
Net earnings	**$ 265.9**	$ 142.3
Non-cash items		
Depletion, depreciation and amortization	**208.1**	125.4
Deferred petroleum revenue tax	**0.8**	–
Future income tax	**155.2**	75.4
Unrealized foreign exchange loss	**1.8**	0.1
Cash flow provided from operating activities	**631.8**	343.2
Net change in non-cash working capital balances related to operating activities	**32.0**	(9.9)
	663.8	333.3
FINANCING ACTIVITIES		
Increase (decrease) in long-term debt	**(112.9)**	33.2
Issue of capital stock	**10.6**	15.6
Repurchase of common shares	**(31.2)**	–
Dividend on preferred securities	**(2.5)**	–
Net change in non-cash working capital balances related to financing activities	**5.2**	–
	(130.8)	48.8
INVESTING ACTIVITIES		
Expenditures on property, plant and equipment	**(635.9)**	(468.8)
Net proceeds on sale of property, plant and equipment	**1.2**	0.2
Net change in non-cash working capital balances related to investing activities	**104.4**	86.6
	(530.3)	(382.0)
INCREASE IN CASH	**2.7**	0.1
CASH – BEGINNING OF PERIOD	**28.0**	0.1
CASH – END OF PERIOD	**$ 30.7**	$ 0.2
Cash flow per share from operations attributable to common shareholders (note 2)		
Basic	**$ 5.15**	$ 3.06
Diluted	**$ 4.94**	$ 3.01
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION		
Interest paid	**$ 34.3**	$ 29.9
Taxes paid	**$ 52.7**	$ 7.1

(in millions of Canadian dollars, unless otherwise stated)

1. ACCOUNTING POLICIES

The interim consolidated financial statements of Canadian Natural Resources Limited (the "Company") have been prepared following the same accounting policies and methods of computation as the consolidated financial statements of the Company as at December 31, 2000, except as described in note 2. The interim consolidated financial statements contain disclosures which are supplemental to the Company's annual consolidated financial statements. Certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. The interim consolidated financial statements should be read in conjunction with the Company's consolidated financial statements and notes thereto for the year ended December 31, 2000.

2. CHANGE IN ACCOUNTING POLICY

Effective January 1, 2001, the Company adopted the Canadian Institute of Chartered Accountants' new accounting standard with respect to the calculation and disclosure of per share amounts. Under the new standard, the treasury stock method of calculating per share amounts is used whereby any proceeds from the exercise of stock options or other dilutive instruments are assumed to be used to purchase common shares at the average market price during the period.

In computing diluted per share amounts, 5.8 million common shares were added to the weighted average number of common shares for the quarter ended March 31, 2001 (March 31, 2000 – 2.0 million common shares) for the dilutive effect of employee stock options, warrants and preferred securities. Dividends on preferred securities were added back to net earnings and cash flow attributable to common shareholders in computing diluted per share amounts.

The new standard has been applied retroactively and prior periods have been restated. The new standard has no effect on basic per share amounts but does affect diluted per share amounts. Had the new standard not been adopted, fully diluted net earnings and cash flow attributable to common shareholders per share for the three months ended March 31, 2001 would have been $2.17 and $5.15 respectively.

3. LONG-TERM DEBT

	March 31 2001	December 31 2000
Bank credit facilities		
Canadian dollar debt	$ 1,321.7	$ 1,445.7
US dollar debt (US$ 296 million)	466.9	444.0
Limited recourse loan	22.1	11.8
Medium term notes	250.0	250.0
Senior unsecured notes (US$ 213 million)	336.0	319.5
	$ 2,396.7	$ 2,471.0
Amount due within one year	18.8	16.5
	$ 2,377.9	$ 2,454.5

Bank credit facilities

The Company has unsecured bank credit facilities of approximately $2,360 million comprised of a $100 million operating demand facility, two revolving credit and term loan facilities totaling $2,025 million and a revolving credit facility of US$ 150 million. During the three months ended March 31, 2001, the Company repaid and cancelled a $450 million credit facility.

4. SHARE CAPITAL AND CONTRIBUTED SURPLUS

	March 31 2001	December 31 2000
Common shares	$ 1,688.9	$ 1,688.0
Warrants	2.6	2.7
Contributed surplus	–	1.9
	$ 1,691.5	$ 1,692.6

Issued

	March 31, 2001	
	Number of shares	Amount
Common shares		
Balance – January 1, 2001	122,279,000	$ 1,688.0
Exercise of stock options	366,573	10.5
Exercise of warrants	5,066	0.2
Repurchase of shares under Normal Course Issuer Bid	(703,100)	(9.8)
Balance – March 31, 2001	121,947,539	$ 1,688.9
Warrants		
Balance – January 1, 2001	464,510	$ 2.7
Exercised during the period	(5,066)	(0.1)
Balance – March 31, 2001	459,444	$ 2.6

Stock options

	March 31, 2001	
	Share Options	Weighted Average Exercise Price
Outstanding – January 1, 2001	10,664,243	$ 32.78
Granted	2,800,000	40.04
Exercised	(366,573)	28.72
Forfeited	(330,344)	38.74
Outstanding – March 31, 2001	12,767,326	$ 34.33
Exercisable – March 31, 2001	2,717,835	$ 30.21

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 five percent of the outstanding common shares of the Company on the date of announcement during the 12 month period beginning January 22, 2001 and ending January 21, 2002. As at March 31, 2001, the Company had purchased 703,100 common shares for a total cost of $31.2 million. Subsequent to March 31, 2001, the Company has purchased an additional 1,203,700 common shares for a total cost of $54.8 million.

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. The initial payment was made on April 1, 2001, to shareholders of record on March 19, 2001.

5. SEGMENTED INFORMATION

		Three Months Ended March 31		
		2001		2000
Revenue				
North America	$	**1,012.1**	$	550.4
North Sea		**100.5**		–
Other International		**8.3**		–
		1,120.9		550.4
Net Earnings				
North America	$	**246.5**	$	142.3
North Sea		**24.2**		–
Other International		**(4.8)**		–
		265.9		142.3
Dividend on preferred securities (net of tax)		**(1.4)**		–
Net Earnings Attributable to Common Shareholders	$	**264.5**	$	142.3

CONSOLIDATED FINANCIAL 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 February 22, 1999 as supplemented and amended. 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, 2001.

Interest coverage (times)		
Net earnings	**10.3**	**(1)**
Cash flow	**14.7**	**(2)**

Asset coverage ratios as at March 31, 2001.

Asset coverage (times)		
Before deduction of future income taxes and deferred credits	**3.1**	**(3)**
After deduction of future income taxes and deferred credits	**2.4**	**(4)**

(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.

(3) Total current and capital assets minus current liabilities; divided by long-term debt.

(4) Total current and capital assets minus current liabilities and long-term liabilities excluding long-term debt; divided by long-term debt.

2001 SECOND QUARTER RESULTS

2001 second quarter results are scheduled for release Wednesday, August 8, 2001. A conference call will be held at 9:00 a.m. Mountain Daylight Time, 11:00 a.m. Eastern Daylight Time.

CORPORATE PROFILE

Canadian Natural Resources Limited is a senior independent oil and natural gas exploration, development and production company based in Calgary, Alberta. The Company's operations are focused in Western Canada, the North Sea and Offshore West Africa.

Canadian Natural's profitable growth has been based on the fundamental principles of effective cost control, manageable bank debt and a defined operating strategy. The strategy follows a balanced approach to exploration and acquisitions, combined with a focus on cost effective exploitation in defined core areas. In addition, Canadian Natural understands production area and production limitations and maintains balance sheet discipline. Adhering to this strategy has resulted in Canadian Natural building a strong asset base capable of balanced production of heavy oil, light oil and natural gas.

CORPORATE INFORMATION

Officers

Allan P. Markin
Chairman

John G. Langille
President

Brian L. Illing
Senior Vice-President, Exploration

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

Steve W. Laut
Senior Vice-President, Operations

Tim S. McKay
Senior Vice-President, Production

Réal M. Cusson
Vice-President, Marketing

Philip A. Dimmock
Vice-President, UK and International Ranger Oil (UK) Limited

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

Douglas A. Proll
Vice-President, Finance

Lyle G. Stevens
Vice-President, Exploitation

Board of Directors

N. Murray Edwards

James T. Grenon

John G. Langille

Keith A.J. MacPhail

Allan P. Markin

James S. Palmer, C.M., Q.C.

Eldon R. Smith, M.D.

Registrar and Transfer Agent

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Stock Listing

The Toronto Stock Exchange
Symbol: CNQ

New York Stock Exchange
Symbol: CED

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