CANADIAN NATURAL RESOURCES LIMITED

Press Release

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2001 SECOND QUARTER RESULTS
CALGARY, ALBERTA – AUGUST 8, 2001 – FOR IMMEDIATE RELEASE

CANADIAN NATURAL ANNOUNCES RECORD SECOND QUARTER AND FIRST HALF 2001 RESULTS; QUARTERLY PRODUCTION IN EXCESS OF 360,000 BOED

"Our second quarter results reflect the strength of Canadian Natural's focused programs in exploration, exploitation and development", comments Mr. Allan Markin, Chairman. "We have shown significant growth in our natural gas production with second quarter production averaging 885 million cubic feet per day. This natural gas production growth will continue into the third quarter as our first well, c-82-G, at Ladyfern in British Columbia commenced production in late June and has been producing at a restricted rate of 55 million cubic feet per day. During the second quarter, netbacks on our heavy oil operations also improved as the heavy/light oil differential and the cost of condensate began to decline to historical levels. Lower natural gas prices also contributed to a reduction in operating costs on our thermal heavy oil operations. We expect the netbacks from our heavy oil operations will continue to improve through the third quarter of this year. Finally, we achieved strong production levels with daily production of over 360,000 barrels of oil equivalent, an increase of 33% over the same period in 2000."

HIGHLIGHTS OF THE SECOND QUARTER

- Cash flow increased 32% to $528 million ($4.36 per common share) from $400 million ($3.55 per common share) for the second quarter of 2000. First half cash flow of over $1.1 billion ($9.51 per common share).
- Earnings up 41 percent to $249 million ($2.06 per common share) from $176 million ($1.55 per common share) in the second quarter of 2000. First half earnings of over half a billion dollars ($4.23 per common share).
- Oil and liquids sales of 215 thousand barrels per day, an increase from the first quarter of this year and a 48% increase from the second quarter of 2000.
- Natural gas sales of 885 million cubic feet per day, an increase from the first quarter of this year and a 15% increase from the second quarter of 2000.
- Cash flow per barrel of oil equivalent remaining constant with the second quarter of 2000.
- A 32% after tax return on average common shareholders' equity.
- Quarterly capital expenditures of $368 million were less than cash flow of $528 million, with $255 million spent on North America properties and $113 million spent in the UK and other international areas.
- Consolidation of equity interest in the Espoir field of Côte d'Ivoire with the purchase of a further 22.3% interest.
- Completed testing and tie-in of Slave Point well at Ladyfern, British Columbia with production commencing in late June 2001, currently at a facility restricted rate of 55 million cubic feet per day.
- Increased light oil production with the start-up of the Kyle and Banff fields in the North Sea.
- A 7% reduction in oil operating costs per barrel during the quarter.

- Secured first time investment grade rating of “Baa1” on senior unsecured debt from Moody’s Investors Service, Inc.
- In July 2001, filed shelf prospectuses which allow for the issuance of up to US $1 billion of debt securities in the United States and up to Cdn $1 billion of medium term notes in Canada.
- On July 24, 2001, issued an inaugural US debt borrowing of US $400 million of 10 year notes at an interest rate of 6.70%. The notes were priced at the lowest coupon of any Canadian issuer in the oil sector during the past two years.
- Filed a public disclosure document for the Horizon Oil Sands Project, representing the first step of the regulatory approval process.
- Repurchased 1,403,700 common shares under its Normal Course Issuer Bid. A total of 2,537,800 common shares repurchased to date.
- Paid second quarterly dividend of $0.10 per share.

OPERATIONS REVIEW

The year to date results show the strength of the Company’s business approach to diversification among commodities produced, namely natural gas, light and medium oil, primary heavy oil and thermal heavy oil.

Second quarter 2001 natural gas production averaged 885 million cubic feet per day, an increase of 4% from the first quarter of 2001 and a 15% increase from the second quarter of 2000. Second quarter 2001 production did not include a significant contribution from the Ladyfern c-82-G well, which only commenced producing in late June 2001, and did not ramp up to its current restricted production level of 55 million cubic feet per day until early July. Natural gas production accounted for 41% of the Company’s second quarter production.

Production of oil and liquids in the second quarter of 2001 increased 4% from the first quarter of this year and 48% from second quarter 2000 production levels. Light and medium oil production accounts for 32% of the Company’s total production, a 10% increase from the comparative 2000 period. Light oil production increased due to the tie-in of the Canadian Natural operated Kyle field and the re-commencement of production from the Banff field. Both fields are located in the UK sector of the North Sea. Significantly higher netbacks are achieved from these fields as revenues are subject only to UK corporate tax with no encumbrance for royalties or petroleum revenue tax. Thermal heavy oil production has declined to 11% of the Company’s production due to a reduction in the amount of steam injected into the productive formation over the past six months reflecting the higher cost of natural gas required to generate the steam. Primary heavy oil production has decreased from 19% of Canadian Natural’s total production in the second quarter of 2000, to 16% of the Company’s production in the first half of 2001.

The Company’s production composition is as follows:

	Q2 2001		Q1 2001		Q2 2000	
	mboe/d	**%**	mboe/d	%	mboe/d	%
Natural gas	**147.5**	**41**	141.8	41	127.7	47
Light and medium oil	**114.7**	**32**	105.0	30	61.5	22
Primary heavy oil	**58.8**	**16**	56.9	16	52.0	19
Thermal heavy oil	**41.2**	**11**	43.7	13	32.0	12
	362.2		347.4		273.2	

Canadian Natural's second quarter drilling activity focused on medium oil drilling at Pelican Lake, where year round access has been established, and on shallow natural gas areas located in South Central Alberta. The total success rate for Canadian Natural's drilling program remained over 96% in the second quarter of the year.

As noted earlier, Canadian Natural completed the drilling and tie-in of the Ladyfern c-82-G/94-H-1 well with production commencing in late June 2001. The well's production is currently restricted to approximately 55 million cubic feet per day due to availability of production facilities and pipeline connections. In July, testing completed on the recently drilled d-74-G/94-H-1 well in the Ladyfern discovery area indicated that the well is capable of producing in excess of 100 million cubic feet of natural gas per day. In addition, a well at d-86-G/94-H-1 is currently drilling, with drilling and testing expected to be completed in late August 2001. Canadian Natural owns 100% interest in these wells and an additional 30,000 acres of undeveloped land in the area.

The results of wells drilled to date in the Ladyfern area confirm the anomalies identified on seismic. Extensive 2-D and 3-D seismic has been shot and processed over portions of Canadian Natural's land and the Company has identified six additional locations with geophysical characteristics similar to the c-82-G and d-74-G wells. Two drilling rigs are in the area and will drill these locations over the next six to nine months.

Additional pipeline connections are being completed to tie into existing production facilities in British Columbia. It is expected that natural gas production from the Ladyfern area will increase to 100 million cubic feet per day in early September 2001, to 140 million cubic feet in late September of 2001, and to just under 200 million cubic feet by December 2001. Additional volumes will be added in 2002, with increased pipeline takeaway capacity into Alberta expected by April 2002. As a result of the first half's successful natural gas drilling, Canadian Natural increased its 2001 average target level of natural gas production to a range of 875 to 900 million cubic feet per day from its original daily target of 825 to 850 million cubic feet.

Netbacks received for Canadian Natural's heavy and medium oil production began to improve in the second quarter of the year and indications are that this will continue into the third quarter. This improvement is a result of three factors – (1) the discount on price from the WTI benchmark price has declined, (2) the cost of condensate needed for blending has decreased; and (3) operating costs have declined. A comparison of the price received for the Company's heavy and medium oil production is as follows:

	Q1	Q2	Current August 2001 posted prices
WTI benchmark price (US $/bbl)	$ 28.72	$ 27.96	$ 26.35
Differential to LLB blend (US $/bbl)	$ 12.99	$ 11.70	$ 5.50
Condensate benchmark price (US $/bbl)	$ 33.22	$ 33.04	$ 27.35
Canadian Natural Wellhead Price			
Primary heavy oil ($/bbl)	$ 13.96	$ 16.74	$ 28.02
Thermal heavy oil ($/bbl)	$ 11.20	$ 14.53	$ 27.09
Pelican Lake medium oil ($/bbl)	$ 16.78	$ 18.80	$ 29.19

As the cost of natural gas required for the generation of steam has declined in the past several months, the Company has increased the amount of steaming in its thermal heavy oil reservoirs. It is expected the increased production resulting from this additional steaming will be evident by the fourth quarter of this year.

Canadian Natural has also commenced a pilot project to determine the economic feasibility of burning produced heavy oil instead of natural gas to generate steam for its thermal operations. If this test is successful, additional conversion of heat generators would enable Canadian Natural to mitigate the effect of high natural gas prices on its production cost of thermal heavy oil.

In Côte d'Ivoire, Canadian Natural increased its equity interest in the offshore Espoir field to 58.67% with the acquisition of one of its partner's equity interest. Canadian Natural operates the Espoir field and development of the field is proceeding on schedule. The well head tower was installed in April and batch drilling of seven development wells commenced in June with drilling operations presently at the intermediate casing stage. The hydrocarbon processing will be carried out on a Floating Production Storage and Offtake vessel which is being built with scheduled delivery in December 2001. A subsea pipeline for the delivery of associated natural gas to onshore Côte d'Ivoire has already been constructed. The field is scheduled to commence production in early 2002 at a rate of 7,500 barrels of oil per day and 20 million cubic feet of natural gas per day net to Canadian Natural's ownership interest.

In deeper water south of Espoir, Canadian Natural will follow-up its discovery well at Baobab with an appraisal well and two exploration wells on nearby separate structures. A drilling rig has been contracted to commence this drilling in the last quarter of this year and continue into 2002. The Baobab discovery well was drilled by Canadian Natural in the first quarter of 2001 and tested at the rate of 6,700 barrels of oil per day.

During the second quarter, Canadian Natural filed a public disclosure document for its Horizon Oil Sands Project. This is the initial step to proceed with regulatory applications for a long-term oil sands project located 80 kilometres north of Fort McMurray, Alberta. An Environmental Impact Assessment is currently underway for the project, and Canadian Natural has launched a consultation and communications program to ensure that stakeholders have an opportunity to review project plans and provide input throughout all phases of the development. Formal application for project approvals is to be submitted by mid-2002. The proposed project will provide for a potential recovery of more than 5.6 billion barrels of bitumen over an estimated 50-year life span. The project will involve four major components: surface mining and bitumen processing, in-situ operations, an upgrader, and associated infrastructure. Construction is estimated to start in 2004, once necessary regulatory approvals are received. Commissioning and start-up could be as early as 2006 with full production capacity by 2010 of 300,000 barrels per day of bitumen.

ACTIVITY BY CORE REGION	Undeveloped Land As at June 30, 2001 (thousands of net acres)	Drilling Activity Six months ended June 30, 2001 (net wells)
Northeastern British Columbia/Northwestern Alberta	**1,415**	**69**
North Central Alberta	**2,455**	**137**
Alberta Oil Sands	**237**	**197**
Eastern Alberta/Western Saskatchewan	**1,052**	**162**
South Central Alberta	**624**	**170**
Williston Basin	**287**	**4**
United Kingdom North Sea	**262**	**1**
Offshore West Africa	**1,094**	**1**

	SIX MONTHS ENDED JUNE 30			
	2001		2000	
DRILLING ACTIVITY	**Gross**	**Net**	**Gross**	**Net**
Oil	**202**	**182**	204	192
Natural gas	**340**	**287**	292	263
Injection/strat tests	**251**	**249**	26	26
Dry	**28**	**25**	24	22
Total	**821**	**743**	546	503
Success rate		**97%**		96%

FINANCIAL REVIEW

In July 2001, Canadian Natural filed shelf prospectuses in certain provinces of Canada and in 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.

On July 24, 2001, the Company issued US $400 million of ten year, 6.70% notes to purchasers in the United States under the above shelf. Net proceeds from the sale 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.

The purpose for future offerings under the shelf prospectuses is to provide flexibility to the Company’s debt investment base, extend maturities and provide balance in fixed/floating interest rate ratios. In the year to date, Canadian Natural has cancelled three bank lines of credit aggregating $1 billion.

The Company’s unutilized bank lines of credit currently exceed $600 million and are in addition to funds that are available through the Company’s Canadian and US shelf prospectuses. On an annualized basis, the Company’s debt to cash flow ratio is a healthy 1.1 times and the debt to book capitalization ratio is 41%.

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 six months ended June 30, 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.

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2001	MARCH 31 2001	JUNE 30 2000	**JUNE 30 2001**	JUNE 30 2000
FINANCIAL HIGHLIGHTS ($ millions, except per share amounts)					
Gross revenue	**$ 973**	$ 1,121	$ 637	**$ 2,094**	$ 1,188
Cash flow attributable to common shareholders [1]	**$ 528**	$ 629	$ 400	**$ 1,157**	$ 744
Per share – basic	**$ 4.36**	$ 5.15	$ 3.55	**$ 9.51**	$ 6.61
– diluted	**$ 4.18**	$ 4.94	$ 3.44	**$ 9.12**	$ 6.45
Net earnings attributable to common shareholders [1]	**$ 249**	$ 265	$ 176	**$ 514**	$ 318
Per share – basic	**$ 2.06**	$ 2.17	$ 1.55	**$ 4.23**	$ 2.82
– diluted	**$ 1.97**	$ 2.08	$ 1.51	**$ 4.05**	$ 2.76
Capital expenditures, net of dispositions	**$ 368**	$ 635	$ 250	**$ 1,003**	$ 719

[1] *After dividend on preferred securities*

OPERATING HIGHLIGHTS					
Oil and natural gas liquids					
Daily production (bbls)	**214,716**	205,588	145,519	**210,177**	142,127
Sales price	**$ 25.32**	$ 22.06	$ 29.48	**$ 23.73**	$ 29.47
Royalties	**2.42**	2.36	2.91	**2.39**	2.99
Operating costs	**7.32**	7.88	5.10	**7.59**	5.05
Netback per barrel	**$ 15.58**	$ 11.82	$ 21.47	**$ 13.75**	$ 21.43
Natural gas					
Daily production (mmcf)	**884.6**	850.8	766.2	**867.8**	750.1
Sales price	**$ 5.93**	$ 9.30	$ 3.55	**$ 7.57**	$ 3.12
Royalties	**1.47**	2.40	0.81	**1.92**	0.67
Operating costs	**0.50**	0.50	0.42	**0.50**	0.42
Netback per thousand cubic feet	**$ 3.96**	$ 6.40	$ 2.32	**$ 5.15**	$ 2.03
Barrel of oil equivalent (6:1)					
Daily production	**362,154**	347,382	273,220	**354,809**	267,145
Sales price	**$ 29.54**	$ 35.85	$ 25.64	**$ 32.61**	$ 24.43
Royalties	**5.03**	7.27	3.81	**6.12**	3.46
Operating costs	**5.57**	5.89	3.90	**5.73**	3.86
Netback per boe	**$ 18.94**	$ 22.69	$ 17.93	**$ 20.76**	$ 17.11

Cash flow and net earnings for first half 2001 increased over the comparable period in 2000 due to higher natural gas prices and increased production volumes. Second quarter 2001 cash flow and net earnings decreased from first quarter 2001 due mainly to lower natural gas prices.

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2001	MARCH 31 2001	JUNE 30 2000	JUNE 30 2001	JUNE 30 2000
DAILY PRODUCTION					
Oil and liquids (bbls/day)					
North America	**168,938**	176,102	145,519	**172,500**	142,127
North Sea	**41,556**	27,210	-	**34,422**	-
Other International	**4,222**	2,276	-	**3,255**	-
Total	**214,716**	205,588	145,519	**210,177**	142,127
Natural gas (mmcf/day)					
North America	**872.6**	850.8	766.2	**861.8**	750.1
North Sea	**12.0**	-	-	**6.0**	-
Total	**884.6**	850.8	766.2	**867.8**	750.1

Production increased over the first six months of 2000 due to the acquisition of Ranger Oil Limited ("Ranger") completed in the third quarter of 2000 as well as a 2001 capital expenditure program focused on natural gas development opportunities. North America second quarter 2001 oil and liquids production decreased from first quarter 2001 as natural gas prices resulted in a focus on natural gas drilling and a deferral of steam stimulation of thermal heavy oil production. North Sea production volumes increased in second quarter 2001 due to the re-commencement of production from the Banff field and new production from the Kyle field.

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2001	MARCH 31 2001	JUNE 30 2000	JUNE 30 2001	JUNE 30 2000
PRODUCT PRICES					
Oil and liquids ($/bbl)					
North America	**$ 20.59**	$ 18.88	$ 29.48	**$ 19.72**	$ 29.47
North Sea	**$ 43.07**	$ 41.04	$ -	**$ 42.27**	$ -
Other International	**$ 39.75**	$ 40.58	$ -	**$ 40.04**	$ -
Company average	**$ 25.32**	$ 22.06	$ 29.48	**$ 23.73**	$ 29.47
Natural gas ($/mcf)					
North America	**$ 5.99**	$ 9.30	$ 3.55	**$ 7.61**	$ 3.12
North Sea	**$ 1.74**	$ -	$ -	**$ 1.74**	$ -
Company average	**$ 5.93**	$ 9.30	$ 3.55	**$ 7.57**	$ 3.12

First half 2001 North America realized oil price decreased from the comparable period in 2000 primarily as a result of wider heavy oil differentials, averaging US $12.34 per barrel in the first half of 2001 compared to US $5.71 per barrel for first half 2000. Realized oil prices in the second quarter 2001 improved from first quarter 2001 due to the narrowing of the heavy oil differential from US $12.99 to US $11.70. The North America realized natural gas price increased first half 2001 over the comparable period in 2000 due to a tighter supply environment. Realized natural gas prices decreased in second quarter 2001 from first quarter 2001 due to a decrease in market demand for natural gas.

Arrangements entered into by the Company to fix a portion of the price realized from the sale of oil reduced the price by $0.43 per barrel in the quarter ended June 30, 2001 ($0.08 and $1.60 reduction per barrel, respectively, in the quarters ended March 31, 2001 and June 30, 2000). The price realized from the sale of its natural gas was reduced by $0.31 per mcf in the second quarter 2001 ($0.80 and $0.32 reduction per mcf, respectively, in the quarters ended March 31, 2001 and June 30, 2000).

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2001	**MARCH 31 2001**	**JUNE 30 2000**	**JUNE 30 2001**	**JUNE 30 2000**
ROYALTIES					
Oil and liquids ($/bbl)					
North America	**$ 2.51**	$ 2.30	$ 2.91	**$ 2.40**	$ 2.99
North Sea	**$ 2.23**	$ 2.86	$ -	**$ 2.48**	$ -
Other International	**$ 0.65**	$ -	$ -	**$ 0.43**	$ -
Natural gas ($/mcf)					
North America	**$ 1.49**	$ 2.40	$ 0.81	**$ 1.93**	$ 0.67
Company average ($/boe)	**$ 5.03**	$ 7.27	$ 3.81	**$ 6.12**	$ 3.46

Oil and liquids royalties declined in North America from first half 2000 due to lower prices and increased production of heavy and thermal heavy oil which qualifies for a lower royalty structure. Natural gas royalties increased from the first six months of 2000 due to the overall increase in natural gas prices. In the second quarter of 2001, North America oil and liquids royalties have increased over first quarter 2001 due to higher overall realized prices. North Sea royalties declined on a boe basis as a result of increased production from the Banff and Kyle non-royalty paying fields.

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2001	**MARCH 31 2001**	**JUNE 30 2000**	**JUNE 30 2001**	**JUNE 30 2000**
PRODUCTION EXPENSES					
Oil and liquids ($/bbl)					
North America	**$ 6.80**	$ 7.27	$ 5.10	**$ 7.04**	$ 5.05
North Sea	**$ 8.42**	$ 9.22	$ -	**$ 8.73**	$ -
Other International	**$ 17.23**	$ 38.80	$ -	**$ 24.73**	$ -
Natural gas ($/mcf)					
North America	**$ 0.50**	$ 0.50	$ 0.42	**$ 0.50**	$ 0.42
North Sea	**$ 0.61**	$ -	$ -	**$ 0.61**	$ -
Company average ($/boe)	**$ 5.57**	$ 5.89	$ 3.90	**$ 5.73**	$ 3.86

The increase in North America oil and natural gas production expense from first half 2000 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. In second quarter 2001, lower fuel and natural gas costs have resulted in reduced oil and liquids production expense. North Sea production expense per boe decreased primarily due to lower operating costs associated with new production from the Banff and Kyle fields. Other International operating costs are mainly fixed in nature and therefore declined on a per barrel basis due to increased oil production volumes from the Kiame field in Angola.

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2001	MARCH 31 2001	JUNE 30 2000	JUNE 30 2001	JUNE 30 2000
DEPLETION, DEPRECIATION AND AMORTIZATION					
Company average ($/boe)	**$ 6.59**	$ 6.65	$ 5.24	**$ 6.62**	$ 5.26

Depletion costs increased in the first half of 2001 over the comparable period in 2000 due to higher costs associated with the Company's increased emphasis on natural gas drilling and completion in North America and higher depletion costs in the North Sea and Other International segments acquired with Ranger. Per unit depletion costs decreased in second quarter 2001 due to a successful drilling program resulting in additional natural gas reserves.

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2001	MARCH 31 2001	JUNE 30 2000	JUNE 30 2001	JUNE 30 2000
ADMINISTRATION EXPENSE					
Net costs ($ millions)	**$ 7.9**	$ 8.3	$ 6.1	**$ 16.2**	$ 11.2
$/boe	**$ 0.24**	$ 0.26	$ 0.25	**$ 0.25**	$ 0.23

The Company's first half 2001 administration costs have increased from first half 2000 reflecting a more diversified asset base, but remain stable on a per unit basis.

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2001	MARCH 31 2001	JUNE 30 2000	JUNE 30 2001	JUNE 30 2000
INTEREST EXPENSE					
Interest expense ($ millions)	**$ 36.6**	$ 38.5	$ 34.0	**$ 75.1**	$ 65.9
$/boe	**$ 1.11**	$ 1.23	$ 1.36	**$ 1.17**	$ 1.36
Average interest rate	**5.63%**	6.25%	6.26%	**5.94%**	6.03%

Interest expense increased from first half 2000 due to increased debt levels primarily associated with the Ranger acquisition but more importantly, decreased on a boe basis due to increased production levels.

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2001	MARCH 31 2001	JUNE 30 2000	JUNE 30 2001	JUNE 30 2000
TAXES ($ millions)					
Taxes other than income tax					
Current	**$ 21.0**	$ 17.1	$ 2.6	**$ 38.1**	$ 5.6
Deferred	**$ (0.7)**	$ 0.8	$ -	**$ 0.1**	$ -
Current income tax					
North Sea	**$ 25.2**	$ 9.8	$ -	**$ 35.0**	$ -
Large corporation tax	**$ 3.3**	$ 3.9	$ 2.9	**$ 7.2**	$ 5.6
Future income tax	**$ 64.5**	$ 155.2	$ 94.0	**$ 219.7**	$ 169.4
Effective tax rate	**27.0%**	38.8%	35.6%	**33.6%**	35.5%

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 percent of net operating income after certain deductions. North Sea current income tax increased in second quarter 2001 due to increased production and earnings before taxes.

Future income tax expense in the first six months of 2001 increased over the comparable period in 2000 as a result of increased earnings before taxes. Future income tax expense decreased in second quarter 2001 from both first quarter 2001 and second quarter 2000 due to the reduction in the Alberta corporate tax rate effective April 1, 2001. The rate reduction resulted in a one time reduction of $46 million in future income tax liabilities, which was recognized in earnings during the second quarter of 2001.

	JUNE 30 2001	MARCH 31 2001	DECEMBER 31 2000	JUNE 30 2000
LIQUIDITY AND CAPITAL RESOURCES ($ millions)				
Working capital deficit	**$ 113.9**	$ 230.7	$ 77.3	$ 37.4
Long-term debt	**$ 2,369.1**	$ 2,377.9	$ 2,454.5	$ 2,099.4
Shareholders' equity				
Preferred securities	**$ 118.3**	$ 118.3	$ 118.3	$ -
Share capital and contributed surplus	**$ 1,683.9**	$ 1,691.5	$ 1,692.6	$ 1,309.1
Retained earnings	**$ 1,832.1**	$ 1,638.8	$ 1,406.0	$ 941.6
Total shareholders' equity	**$ 3,634.3**	$ 3,448.6	$ 3,216.9	$ 2,250.7
Debt to cash flow (1) (2)	**1.1x**	1.1x	1.3x	1.7x
Debt to book capitalization (1)	**41.4%**	42.8%	45.4%	48.3%
Debt to market capitalization (1)	**30.4%**	29.9%	32.6%	30.1%
After tax return on average common shareholders' equity (2)	**32.1%**	33.2%	32.4%	25.8%
After tax return on average capital employed (2)	**19.2%**	19.2%	18.1%	14.7%

(1) Includes preferred securities as debt equivalents
(2) Based on trailing 12 months activity

	THREE MONTHS ENDED JUNE 30 2001	THREE MONTHS ENDED MARCH 31 2001	THREE MONTHS ENDED JUNE 30 2000	SIX MONTHS ENDED JUNE 30 2001	SIX MONTHS ENDED JUNE 30 2000
CAPITAL EXPENDITURES ($ millions)					
Expenditures on property, plant and equipment					
Net property acquisitions	**$ 55.5**	$ 190.7	$ 68.3	**$ 246.2**	$ 254.2
Land acquisition and retention	**21.5**	27.7	11.4	**49.2**	20.3
Seismic evaluations	**20.2**	37.0	1.1	**57.2**	12.2
Well drilling, completion and equipping	**152.8**	228.4	107.7	**381.2**	266.7
Pipeline and production facilities	**105.0**	111.4	58.5	**216.4**	160.8
Total net reserve replacement expenditures	**$ 355.0**	$ 595.2	$ 247.0	**$ 950.2**	$ 714.2
Midstream	**6.8**	28.9	-	**35.7**	-
Oil sands	**4.8**	9.1	-	**13.9**	-
Head office equipment	**1.4**	1.5	3.5	**2.9**	4.8
Total net capital expenditures	**$ 368.0**	$ 634.7	$ 250.5	**$ 1,002.7**	$ 719.0
By Segment					
North America	**$ 255.4**	$ 578.1	$ 250.5	**$ 833.5**	$ 719.0
North Sea	**16.5**	14.8	-	**31.3**	-
Other International	**96.1**	41.8	-	**137.9**	-
	$ 368.0	$ 634.7	$ 250.5	**$ 1,002.7**	$ 719.0

North America capital expenditures include the development and tie-in of the Ladyfern natural gas field located in British Columbia which began production late June 2001. Internationally, expenditures include the acquisition of an additional working interest in the Espoir field located offshore West Africa as well as the continuing development of the field.

2001 SENSITIVITY ANALYSIS

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

	Cash Flow from Operations ($ millions)	**Cash Flow from Operations** (per share) (basic)	**Net Earnings** ($ millions)	**Net Earnings** (per share) (basic)
Price changes				
Oil – US $1.00/bbl [(1)]	$ 98	$ 0.81	$ 69	$ 0.57
Natural gas– Cdn $1.00/mcf [(2)]	$ 218	$ 1.79	$ 131	$ 1.08
Volume changes				
Oil – 10,000 bbls/day	$ 47	$ 0.39	$ 16	$ 0.13
Natural gas – 10 mmcf/day	$ 15	$ 0.12	$ 7	$ 0.06
Exchange rate change				
$0.01 increase in Cdn $ in relation to US $	$ 46	$ 0.38	$ 30	$ 0.25
Interest rate change				
1%	$ 12	$ 0.10	$ 7	$ 0.06

[(1)] For WTI prices below $26.52 or above $30.44, the oil price sensitivity would be $50 million for cash flow from operations ($0.41 per share) and $38 million for net earnings ($0.31 per share) (see financial statement note 6).
[(2)] North America only

OTHER OPERATING HIGHLIGHTS

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2001	MARCH 31 2001	JUNE 30 2000	JUNE 30 2001	JUNE 30 2000
NETBACK ANALYSIS					
Barrel of oil equivalent (6:1)					
Daily production	**362,154**	347,382	273,220	**354,809**	267,145
Sales price	**$ 29.54**	$ 35.85	$ 25.64	**$ 32.61**	$ 24.43
Royalties	**5.03**	7.27	3.81	**6.12**	3.46
Operating costs	**5.57**	5.89	3.90	**5.73**	3.86
Netback per boe	**18.94**	22.69	17.93	**20.76**	17.11
Administration	**0.24**	0.26	0.25	**0.25**	0.23
Interest	**1.11**	1.23	1.36	**1.17**	1.36
Taxes other than income tax	**0.64**	0.55	0.11	**0.59**	0.12
Current income tax (North Sea)	**0.76**	0.32	-	**0.55**	-
Current income tax (Large Corporation Tax)	**0.10**	0.12	0.11	**0.11**	0.11
Cash flow per boe	**$ 16.09**	$ 20.21	$ 16.10	**$ 18.09**	$ 15.29

	SIX MONTHS ENDED JUNE 30, 2001			
	North America	North Sea	Other International	Total
Oil and natural gas liquids				
Daily production (bbls)	**172,500**	**34,422**	**3,255**	**210,177**
Sales price	**$ 19.72**	**$ 42.27**	**$ 40.04**	**$ 23.73**
Royalties	**2.40**	**2.48**	**0.43**	**2.39**
Operating costs	**7.04**	**8.73**	**24.73**	**7.59**
Netback per bbl	**$ 10.28**	**$ 31.06**	**$ 14.88**	**$ 13.75**
Natural gas				
Daily production (mmcf)	**861.8**	**6.0**	**-**	**867.8**
Sales price	**$ 7.61**	**$ 1.74**	**$ -**	**$ 7.57**
Royalties	**1.93**	**-**	**-**	**1.92**
Operating costs	**0.50**	**0.61**	**-**	**0.50**
Netback per mcf	**$ 5.18**	**$ 1.13**	**$ -**	**$ 5.15**
Barrel of oil equivalent (6:1)				
Daily production	**316,127**	**35,427**	**3,255**	**354,809**
Sales price	**$ 31.54**	**$ 41.50**	**$ 40.04**	**$ 32.61**
Royalties	**6.59**	**2.41**	**0.43**	**6.12**
Operating costs	**5.21**	**8.59**	**24.73**	**5.73**
Netback per boe	**$ 19.74**	**$ 30.50**	**$ 14.88**	**$ 20.76**

CONSOLIDATED BALANCE SHEET (millions of Canadian dollars)

	JUNE 30 2001 (unaudited)	DECEMBER 31 2000 (audited)
Assets		
Current assets		
Cash	**$ 32.0**	$ 28.0
Accounts receivable and prepaid expenses	**549.3**	550.1
Inventories	**31.1**	33.9
	612.4	612.0
Property, plant and equipment, net	**7,820.0**	7,141.5
Deferred charges	**26.0**	22.1
	$ 8,458.4	$ 7,775.6
Liabilities		
Current liabilities		
Accounts payable	**$ 375.4**	$ 301.1
Accrued liabilities	**335.7**	371.7
Current portion of long-term debt (note 3)	**15.2**	16.5
	726.3	689.3
Long-term debt (note 3)	**2,369.1**	2,454.5
Future site restoration	**185.0**	170.5
Future income tax (note 4)	**1,543.7**	1,244.4
	4,824.1	4,558.7
Shareholders' Equity		
Preferred securities	**118.3**	118.3
Share capital and contributed surplus (note 5)	**1,683.9**	1,692.6
Retained earnings	**1,832.1**	1,406.0
	3,634.3	3,216.9
	$ 8,458.4	$ 7,775.6

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

	THREE MONTHS ENDED JUNE 30		SIX MONTHS ENDED JUNE 30	
	2001	**2000**	**2001**	**2000**
Revenue				
Oil and natural gas	**$ 973.5**	$ 637.4	**$ 2,094.4**	$ 1,187.8
Less: royalties	**165.7**	94.6	**392.9**	168.4
	807.8	542.8	**1,701.5**	1,019.4
Expenses				
Production	**183.6**	96.9	**367.9**	187.5
Depletion, depreciation and amortization	**217.1**	130.5	**425.2**	255.9
Administration	**7.9**	6.1	**16.2**	11.2
Interest	**36.6**	33.9	**75.1**	65.9
Unrealized foreign exchange loss (gain)	**(1.6)**	0.4	**0.2**	0.5
	443.6	267.8	**884.6**	521.0
Earnings Before Taxes	**364.2**	275.0	**816.9**	498.4
Taxes other than income tax	**20.3**	2.6	**38.2**	5.6
Current income tax	**28.5**	2.9	**42.2**	5.6
Future income tax (note 4)	**64.5**	94.0	**219.7**	169.4
Net Earnings	**250.9**	175.5	**516.8**	317.8
Dividend on preferred securities, net of tax	**(1.5)**	-	**(2.9)**	-
Net Earnings Attributable to Common Shareholders	**$ 249.4**	$ 175.5	**$ 513.9**	$ 317.8
Per common share (note 2)				
Basic	**$ 2.06**	$ 1.55	**$ 4.23**	$ 2.82
Diluted	**$ 1.97**	$ 1.51	**$ 4.05**	$ 2.76
Weighted average common shares outstanding (thousands)(note 2)				
Basic	**121,148**	112,975	**121,620**	112,545
Diluted	**127,180**	116,552	**127,468**	115,232

CONSOLIDATED STATEMENT OF RETAINED EARNINGS (millions of Canadian dollars)(unaudited)

	SIX MONTHS ENDED JUNE 30	
	2001	**2000**
Balance – Beginning of Period	**$ 1,406.0**	$ 623.8
Net earnings	**516.8**	317.8
Repurchase of common shares (note 5)	**(63.5)**	-
Dividend on common shares (note 5)	**(24.3)**	-
Dividend on preferred securities, net of tax	**(2.9)**	-
Balance – End of Period	**$ 1,832.1**	$ 941.6

CONSOLIDATED STATEMENT OF CASH FLOWS (millions of Canadian dollars, except per share amounts)(unaudited)

	THREE MONTHS ENDED JUNE 30		SIX MONTHS ENDED JUNE 30	
	2001	**2000**	**2001**	**2000**
Operating Activities				
Net earnings	**$ 250.9**	$ 175.5	**$ 516.8**	$ 317.8
Non-cash items				
Depletion, depreciation and amortization	**217.1**	130.5	**425.2**	255.9
Deferred petroleum revenue tax (recovery)	**(0.7)**	-	**0.1**	-
Future income tax	**64.5**	94.0	**219.7**	169.4
Unrealized foreign exchange loss (gain)	**(1.6)**	0.4	**0.2**	0.5
Cash flow provided from operating activities	**530.2**	400.4	**1,162.0**	743.6
Net change in non-cash working capital	**(58.3)**	(15.9)	**(26.3)**	(25.8)
	471.9	384.5	**1,135.7**	717.8
Financing Activities				
Increase (decrease) in long-term debt	**18.0**	(97.6)	**(94.9)**	(64.4)
Issue of capital stock	**11.7**	25.2	**22.3**	40.8
Repurchase of common shares	**(63.4)**	-	**(94.6)**	-
Dividend on common shares	**(12.2)**	-	**(12.2)**	-
Dividend on preferred securities	**(2.6)**	-	**(5.1)**	-
Net change in non-cash working capital	**(6.0)**	1.9	**(0.8)**	1.9
	(54.5)	(70.5)	**(185.3)**	(21.7)
Investing Activities				
Expenditures on property, plant and equipment	**(379.3)**	(255.1)	**(1,015.2)**	(723.9)
Net proceeds on sale of property, plant and equipment	**11.3**	4.7	**12.5**	4.9
Net change in non-cash working capital	**(48.1)**	(63.7)	**56.3**	22.9
	(416.1)	(314.1)	**(946.4)**	(696.1)
Increase (Decrease) in Cash	**1.3**	(0.1)	**4.0**	-
Cash – Beginning of Period	**30.7**	0.2	**28.0**	0.1
Cash – End of Period	**$ 32.0**	$ 0.1	**$ 32.0**	$ 0.1
Cash flow per share from operations attributable to common shareholders (note 2)				
Basic	**$ 4.36**	$ 3.55	**$ 9.51**	$ 6.61
Diluted	**$ 4.18**	$ 3.44	**$ 9.12**	$ 6.45
Supplemental disclosure of cash flow information				
Interest paid	**$ 38.9**	$ 40.4	**$ 73.2**	$ 70.3
Taxes paid	**$ 27.9**	$ 4.9	**$ 80.7**	$ 12.0

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

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, 6.0 million common shares were added to the weighted average number of common shares for the quarter ended June 30, 2001 (June 30, 2000 – 3.6 million common shares) and 5.8 million common shares were added for the six months ended June 30, 2001 (June 30, 2000 – 2.7 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 June 30, 2001 would have been $2.06 and $4.36 respectively, and for the six months ended June 30, 2001, would have been $4.23 and $9.51.

3. LONG-TERM DEBT

	Pro Forma June 30, 2001[1]	June 30 2001	December 31 2000
Bank facilities			
Canadian dollar debt	$ 754.7	**$ 1,361.8**	$ 1,445.7
US dollar debt (US $296 million)	449.2	**449.2**	444.0
US debt securities (US $400 million)	607.1	**-**	-
Limited recourse loan	-	**-**	11.8
Medium term notes	250.0	**250.0**	250.0
Senior unsecured notes (US $213 million)	323.3	**323.3**	319.5
	2,384.3	**2,384.3**	2,471.0
Amount due within one year	15.2	**15.2**	16.5
	$ 2,369.1	**$ 2,369.1**	$ 2,454.5

[1] On July 24, 2001, the Company issued US $400 million debt securities (note 3 (b)). The pro forma disclosure gives effect to the proceeds and their initial use.

Credit Facilities

(a) Bank Facilities

At June 30, 2001, the Company had unsecured bank credit facilities of approximately $2,350 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 six months ended June 30, 2001, the Company had repaid and cancelled a $450 million credit facility as well as the limited recourse loan of $22.1 million.

Concurrent with the issuance of the US debt securities (note 3 (b)), the Company repaid and cancelled an additional $525 million bank facility.

(b) US Debt Securities

In July 2001, the Company authorized a US debt securities program in the aggregate principal amount of up to US $1 billion for issue in the United States. The notes bear interest as determined at the date of issue of the notes.

On July 24, 2001, the Company issued US $400 million of US Debt Securities, maturing July 15, 2011 bearing interest at 6.70%.

(c) Medium Term Notes

In July 2001, the Company authorized a new medium term notes program in the aggregate principal amount of up to $1 billion for issue in Canada. The notes bear interest as determined at the date of issue of the notes. No amounts are currently drawn down under this program.

The Company has $250 million of medium term notes outstanding from a previous medium term note program.

4. INCOME TAXES

The Company's future income tax liability has been reduced by $46 million to reflect a reduction in the Alberta corporate income tax rate effective April 1, 2001. The effect of this reduction has been recognized in the statement of earnings in the current period.

5. SHARE CAPITAL AND CONTRIBUTED SURPLUS

		June 30 2001		**December 31 2000**
Common shares	**$**	**1,681.3**	$	1,688.0
Warrants		**2.6**		2.7
Contributed surplus		**-**		1.9
	$	**1,683.9**	$	1,692.6

Issued

	June 30, 2001		
	Number of shares (000's)		**Amount**
Common shares			
Balance – January 1, 2001	**122,279**	**$**	**1,688.0**
Exercise of stock options	**743**		**22.1**
Exercise of warrants	**13**		**0.5**
Repurchase of shares under Normal Course Issuer Bid	**(2,107)**		**(29.3)**
Balance – June 30, 2001	**120,928**	**$**	**1,681.3**
Warrants			
Balance – January 1, 2001	**465**	**$**	**2.7**
Exercised during the period	**(13)**		**(0.1)**
Balance – June 30, 2001	**452**	**$**	**2.6**

Stock options

	June 30, 2001	
	Share options (000's)	**Weighted average exercise price**
Outstanding – January 1, 2001	**10,664**	**$ 32.78**
Granted	**3,050**	**40.62**
Exercised	**(743)**	**29.71**
Forfeited	**(528)**	**37.20**
Outstanding – June 30, 2001	**12,443**	**$ 34.69**
Exercisable – June 30, 2001	**2,614**	**$ 30.07**

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 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 June 30, 2001, the Company had purchased 2,106,800 common shares for a total cost of $94.6 million. Subsequent to June 30, 2001, the Company has purchased an additional 431,000 common shares for a total cost of $18.7 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 with the second payment made on July 1, 2001 to shareholders of record on June 15, 2001.

6. FINANCIAL INSTRUMENTS

The Company uses certain derivative financial instruments to manage its foreign currency and commodity price exposures. These financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes. At June 30, 2001 the Company had the following hedges outstanding:

	Term	Volume	Price	Index
Crude Oil				
Oil price collars	July 2001 – Dec. 2001	100,000 bbls/day	US $26.52–US $30.44	WTI
Brent differential swaps	July 2001 – Dec. 2001	17,000 bbls/day	US $1.16	Dated Brent/WTI
	Jan. 2002 – Dec. 2002	15,000 bbls/day	US $1.38	Dated Brent/WTI
Natural Gas				
Sumas fixed	July 2001 – Oct. 2002	20,000 mmbtu/day	Cdn $2.85	Sumas
Empress – NYMEX differential swap	July 2001 – Oct. 2006	5,500 mmbtu/day	US $0.73	Empress/NYMEX
NYMEX swaps	July 2001 – Oct. 2001	30,000 mmbtu/day	US $1.75	NYMEX
	July 2001 – Oct. 2006	10,000 mmbtu/day	Cdn $2.66	NYMEX

	Term	Amount ($ millions)	Average Exchange Rate (US $/Cdn $)
Foreign Currency			
Currency fixed	July 2001 – Dec. 2001	US $11.4 /month	1.33
	Jan. 2002 – Oct. 2002	US $0.4 /month	1.37
Currency collar	July 2001 – May 2003	US $4.2 /month	1.43–1.53

7. SEGMENTED INFORMATION

	THREE MONTHS ENDED JUNE 30		SIX MONTHS ENDED JUNE 30	
	2001	**2000**	**2001**	**2000**
Revenue				
North America	**$ 792.6**	$ 637.4	**$ 1,804.7**	$ 1,187.8
North Sea	**165.6**	-	**266.1**	-
Other International	**15.3**	-	**23.6**	-
	973.5	637.4	**2,094.4**	1,187.8
Net Earnings				
North America	**$ 191.3**	$ 175.5	**$ 437.8**	$ 317.8
North Sea	**54.9**	-	**79.1**	-
Other International	**4.7**	-	**(0.1)**	-
	250.9	175.5	**516.8**	317.8
Dividend on preferred securities, net of tax	**(1.5)**	-	**(2.9)**	-
Net Earnings Attributable to Common Shareholders	**$ 249.4**	$ 175.5	**$ 513.9**	$ 317.8
Additions to Property, Plant and Equipment				
North America	**$ 255.4**	$ 250.5	**$ 919.6**	$ 719.0
North Sea	**16.5**	-	**31.3**	-
Other International	**96.1**	-	**137.9**	-
	$ 368.0	$ 250.5	**$ 1,088.8**	$ 719.0

Property, plant and equipment and future income taxes payable have been increased by $86.1 million to provide for the tax effect of the acquisition of non-tax base assets in North America in first half 2001.

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 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 June 30, 2001.

Interest coverage (times)	
Net earnings	**10.2** [(1)]
Cash flow	**15.0** [(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 principal amount of $118.3 million of 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 earnings coverage ratio for the 12 month period ended June 30, 2001 would be 9.7 and the cash flow coverage ratio for the 12 month period ended June 30, 2001 would be 14.1.

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Daylight Time, 11:00 a.m. Eastern Daylight Time, Wednesday, August 8, 2001. The North America conference call number is 1-888-294-1704 and the outside North America conference call number is 1-416-620-2402. 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 1-800-473-0602 and for those outside North America call 1-905-502-3723.

Media are invited to participate in listen only mode.

Replay: A taped rebroadcast will be available until August 15, 2001 (inclusive). To access postview in North America dial 1-800-558-5253 and enter the passcode 19373881. Those outside of North America dial 1-416-626-4100 and enter the reservation number 19373844.

THIRD QUARTER 2001 RESULTS

Third quarter 2001 results are scheduled for release Wednesday, November 7, 2001. A conference call will be held on this date at 9:00 a.m. Mountain Standard Time, 11:00 a.m. Eastern Standard Time.

For more information, please contact:

ALLAN P. MARKIN
Chairman

JOHN G. LANGILLE
President

STEVE W. LAUT
Senior Vice-President, Operations

CANADIAN NATURAL RESOURCES LIMITED
2500, 855 – 2nd Street S.W., Calgary, Alberta, T2P 4J8
Telephone: (403) 517-6700 **Facsimile:** (403) 517-7350
Email: investor.relations@cnrl.com **Website:** www.cnrl.com

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