CANADIAN NATURAL RESOURCES LIMITED

Press Release

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2001 FOURTH QUARTER RESULTS

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In commenting on fourth quarter and 2001 year end results, Chairman Allan Markin stated "2001 has been a year of strengthening our position as a product-diversified exploration and development company. Our assets in all areas have never looked better with defined growth strategies in place for natural gas, oil (light, medium and heavy) and synthetic light oil. We grew our year-over-year natural gas exit volumes by close to 30%, we continued to develop our international portfolio of light oil assets and we made significant strides in making our Horizon oil sands project a reality."

"As we look into 2002 we see further growth. Already this year we have achieved first oil at our international development in Côte d'Ivoire. The Espoir project was on time and on budget, and has initial production levels in excess of our original expectations. We hope to add to this international success with additional drilling in Côte d'Ivoire, where the Baobab exploration well was followed by the drilling of a second successful well and where a new nearby prospect called Kossipo will be drilled."

"In Canada, our natural gas success continues with new pipeline capacity to the Ladyfern field scheduled to commence in March and five new Ladyfern "lookalike" structures being drilled this winter. At Pelican Lake, we will commence testing of our new emulsion flood that could add significantly to the total oil reserves recovered from the pool. On our world class oil sands project, Horizon, we initiate formal regulatory processes in June with anticipated construction commencing in 2004."

"Finally, our proactive curtailment of heavy oil production, including a reduction in the number of heavy oil wells drilled and a change in the steaming pattern at Primrose, has helped to narrow the heavy oil differential back to historical levels. We continue to monitor this market and continue to work on strategies to eliminate some of the uncertainty surrounding this commodity pricing."

"The entire management team is very excited about our prospects, and we look forward to continuing to deliver top tier results to our shareholders."

HIGHLIGHTS

- Cash flow reached $1.9 billion ($15.83 per common share) consistent with the $1.9 billion ($16.14 per common share) realized in 2000. Fourth quarter cash flow was $326 million ($2.69 per common share).

- Earnings amounted to $698 million ($5.76 per common share) compared with $782 million ($6.70 per common share) earned in 2000. Fourth quarter earnings, after reflecting an after tax loss of $19 million on sale of assets in the United States, amounted to $52 million ($0.43 per common share).

- Total average production of 359,347 barrels of oil equivalent per day in 2001, increased 17% over the 305,987 barrels of oil equivalent per day produced in 2000.

- Fourth quarter average natural gas sales were over one billion cubic feet per day, an increase of 88 million cubic feet per day over third quarter production levels and 180 million cubic feet per day over prior year amounts.

- Fourth quarter oil and liquids sales were 198,000 barrels per day after curtailment of heavy oil development and production.

- Netback per barrel of oil equivalent in the fourth quarter averaged a healthy $11.68 despite weakening North American commodity pricing.

- Trailing 12-month after tax return on average common shareholders' equity amounted to 20% and our after tax return on capital employed was 13%.

- Completed testing and tie-in of Slave Point wells at Ladyfern, British Columbia with production currently at a facility restricted rate of 170 to 180 million cubic feet per day.

- Further consolidation of the Company's holdings in northeastern British Columbia with the fourth quarter acquisition of our partner's interest in the Helmet area.

- Extension of the 100% owned ECHO Pipeline System to connect with other Canadian Natural heavy oil producing properties.

- Proven and probable reserve additions equalled 1.6 times 2001 production (1.3 times using only proven reserves), at a finding, development and on stream cost of $8.47 per barrel of oil equivalent ($9.97 using only proven reserves).

- Total proven gross reserves at the end of 2001 amounted to 790 million barrels of oil and liquids and 2.7 trillion cubic feet of natural gas (1.2 billion barrels of oil equivalent) with additional probable reserves of 169 million barrels of oil and liquids and 0.4 trillion cubic feet of natural gas.

- Commenced role as operator of the Curlew Floating Production Storage and Offtake ("FPSO") vessel in the central North Sea. This vessel processes the volumes produced from the Kyle field and has the potential to handle additional volumes.

- Continued development of the Canadian Natural operated Espoir field in Côte d'Ivoire with the arrival of the FPSO on time and on budget. First oil from this development commenced in February 2002.

- In January 2002, completed a United States debt offering for US $400 million of 30 year notes at an interest rate of 7.20%.

- In January 2002, extended for an additional 12-month period its Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange and the New York Stock Exchange for the purchase of up to 5% of our outstanding common shares or 6 million shares at the market price if and when acquired.

- In February 2002, the Board of Directors increased the Company's quarterly dividend by 25% to $0.125 per share commencing with the April 1, 2002 payment.

OPERATIONS REVIEW

Production

The 2001 annual results show the strength of the Company's business approach to diversification among commodities produced, namely natural gas, light and medium oil and heavy oil. Canadian Natural believes this diversification reduces price risk when compared with over leverage to one commodity.

Natural gas continues to be Canadian Natural's largest product offering with fourth quarter 2001 natural gas production averaging over one billion cubic feet per day, an increase of 88 million cubic feet per day from the third quarter of 2001 and 180 million cubic feet per day from the fourth quarter of 2000. During the fourth quarter, production from the Ladyfern pool in northeast British Columbia averaged a pipeline constrained 104 million cubic feet per day.

Oil and liquids production in the fourth quarter of 2001 decreased 4% from the third quarter of this year, reflecting the reduced heavy oil drilling program and the proactive decision to defer 15,000 barrels of oil per day of production until heavy oil differentials narrow to more historical levels.

The Company's production composition was as follows:

	Q4 2001		Q3 2001		Q4 2000	
	mboe/d	%	mboe/d	%	mboe/d	%
Natural gas	**168.6**	**46**	154.0	43	138.6	41
Light and medium oil	**105.3**	**29**	112.1	31	106.8	31
Heavy oil	**92.7**	**25**	94.9	26	96.0	28
	366.6		361.0		341.4	

Canadian Natural drilled an additional three net oil wells and 16 net natural gas wells during the fourth quarter. These wells were located in the Company's oil area of Pelican Lake, Alberta and its natural gas core areas in northeast British Columbia and south central Alberta. In addition, 103 stratigraphic tests were drilled on the oil sands leases in Project Horizon and in eastern Alberta. The total success rate for Canadian Natural's drilling program was 100% in the fourth quarter of the year, resulting in a success rate for the entire year of 97%.

Based upon its $1.5 billion dollar budget in 2002, the Company expects to produce an average of 379,000 to 393,000 barrels of oil equivalent per day, a 7% increase over 2001 levels. This increase is comprised of natural gas volumetric increases to between 1,075 and 1,100 million cubic feet per day (versus the average of 918 million cubic feet per day sold in 2001) and average oil and liquids sales to between 200 and 210 thousand barrels of oil per day (versus the average of 206 thousand barrels per day in 2001).

Pricing

Netbacks received for Canadian Natural's oil and liquids production were lower in the fourth quarter of 2001 than both the third quarter of 2001 and the fourth quarter of last year. This was primarily a reflection of lower WTI benchmark pricing. Similarly, natural gas price declines contributed to lower netbacks when compared with the same periods. This decline in natural gas prices is attributable to a reduction in North American demand and high natural gas storage levels in the North American markets.

A comparison of the price received for the Company's natural gas and oil production is as follows:

	Q4 2001	Q3 2001	Q4 2000
WTI benchmark price (US $/bbl)	**$ 20.49**	$ 26.57	$ 31.83
Differential to LLB blend (US $/bbl)	**$ 10.07**	$ 8.10	$ 14.56
Condensate benchmark price (US $/bbl)	**$ 19.64**	$ 26.70	$ 33.91
NYMEX benchmark price (US $/mmbtu)	**$ 2.50**	$ 3.00	$ 5.42
AECO benchmark price (Cdn $/mmbtu)	**$ 3.30**	$ 3.92	$ 7.42
Canadian Natural's Wellhead Price:			
Primary heavy oil ($/bbl)	**$ 15.77**	$ 23.69	$ 16.78
Thermal heavy oil ($/bbl)	**$ 13.59**	$ 22.46	$ 12.42
Pelican Lake oil ($/bbl)	**$ 17.40**	$ 24.99	$ 17.55
Natural gas ($/mcf)	**$ 2.94**	$ 3.12	$ 7.28

North America Conventional

At Ladyfern in northeastern British Columbia, the Company's 2001 drilling program resulted in the drilling, completion and testing of six wells, each capable of production rates in excess of 100 million cubic feet per day. Total production from the Ladyfern area is subject to a production cap agreed to with other producers in the area. This cap will ensure that there is not an over building of facilities 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 is added in the first quarter of 2002, the cap will increase to 785 million cubic feet per day. Canadian Natural's share of this production cap will be established on the basis of productive well capability and it is expected Canadian Natural's share of the production will amount to between 35% and 45%.

The results of wells drilled to date in the Ladyfern area confirm the anomalies identified on Canadian Natural's 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 additional locations with geophysical characteristics similar to the wells drilled to date. Canadian Natural owns a 100% interest in its Ladyfern wells and an additional 30,000 acres of undeveloped land in the area. In 2002, Canadian Natural will drill a further 10 to 12 wells to test the productive capability of Slave Point structures identified in this area. This will include wells on the main Ladyfern structure as well as other structures located on Canadian Natural's land holdings.

At its thermal oil operations at Primrose, Alberta, Canadian Natural converted a further six low pressure cyclic pads to high pressure cyclic pads. This is in addition to the four pads which were previously approved for conversion in 2000. With these conversions, Canadian Natural is better able to control steam injection volumes and timing. As a result, oil production from these high pressure pads will be produced in the second and third quarter of 2002.

In the fourth quarter, Canadian Natural completed the extension to its 100% owned and operated ECHO Pipeline System. This pipeline, together with the Pelican Lake Pipeline (62% owned and operated) and the 15% ownership in the Cold Lake Pipeline, is part of the Company's focus to manage the development, and marketing of its heavy oil production. These midstream assets allow Canadian Natural to transport its own production volumes as well as earn transportation revenues from third parties.

At the time of acquiring Ranger Oil in the summer of 2000, Canadian Natural evaluated the properties owned by Ranger Oil in the United States and determined that those properties would not constitute an ongoing core region for the Company. Accordingly, a large portion of these properties were sold in the fourth quarter for $49 million plus an overriding royalty interest in certain properties. Market prices of oil and natural gas properties had decreased in tandem with commodity prices and, accordingly, an after tax loss on sale of $19 million was realized on the disposition.

North America Project Horizon

Canadian Natural's Horizon oil sands project has completed the first phase of its front-end engineering work. The Company's approach for this project is to extensively evaluate new technology options and predesign the infrastructure prior to construction. In this way, Canadian Natural will ensure cost certainty before significant activity begins. A strong staff of experts with experience in design, construction and operations in each of mining, extraction and upgrading has been assembled to lead this work. With respect to bitumen upgrading, Canadian Natural continues to evaluate various options, including both full and partial upgrading. The applications for project approval with regulatory authorities will be submitted in mid-2002. Canadian Natural continues to schedule the start of construction in 2004 with first synthetic oil production as early as 2007.

Offshore West Africa

During 2001, Canadian Natural continued the development of the Espoir field located offshore Côte d'Ivoire. This development included batch drilling of seven wells to intermediate casing point from one wellhead tower, installation of a natural gas pipeline onshore from the field and in December the arrival in the field of an FPSO vessel, the "Espoir Ivoirien". The FPSO has a processing capacity of 40 thousand barrels of oil per day with a storage capacity of one million barrels. In February 2002, the first producing well completed drilling and was placed on production through the FPSO at an initial rate of 8,500 barrels of oil per day. Canadian Natural is the operator of the Espoir field with a 59% ownership interest.

In deeper water south of Espoir, Canadian Natural drilled an exploration well on the Baobab structure in the first quarter of 2001. This well tested oil at 6,700 barrels per day. A second successful well was drilled and tested at a rate in excess of 10,000 barrels of oil per day, in the first quarter of 2002. A second nearby structure, Kossipo, will also be drilled in 2002. Canadian Natural is operator and holds a 61% working interest in these projects.

The Angolan government has been notified that production from the Kiame field will cease 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.

ACTIVITY BY CORE REGION	Undeveloped Land As at December 31, 2001 (thousands of net acres)	Drilling Activity Year ended December 31, 2001 (net wells)
Northeastern British Columbia/Northwestern Alberta	**1,553**	**92**
North Central Alberta	**2,573**	**185**
Alberta Oil Sands	**236**	**257**
Eastern Alberta/Western Saskatchewan	**1,105**	**222**
South Central Alberta	**654**	**326**
Williston Basin	**151**	**4**
United Kingdom North Sea	**236**	**3**
Offshore West Africa	**1,258**	**2**

	YEAR ENDED DECEMBER 31			
	2001		2000	
DRILLING ACTIVITY	**Gross**	**Net**	**Gross**	**Net**
Oil	**270**	**231**	375	333
Natural gas	**576**	**476**	474	408
Injection/strat tests	**356**	**353**	42	38
Dry	**36**	**32**	46	34
Total	**1,238**	**1,092**	937	813
Success rate		**97%**		96%

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.

In 2001, Canadian Natural realized record cash flow from operations of over $1.9 billion and delivered a capital expenditure program of just under $1.9 billion. The Company also paid out dividends on common shares in the amount of $36 million ($0.40 per share) and initiated a Normal Course Issuer Bid whereby we purchased 2,537,800 common shares for a total cost of $113 million.

Long-term debt at December 31, 2001 amounted to $2.7 billion and reflected a 1.4x debt to cash flow ratio and a debt to book capitalization of 42.5%, both calculated on trailing 12-month activity basis and reflecting our preferred securities as debt equivalents. These ratios are well within the Company's guidelines for balance sheet management.

During 2001, we successfully undertook to diversify our borrowing base through the filing of 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.

In July 2001, the Company issued US $400 million of ten year, 6.70% notes to purchasers in the United States under the above shelf. In January 2002, the Company issued US $400 million of 30 year, 7.20% notes to purchasers in the United States. 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.

During 2001, Canadian Natural cancelled three bank lines of credit aggregating approximately $1 billion. The Company's unutilized bank lines of credit currently exceed $900 million and are in addition to funds that are available through the Company's Canadian and US shelf prospectuses.

In response to the expected demand for oil and natural gas, the related pricing and to protect our capital expenditure programs, we have entered into several financial derivative contracts to manage our exposure to market volatility. The details of our positions are set out in note 6 to the Consolidated Financial Statements and are summarized as follows:

	Q1 2002	Q2 2002	Q3/Q4 2002
Oil Collars (US$ - WTI)			
Volume (bbls/d)	100,500	100,000	50,500
Average floor price (US$/bbl)	$19.61	$19.90	$20.09
Average ceiling price (US$/bbl)	$23.60	$24.05	$24.74
Natural Gas Collars (C$ - AECO)			
Volume (GJ/d)	290,000	230,000	-
Average floor price (Cdn$/GJ)	$3.52	$3.49	-
Average ceiling price (Cdn$/GJ)	$4.38	$4.27	-

Our financial position is strong and we will continue to adhere to our long-term targets ensuring our financial flexibility. In light of this, the Board of Directors announced that the quarterly dividend will increase to $0.125 per common share from $0.10 per common share commencing with the April 1, 2002 payment. The payment will be made to shareholders of record at the close of business on March 15, 2002.

RESERVES

Canadian Natural retains independent petroleum engineering consultants, Sproule Associates Limited ("Sproule"), to evaluate the Company's proven and probable oil and natural gas reserves and prepare Evaluation Reports on the Company's total reserves. For the year ended December 31, 2001, the independent evaluator's reports covered 91% of the Company's reserves with the Company internally evaluating the remaining 9%, which are generally comprised of reserves in properties not currently strategic to the Company's core business areas. The Board of Directors of the Company has a Reserve Committee, which has met with Sproule and carried out independent due diligence procedures with Sproule as to the Company's reserves.

Of interest is the change in proven undeveloped (PUD's) oil reserves year over year. In North America the percentage of PUD's decreased from 41.6% to 40.6% of total proven reserves. Almost all North American PUD's are attributed to heavy oil reserves. This is due to the multi-zone nature of primary heavy oil developments, as not all zones in each wellbore can be brought on stream at the same time when the well is drilled. Thermal heavy oil has a high degree of reservoir delineation (via strat test wells) before development and production is brought on stream. This results in a higher percentage of PUD's compared to conventional oil and natural gas reserve bases.

Natural gas PUD's in North America are low at 10.8% of total proven reserves at the end of 2001, compared to 17.9% at the end of 2000. This reflects the Company's focus on increasing natural gas production in 2001 in a period of high commodity prices.

In offshore West Africa, a significant amount of reserves (51 million barrels) are booked as probable reserves. These are reserves associated with the water flood at Espoir in Côte d'Ivoire. These reserves were not booked as proven reserves at year end 2001 as water injection had not commenced. The Company has been injecting water at Espoir since the middle of February 2002, and on successful implementation of the waterflood these reserves will be moved to proven in the 2002 year end evaluation.

No reserves have been assigned by the Company or Sproule to the Horizon oil sands project. Canadian Natural's internal estimate of recoverable reserves is 5.6 billion barrels of bitumen. Canadian Natural owns 100% of these estimated reserves with production scheduled to commence in 2007.

Canadian Natural's reserves before royalties are summarized in the following tables:

	December 31, 2001				
	Proven Developed	**Proven Undeveloped**	**Proven Total**	**Probable**	**Total**
Crude Oil & Natural Gas Liquids (mmbbls)					
North America	**382**	**262**	**644**	**95**	**739**
North Sea	**54**	**31**	**85**	**23**	**108**
Offshore West Africa	**21**	**40**	**61**	**51**	**112**
	457	**333**	**790**	**169**	**959**
Natural Gas (bcf)					
North America	**2,288**	**278**	**2,566**	**349**	**2,915**
North Sea	**19**	**75**	**94**	**24**	**118**
Offshore West Africa	**17**	**52**	**69**	**27**	**96**
	2,324	**405**	**2,729**	**400**	**3,129**
Total Reserves (mmboe 6:1)	**845**	**400**	**1,245**	**236**	**1,481**
Present value of reserves (millions of dollars)(1)(2)					
10% discount	**$ 7,850**	**$ 1,699**	**$ 9,549**	**$ 847**	**$ 10,396**

	December 31, 2000				
	Proven Developed	**Proven Undeveloped**	**Proven Total**	**Probable**	**Total**
Crude Oil & Natural Gas Liquids (mmbbls)					
North America	375	267	642	88	730
North Sea	72	30	102	33	135
Offshore West Africa	3	34	37	9	46
	450	331	781	130	911
Natural Gas (bcf)					
North America	1,937	423	2,360	402	2,762
North Sea	31	60	91	23	114
Offshore West Africa	-	66	66	19	85
	1,968	549	2,517	444	2,961
Total Reserves (mmboe 6:1)	778	423	1,201	204	1,405
Present value of reserves (millions of dollars) (1)(2)					
10% discount	$ 9,257	$ 2,295	$ 11,552	$ 868	$ 12,420

(1) Excludes provisions for abandonment costs and income taxes
(2) Value of the probable reserves are reduced by 50% to account for risk

Reserves Reconciliation

	Crude oil and liquids (mmbbls)				Natural gas (bcf)			
Proven Reserves	North America	North Sea	Offshore West Africa	Total	North America	North Sea	Offshore West Africa	Total
Reserves, December 31, 1999	554	-	-	554	2,183	-	-	2,183
Discoveries and purchases	144	105	36	285	517	89	64	670
Property disposals	(15)	-	-	(15)	(41)	-	-	(41)
Production	(57)	(6)	(1)	(64)	(290)	(1)	-	(291)
Revisions of prior estimates	16	3	2	21	(9)	3	2	(4)
Reserves, December 31, 2000	642	102	37	781	2,360	91	66	2,517
Discoveries and purchases	30	-	46	76	637	1	24	662
Property disposals	(1)	-	-	(1)	(25)	-	-	(25)
Production	(61)	(13)	(1)	(75)	(331)	(4)	-	(335)
Revisions of prior estimates	34	(4)	(21)	9	(75)	6	(21)	(90)
Proven Reserves, December 31, 2001	644	85	61	790	2,566	94	69	2,729
Probable Reserves (Unrisked)								
Reserves, December 31, 1999	86	-	-	86	364	-	-	364
Discoveries and purchases	22	35	9	66	63	21	4	88
Property disposals	(10)	-	-	(10)	(4)	-	-	(4)
Revisions of prior estimates	(10)	(2)	-	(12)	(21)	2	15	(4)
Reserves, December 31, 2000	88	33	9	130	402	23	19	444
Discoveries and purchases	-	(1)	19	18	32	(1)	11	42
Property disposals	-	-	-	-	(6)	-	-	(6)
Revisions of prior estimates	7	(9)	23	21	(79)	2	(3)	(80)
Probable Reserves, December 31, 2001	95	23	51	169	349	24	27	400
Proven & Probable Reserves, December 31, 2001	739	108	112	959	2,915	118	96	3,129

Future oil and natural gas price forecasts used in the Evaluation Reports were based on Sproule's January 1, 2002 pricing model and adjusted for quality of reserves and transportation. The prices used for the subsequent five years in the Evaluation Reports are as follows:

	Oil				Natural Gas			
YEAR	Company Average Price $CDN/BBL	WTI At Cushing Oklahoma $US/BBL	Hardisty Heavy 12 API $CDN/BBL	Brent UK $US/BBL	Company Average Price $CDN/MCF	Henry Hub Louisiana $US/MMBTU	Alberta Plantgate $CDN/MMBTU	British Columbia Plantgate $CDN/MMBTU
As at December 31, 2001								
2002	18.36	19.90	14.41	18.40	3.80	2.89	3.80	3.75
2003	20.85	20.64	18.44	19.11	4.33	3.24	4.35	4.30
2004	23.44	21.12	21.58	19.29	4.32	3.25	4.36	4.26
2005	23.75	21.44	22.13	19.58	4.33	3.25	4.36	4.26
2006	24.01	21.76	22.62	19.87	4.42	3.29	4.44	4.34
As at December 31, 2000								
2001	28.52	28.20	21.87	26.60	8.78	6.34	8.40	9.02
2002	26.41	24.41	21.84	22.78	6.00	4.56	5.87	6.09
2003	23.64	21.12	20.54	19.47	4.99	3.88	4.91	4.98
2004	23.64	21.44	21.01	19.76	4.78	3.73	4.76	4.59
2005	23.59	21.76	20.98	20.06	4.69	3.63	4.75	4.34

Finding and Development Costs

	2001	3 Year
Net reserve replacement expenditures ($ millions)	$1,754	$6,476
Reserve additions (mmboe 6:1)		
Proven reserves	176	959
Proven plus probable reserves	207	1,046
On stream cost ($/boe)		
Proven reserves	$9.97	$6.75
Proven plus probable reserves	$8.47	$6.19

Reserve Life Index

	Crude Oil & NGLs (mmbbls)	Natural Gas (bcf)	BOE (mmboe 6:1)
2001 Year end reserves			
Proven reserves	790	2,729	1,245
Proven plus probable reserves	959	3,129	1,481
2001 Fourth quarter production, annualized	72	369	134
Reserve Life Index (years)			
Proven reserves	11.0	7.4	9.3
Proven plus probable reserves	13.3	8.5	11.1

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 consolidated financial statements for the periods ended December 31, 2001 and the MD&A and the 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			YEAR ENDED	
	DEC 31 2001	SEPT 30 2001	DEC 31 2000	DEC 31 2001	DEC 31 2000
FINANCIAL HIGHLIGHTS ($ millions, except per share amounts)					
Gross revenue	**$ 661**	$ 806	$ 1,031	**$ 3,561**	$ 3,223
Cash flow attributable to common shareholders [1]	**$ 326**	$ 437	$ 553	**$ 1,920**	$ 1,884
Per share – basic	**$ 2.69**	$ 3.63	$ 4.56	**$ 15.83**	$ 16.14
– diluted	**$ 2.63**	$ 3.50	$ 4.39	**$ 15.25**	$ 15.64
Net earnings attributable to common shareholders [1]	**$ 52**	$ 132	$ 223	**$ 698**	$ 782
Per share – basic	**$ 0.43**	$ 1.10	$ 1.84	**$ 5.76**	$ 6.70
– diluted	**$ 0.43**	$ 1.08	$ 1.77	**$ 5.56**	$ 6.50
Capital expenditures, net of dispositions	**$ 530**	$ 352	$ 195	**$ 1,885**	$ 1,136
Acquisition of Ranger Oil Limited	**$ -**	$ -	$ -	**$ -**	$ 1,687

[1] After dividend on preferred securities

	DEC 31 2001	SEPT 30 2001	DEC 31 2000	DEC 31 2001	DEC 31 2000
OPERATING HIGHLIGHTS					
Oil and liquids					
Daily production (bbls)	**198,000**	207,065	202,732	**206,323**	173,591
Sales price	**$ 21.28**	$ 28.37	$ 25.37	**$ 24.31**	$ 29.99
Royalties	**1.41**	2.47	2.83	**2.17**	3.05
Operating costs	**7.41**	7.10	7.60	**7.42**	6.38
Netback ($/bbl)	**$ 12.46**	$ 18.80	$ 14.94	**$ 14.72**	$ 20.56
Natural gas					
Daily production (mmcf)	**1,012**	924	832	**918**	794
Sales price	**$ 2.94**	$ 3.12	$ 7.28	**$ 5.16**	$ 4.53
Royalties	**0.62**	0.67	1.83	**1.25**	1.08
Operating costs	**0.53**	0.50	0.47	**0.51**	0.44
Netback ($/mcf)	**$ 1.79**	$ 1.95	$ 4.98	**$ 3.40**	$ 3.01
Barrel of oil equivalent (6:1)					
Daily production (boe)	**366,594**	361,029	341,369	**359,347**	305,987
Sales price	**$ 19.62**	$ 24.25	$ 32.82	**$ 27.15**	$ 28.77
Royalties	**2.47**	3.14	6.13	**4.42**	4.51
Operating costs	**5.47**	5.36	5.66	**5.57**	4.76
Netback ($/boe)	**$ 11.68**	$ 15.75	$ 21.03	**$ 17.16**	$ 19.50

Cash flow for the year ended December 31, 2001, increased over the prior year due to higher natural gas prices and increased production volumes. Fourth quarter cash flow decreased from third quarter 2001 due mainly to the continuing effects of weaker market prices for both oil and natural gas and lower oil and liquids production during the quarter. Net earnings for the year and quarter ended December 31, 2001 decreased as a result of higher depletion costs and the recognition of a loss on sale of United States assets acquired through the Ranger Oil Limited ("Ranger") acquisition.

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2001	SEPT 30 2001	DEC 31 2000	DEC 31 2001	DEC 31 2000
DAILY PRODUCTION					
Oil and liquids (bbls/day)					
North America	**159,000**	162,890	167,464	**166,675**	154,331
North Sea	**35,749**	40,356	30,721	**36,252**	17,195
Offshore West Africa	**3,251**	3,819	4,547	**3,396**	2,065
Total	**198,000**	207,065	202,732	**206,323**	173,591
Natural gas (mmcf/day)					
North America	**993**	906	832	**906**	793
North Sea	**19**	18	-	**12**	1
Total	**1,012**	924	832	**918**	794

Production increased over the prior year due to the inclusion of a full year of results from the Ranger acquisition, which was completed in the third quarter of 2000, and the Company's focus on natural gas drilling. North America fourth quarter 2001 oil and liquids production decreased from third quarter 2001 due to the focus on natural gas drilling and reduced oil recovery from the deferral of steam stimulation of thermal heavy oil production initiated in the first half of the year. Fourth quarter oil and liquids production was also affected by the Company's decision in mid-December 2001 to cap heavy oil production, resulting in production being reduced by 15,000 bbls per day. This decision was in response to recent declines in world oil prices and unusually high heavy oil differentials. Natural gas production in the fourth quarter of 2001 averaged over one bcf per day due to the acquisition of additional Canadian natural gas assets in the Helmet area in northeastern British Columbia and the successful discovery at Ladyfern, where seven wells were drilled and completed in 2001 and production ended the year at 150 mmcf per day.

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2001	SEPT 30 2001	DEC 31 2000	DEC 31 2001	DEC 31 2000
PRODUCT PRICES					
Oil and liquids ($/bbl)					
North America	**$ 18.59**	$ 26.02	$ 21.61	**$ 21.00**	$ 28.15
North Sea	**$ 33.39**	$ 37.28	$ 43.86	**$ 38.66**	$ 44.61
Offshore West Africa	**$ 19.56**	$ 34.66	$ 39.10	**$ 33.57**	$ 45.77
Company average	**$ 21.28**	$ 28.37	$ 25.37	**$ 24.31**	$ 29.99
Natural gas ($/mcf)					
North America	**$ 2.94**	$ 3.13	$ 7.28	**$ 5.19**	$ 4.53
North Sea	**$ 3.00**	$ 2.51	$ 3.78	**$ 2.51**	$ 3.66
Company average	**$ 2.94**	$ 3.12	$ 7.28	**$ 5.16**	$ 4.53

The realized oil price for the year ended December 31, 2001 decreased from the comparable period in 2000 primarily due to lower world oil prices, which averaged US $25.91 per bbl in 2001 compared to US $30.20 per bbl in 2000. In the fourth quarter, world oil market prices continued to decline, averaging US $20.49 per bbl compared to US $26.57 per bbl in the third quarter 2001; while the heavy oil differential increased to US $10.07 per bbl from US $8.10 per bbl in the third quarter. The Company was able to mitigate some of the effects of lower WTI prices and the higher heavy oil differential through the use of costless oil collars. The costless collars and other arrangements entered into by the Company to fix a portion of the price realized from the sale of oil increased the price by $4.79 per bbl in the quarter ended December 31, 2001 ($0.22 and $2.13 reductions per bbl, respectively, in the quarters ended September 30, 2001 and December 31, 2000).

North American realized natural gas prices increased in the year 2001 over the prior year due to a tighter supply environment in the first half of the year. Realized natural gas prices continued to decrease in the fourth quarter 2001 due to lower demand and high natural gas storage levels in the North American market. The price realized from the sale of natural gas was reduced by $0.03 per mcf in the fourth quarter 2001 ($0.10 and $0.63 reductions per mcf, respectively, in the quarters ended September 30, 2001 and December 31, 2000) due to price arrangements entered into by the Company.

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2001	SEPT 30 2001	DEC 31 2000	DEC 31 2001	DEC 31 2000
ROYALTIES					
Oil and liquids ($/bbl)					
North America	**$ 1.40**	$ 2.61	$ 2.90	**$ 2.22**	$ 3.17
North Sea	**$ 1.52**	$ 1.97	$ 2.89	**$ 2.10**	$ 2.40
Offshore West Africa	**$ 0.64**	$ 2.03	$ -	**$ 0.93**	$ -
Natural gas ($/mcf)					
North America	**$ 0.63**	$ 0.68	$ 1.83	**$ 1.26**	$ 1.08
Company average ($/boe)	**$ 2.47**	$ 3.14	$ 6.13	**$ 4.42**	$ 4.51

Oil and liquids royalties declined in North America in the year 2001 from the prior year due to lower world oil prices and the continuing benefit of a lower royalty structure on the Company's production of primary and thermal heavy oil. In the fourth quarter of 2001, North America oil and liquids royalties decreased from the third quarter 2001 due to lower realized prices as a result of the higher heavy oil differentials and lower world oil prices. North Sea oil and liquids royalties per bbl decreased in the year 2001 as a result of lower oil prices and increased production from the Banff and Kyle fields, which are non-royalty paying fields. In the fourth quarter, North Sea royalties decreased from the third quarter as a result of lower realized prices.

Natural gas royalties increased in the year 2001 compared to the prior year due to the overall increase in natural gas prices.

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2001	SEPT 30 2001	DEC 31 2000	DEC 31 2001	DEC 31 2000
PRODUCTION EXPENSES					
Oil and liquids ($/bbl)					
North America	**$ 6.46**	$ 6.57	$ 7.21	**$ 6.78**	$ 5.93
North Sea	**$ 10.54**	$ 8.09	$ 8.09	**$ 9.00**	$ 8.66
Offshore West Africa	**$ 19.15**	$ 19.05	$ 18.53	**$ 21.77**	$ 20.41
Natural gas ($/mcf)					
North America	**$ 0.52**	$ 0.50	$ 0.47	**$ 0.50**	$ 0.44
North Sea	**$ 1.34**	$ 0.74	$ -	**$ 0.94**	$ 0.79
Company average ($/boe)	**$ 5.47**	$ 5.36	$ 5.66	**$ 5.57**	$ 4.76

The increase in North America oil and natural gas production expenses for the year 2001 from the prior year is attributable to higher associated costs for fuel, power and processing incurred during the first half of the year. The cost of processing thermal heavy oil in Canada has decreased in the last half of the year as a result of declining natural gas prices. Natural gas is used to produce the steam injected into the oil formation for the production of thermal heavy oil. North Sea production expenses for both oil and natural gas increased from the third quarter and prior year primarily due to costs associated with higher tariff rates on the Columba B and D fields and decreased production over which fixed costs are allocated. Offshore West Africa operating costs are mainly fixed in nature and therefore increased on a per bbl basis due to decreased oil production volumes from the Kiame field in Angola.

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2001	**SEPT 30 2001**	**DEC 31 2000**	**DEC 31 2001**	**DEC 31 2000**
DEPLETION, DEPRECIATION AND AMORTIZATION					
Expense ($ millions)	**$ 242.4**	$ 236.2	$ 202.2	**$ 903.8**	$ 644.6
$/boe	**$ 7.19**	$ 7.11	$ 6.43	**$ 6.89**	$ 5.75

Depletion costs increased in the year 2001 over the prior year due to higher costs associated with the Company's increased emphasis on natural gas drilling and completion in North America as well as higher depletion costs in the North Sea and offshore West Africa segments acquired with Ranger.

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2001	**SEPT 30 2001**	**DEC 31 2000**	**DEC 31 2001**	**DEC 31 2000**
ADMINISTRATION EXPENSE					
Net expense ($ millions)	**$ 12.0**	$ 9.4	$ 10.3	**$ 37.6**	$ 27.2
$/boe	**$ 0.36**	$ 0.28	$ 0.33	**$ 0.29**	$ 0.25

Administration costs in 2001 have increased from the prior year mainly due to increased staffing levels. Costs increased in the fourth quarter of 2001 reflecting lower recoveries related to the capital program.

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2001	**SEPT 30 2001**	**DEC 31 2000**	**DEC 31 2001**	**DEC 31 2000**
INTEREST EXPENSE					
Interest expense ($ millions)	**$ 31.4**	$ 32.2	$ 45.8	**$ 137.8**	$ 162.3
$/boe	**$ 0.93**	$ 0.97	$ 1.45	**$ 1.05**	$ 1.45
Average effective interest rate	**4.23%**	5.35%	6.61%	**5.37%**	6.38%

Interest expense decreased in 2001 from the prior year due to lower debt levels in the first three quarters of the year and declining interest rates. Interest expense decreased in the fourth quarter due to the decline in interest rates.

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2001	SEPT 30 2001	DEC 31 2000	DEC 31 2001	DEC 31 2000
TAXES ($ millions)					
Taxes other than income tax					
Current	**$ 10.1**	$ 21.1	$ 29.9	**$ 69.3**	$ 57.1
Deferred	**$ 1.0**	$ (1.3)	$ (3.6)	**$ (0.2)**	$ (7.6)
Current income tax					
North Sea	**$ 10.3**	$ 16.5	$ 14.4	**$ 61.8**	$ 33.7
Large corporation tax	**$ 4.7**	$ 3.2	$ 4.4	**$ 15.1**	$ 14.7
Future income tax	**$ 1.8**	$ 61.0	$ 130.1	**$ 282.5**	$ 464.0
Effective tax rate	**23.9%**	37.6%	39.9%	**33.8%**	39.5%

North Sea current income tax increased for the year 2001 as a result of a full year of production from these properties acquired through the acquisition of Ranger. Current income tax decreased for this segment in the fourth quarter of 2001 due to decreased earnings before taxes.

The future income tax expense in the fourth quarter of 2001 decreased from the third quarter of 2001 and fourth quarter 2000 as a result of lower earnings before tax and a decrease in a Province of Canada's corporate income tax rate, resulting in a one-time $17 million reduction in the future income tax liability. Future income tax expense in 2001 decreased from 2000 due to reductions in certain Canadian provinces' corporate income tax rates during 2001, resulting in a one-time reduction in the future income tax liability in the aggregate amount of $63 million.

	DEC 31 2001	SEPT 30 2001	DEC 31 2000
LIQUIDITY AND CAPITAL RESOURCES			
Working capital deficit	**$ 5.6**	$ 154.1	$ 77.3
Long-term debt	**$ 2,669.2**	$ 2,311.8	$ 2,454.5
Shareholders' equity			
Preferred securities	**$ 118.3**	$ 118.3	$ 118.3
Share capital and contributed surplus	**1,698.3**	1,693.9	1,692.6
Retained earnings	**1,979.5**	1,939.5	1,406.0
Foreign currency translation adjustment	**72.8**	-	-
Total shareholders' equity	**$ 3,868.9**	$ 3,751.7	$ 3,216.9
Debt to cash flow [1] [2]	**1.4x**	1.1x	1.3x
Debt to book capitalization [1]	**42.5%**	40.1%	45.4%
Debt to market capitalization [1]	**36.5%**	33.0%	32.6%
After tax return on average common shareholders' equity [2]	**20.1%**	26.4%	32.4%
After tax return on average capital employed [2]	**13.0%**	16.4%	18.1%

[1] Includes preferred securities as debt equivalents
[2] Based on trailing 12-month activity

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2001	SEPT 30 2001	DEC 31 2000	DEC 31 2001	DEC 31 2000
CAPITAL EXPENDITURES ($ millions)					
Acquisition of Ranger Oil Limited	**$ -**	$ -	$ -	**$ -**	$ 1,687.3
Expenditures on property, plant and equipment					
Net property acquisitions (dispositions)	**$ 248.4**	$ 24.6	$ (92.7)	**$ 519.2**	$ 150.2
Land acquisition and retention	**15.5**	35.8	45.7	**100.5**	79.7
Seismic evaluations	**28.8**	8.6	18.1	**94.6**	40.5
Well drilling, completion and equipping	**109.9**	153.6	125.8	**644.7**	524.0
Pipeline and production facilities	**68.9**	109.7	98.2	**395.0**	335.7
Total net reserve replacement expenditures	**$ 471.5**	$ 332.3	$ 195.1	**$ 1,754.0**	$ 1,130.1
Midstream operations	**45.5**	16.1	-	**97.3**	-
Oil sands	**11.0**	1.9	-	**26.8**	-
Head office	**1.7**	1.8	0.3	**6.4**	5.9
Total net capital expenditures	**$ 529.7**	$ 352.1	$ 195.4	**$ 1,884.5**	$ 1,136.0
By Segment					
North America	**$ 452.3**	$ 297.0	$ 144.6	**$ 1,582.8**	$ 1,041.8
North Sea	**34.3**	32.2	29.6	**97.8**	54.9
Offshore West Africa	**43.1**	22.9	21.2	**203.9**	39.3
	$ 529.7	$ 352.1	$ 195.4	**$ 1,884.5**	$ 1,136.0

North America capital expenditures include the continuing development of the Ladyfern field where a total of seven wells were drilled and completed in 2001. North America fourth quarter capital expenditures include the acquisition of producing natural gas assets and undeveloped land in the Helmet area, the completion of phase one of the front-end engineering work for development of oil sands leases in the Horizon project, the disposal of substantially all of the US assets acquired in the Ranger acquisition, and the completion of the extension to our 100% owned ECHO Pipeline System. The expansion of the midstream assets, including Pelican Lake Pipeline (62% owned and operated) and the 15% ownership in the Cold Lake Pipeline, is part of the Company's ongoing focus to manage the development, production and marketing of its heavy oil. The midstream assets will allow the Company to transport its own production volumes at reduced operating costs as compared to other transportation alternatives as well as earn third party transportation revenue.

Internationally, fourth quarter capital expenditures include exploration in the Acorn/Beechnut field in the North Sea, and the continuing development of the Espoir field located offshore West Africa.

SENSITIVITY ANALYSIS[1]

Annualized sensitivities to certain factors, which would influence the Company's financial results, are 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	$98	$0.80	$69	$0.57
Including financial derivatives	$74 – $98	$0.61 – $0.80	$52 – $69	$0.43 – $0.57
Natural gas – Cdn $1.00/mcf [3]				
Excluding financial derivatives	$285	$2.35	$174	$1.43
Including financial derivatives	$231 – $267	$1.90 – $2.20	$141 – $163	$1.16 – $1.34
Volume changes				
Oil – 10,000 bbls/day	$36	$0.30	$6	$0.05
Natural gas – 10 mmcf/day	$7	$0.05	$1	$0.01
Foreign currency rate change [3]				
$0.01 increase in Cdn $ in relation to US $				
Excluding financial derivatives	$30	$0.25	$18	$0.15
Including financial derivatives	$24 – $28	$0.20 – $0.23	$15 – $17	$0.12 – $0.14
Interest rate change 1%	$20	$0.16	$12	$0.10

[1] The sensitivities are calculated based on 2001 fourth quarter results.
[2] Attributable to common shareholders
[3] For details of financial derivatives in place, see financial statement note 6.

OTHER OPERATING HIGHLIGHTS

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2001	SEPT 30 2001	DEC 31 2000	DEC 31 2001	DEC 31 2000
NETBACK ANALYSIS					
Barrel of oil equivalent (6:1)					
Daily production (boe)	**366,594**	361,029	341,369	**359,347**	305,987
Sales price	**$ 19.62**	$ 24.25	$ 32.82	**$ 27.15**	$ 28.77
Royalties	**2.47**	3.14	6.13	**4.42**	4.51
Operating costs	**5.47**	5.36	5.66	**5.57**	4.76
Netback per boe	**11.68**	15.75	21.03	**17.16**	19.50
Administration	**0.36**	0.28	0.33	**0.29**	0.25
Interest	**0.93**	0.97	1.45	**1.05**	1.45
Foreign exchange (gain) loss	**(0.09)**	0.02	0.02	**(0.01)**	-
Taxes other than income tax	**0.30**	0.64	0.95	**0.53**	0.51
Current income tax (North Sea)	**0.31**	0.49	0.46	**0.47**	0.30
Current income tax (Large Corporation Tax)	**0.14**	0.10	0.14	**0.11**	0.13
Cash flow per boe	**$ 9.73**	$ 13.25	$ 17.68	**$ 14.72**	$ 16.86

	YEAR ENDED DECEMBER 31, 2001			
	North America	North Sea	Offshore West Africa	Total
Oil and liquids				
Daily production (bbls)	**166,675**	**36,252**	**3,396**	**206,323**
Sales price	**$ 21.00**	**$ 38.66**	**$ 33.57**	**$ 24.31**
Royalties	**2.22**	**2.10**	**0.93**	**2.17**
Operating costs	**6.78**	**9.00**	**21.77**	**7.42**
Netback ($/bbl)	**$ 12.00**	**$ 27.56**	**$ 10.87**	**$ 14.72**
Natural gas				
Daily production (mmcf)	**906**	**12**	**-**	**918**
Sales price	**$ 5.19**	**$ 2.51**	**$ -**	**$ 5.16**
Royalties	**1.26**	**-**	**-**	**1.25**
Operating costs	**0.50**	**0.94**	**-**	**0.51**
Netback ($/mcf)	**$ 3.43**	**$ 1.57**	**$ -**	**$ 3.40**
Barrel of oil equivalent (6:1)				
Daily production (boe)	**317,658**	**38,293**	**3,396**	**359,347**
Sales price	**$ 25.85**	**$ 37.42**	**$ 33.57**	**$ 27.15**
Royalties	**4.76**	**1.99**	**0.93**	**4.42**
Operating costs	**5.00**	**8.82**	**21.77**	**5.57**
Netback ($/boe)	**$ 16.09**	**$ 26.61**	**$ 10.87**	**$ 17.16**

CONSOLIDATED BALANCE SHEET (millions of Canadian dollars) (unaudited)

	DECEMBER 31 2001	DECEMBER 31 2000
Assets		
Current assets		
Cash	**$ 15.0**	$ 28.0
Accounts receivable and other	**509.0**	584.0
	524.0	612.0
Property, plant and equipment, net	**8,442.9**	7,141.5
Deferred charges	**73.8**	22.1
	$ 9,040.7	$ 7,775.6
Liabilities		
Current liabilities		
Accounts payable	**$ 249.5**	$ 301.1
Accrued liabilities	**264.2**	371.7
Current portion of long-term debt (note 3)	**15.9**	16.5
	529.6	689.3
Long-term debt (note 3)	**2,669.2**	2,454.5
Future site restoration	**193.8**	170.5
Future income tax (note 4)	**1,779.2**	1,244.4
	5,171.8	4,558.7
Shareholders' Equity		
Preferred securities	**118.3**	118.3
Share capital and contributed surplus (note 5)	**1,698.3**	1,692.6
Retained earnings	**1,979.5**	1,406.0
Foreign currency translation adjustment (note 1)	**72.8**	-
	3,868.9	3,216.9
	$ 9,040.7	$ 7,775.6

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

	THREE MONTHS ENDED DEC 31		YEAR ENDED DEC 31	
	2001	**2000**	**2001**	**2000**
Revenue				
Oil and natural gas	**$ 661.5**	$ 1,030.9	**$ 3,561.4**	$ 3,222.5
Less: royalties	**83.2**	192.6	**580.3**	506.2
	578.3	838.3	**2,981.1**	2,716.3
Expenses				
Production	**184.5**	177.8	**730.5**	532.9
Depletion, depreciation and amortization	**242.4**	202.2	**903.8**	644.6
Administration	**12.0**	10.3	**37.6**	27.2
Interest	**31.4**	45.8	**137.8**	162.3
Foreign exchange loss	**2.4**	2.4	**14.7**	2.4
Loss on sale of United States assets	**24.1**	-	**24.1**	-
	496.8	438.5	**1,848.5**	1,369.4
Earnings Before Taxes	**81.5**	399.8	**1,132.6**	1,346.9
Taxes other than income tax	**11.1**	26.3	**69.1**	49.5
Current income tax	**15.0**	18.8	**76.9**	48.4
Future income tax (note 4)	**1.8**	130.1	**282.5**	464.0
Net Earnings	**53.6**	224.6	**704.1**	785.0
Dividend on preferred securities, Net of tax	**(1.6)**	(1.4)	**(5.9)**	(2.8)
Net Earnings Attributable to Common Shareholders	**$ 52.0**	$ 223.2	**$ 698.2**	$ 782.2
Net earnings per common share attributable to common shareholders (note 2)				
Basic	**$ 0.43**	$ 1.84	**$ 5.76**	$ 6.70
Diluted	**$ 0.43**	$ 1.77	**$ 5.56**	$ 6.50
Weighted average common shares outstanding (thousands)(note 2)				
Basic			**121,300**	116,701
Diluted			**126,572**	120,732

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

	YEAR ENDED DEC 31	
	2001	**2000**
Balance – Beginning of Period	**$ 1,406.0**	$ 623.8
Net earnings	**704.1**	785.0
Repurchase of common shares (note 5)	**(76.2)**	-
Dividend on common shares (note 5)	**(48.5)**	-
Dividend on preferred securities, net of tax	**(5.9)**	(2.8)
Balance – End of Period	**$ 1,979.5**	$ 1,406.0

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

	THREE MONTHS ENDED DEC 31		YEAR ENDED DEC 31	
	2001	**2000**	**2001**	**2000**
Operating Activities				
Net earnings	**$ 53.6**	$ 224.6	**$ 704.1**	$ 785.0
Non-cash items				
Depletion, depreciation and amortization	**242.4**	202.2	**903.8**	644.6
Loss on sale of United States assets	**24.1**	-	**24.1**	-
Deferred petroleum revenue tax (recovery)	**1.0**	(3.6)	**(0.2)**	(7.6)
Future income tax	**1.8**	130.1	**282.5**	464.0
Unrealized foreign exchange loss	**5.4**	1.9	**16.0**	2.6
Cash flow provided from operations	**328.3**	555.2	**1,930.3**	1,888.6
Net change in non-cash working capital	**(32.6)**	11.0	**(42.2)**	(55.4)
	295.7	566.2	**1,888.1**	1,833.2
Financing Activities				
Increase (repayment) of bank credit facilities	**350.6**	(436.4)	**(442.3)**	(187.7)
Repayment of limited recourse loan	**-**	(0.7)	**(11.8)**	(0.7)
Repayment of senior unsecured notes	**(15.8)**	(15.1)	**(15.8)**	(15.1)
Issue of US debt securities	**-**	-	**615.2**	-
Issue of medium term notes	**-**	-	**-**	125.0
Issue of capital stock	**4.5**	12.3	**42.8**	66.4
Repurchase of common shares	**-**	-	**(113.3)**	-
Dividend on common shares	**(12.1)**	-	**(36.4)**	-
Dividend on preferred securities	**(2.6)**	(2.5)	**(10.3)**	(5.0)
Net change in non-cash working capital	**(0.1)**	38.1	**7.4**	5.8
	324.5	(404.3)	**35.5**	(11.3)
Investing Activities				
Expenditures on property, plant and equipment	**(578.3)**	(327.7)	**(1,947.5)**	(1,294.6)
Corporate acquisitions	**-**	-	**-**	(722.8)
Net proceeds on sale of property, plant and equipment	**48.6**	134.0	**63.0**	160.3
Net expenditure on property, plant and equipment	**(529.7)**	(193.7)	**(1,884.5)**	(1,857.1)
Net change in non-cash working capital	**(110.5)**	39.3	**(52.1)**	63.1
	(640.2)	(154.4)	**(1,936.6)**	(1,794.0)
(Decrease) Increase in Cash	**(20.0)**	7.5	**(13.0)**	27.9
Cash – Beginning of Period	**35.0**	20.5	**28.0**	0.1
Cash – End of Period	**$ 15.0**	$ 28.0	**$ 15.0**	$ 28.0
Cash flow per share from operations attributable to common shareholders (note 2)				
Basic	**$ 2.69**	$ 4.56	**$ 15.83**	$ 16.14
Diluted	**$ 2.63**	$ 4.39	**$ 15.25**	$ 15.64
Supplemental disclosure of cash flow information				
Interest paid	**$ 28.4**	$ 59.5	**$ 127.4**	$ 169.3
Taxes paid	**$ 42.7**	$ 24.1	**$ 161.2**	$ 62.3

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 consolidated financial statements as at December 31, 2000, except as described below and in note 2. Certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed for this presentation dated February 27, 2002 only.

Foreign Currency Translation

Effective October 1, 2001, the assets and liabilities of foreign operations considered financially and operationally independent are translated into Canadian dollars from their functional currencies using exchange rates at the balance sheet dates. Revenue and expense items are translated using the average rates of exchange throughout the year. Gains and losses resulting from this translation process are included in the foreign currency translation adjustment in shareholders' equity in the Consolidated Balance Sheet.

Transactions and monetary balances denominated in a currency other than a functional currency are translated into the functional currency using month-end exchange rates. Gains and losses arising from this translation process are included in net earnings.

Foreign denominated long-term monetary liabilities of Canadian operations are translated using exchange rates at the balance sheet dates. In 2002, the Company has designated a portion of its United States dollar denominated net debt as a hedge against its net investment in United States dollar based self-sustaining foreign operations and, accordingly, gains and losses resulting from the translation of the net debt will be included in the foreign currency translation adjustment in shareholders' equity in the Consolidated Balance Sheet.

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, 5.3 million common shares were added for the year ended December 31, 2001 (December 31, 2000 – 4.0 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 year ended December 31, 2001, would have been $5.69 and $15.56.

3. LONG-TERM DEBT

	Pro Forma January 1, 2002[1]	December 31 2001	December 31 2000
Bank facilities			
Canadian dollar debt	$ 678.5	**$ 1,003.4**	$ 1,445.7
US dollar debt (2002 – US $100 million, 2001 – US $296 million)	159.3	**471.4**	444.0
Limited recourse loan	-	**-**	11.8
Medium term notes	250.0	**250.0**	250.0
US debt securities (2002 – US $800 million, 2001 – US $400 million)	1,274.0	**637.0**	-
Senior unsecured notes (2001 – US $203 million, 2000 – US $213 million)	323.3	**323.3**	319.5
	2,685.1	**2,685.1**	2,471.0
Current portion of long-term debt	15.9	**15.9**	16.5
	$ 2,669.2	**$ 2,669.2**	$ 2,454.5

[1] On January 23, 2002, the Company issued US $400 million debt securities (note 3(c)). The pro forma calculation gives effect to the proceeds and their initial use.

Credit Facilities

(a) Bank Facilities

At December 31, 2001, 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 totalling $1,500 million and a revolving credit and term loan facility of US $150 million. During the year ended December 31, 2001, the Company repaid and cancelled two credit facilities totalling $975 million as well as the limited recourse loan of $22.1 million.

(b) 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 under this program.

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

(c) 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%. In August 2001, the Company entered into four interest rate swap contracts which convert the fixed rate interest coupon into a floating interest rate (see note 6 – Interest Rate Swaps).

On January 23, 2002, the Company issued US $400 million of US debt securities, maturing January 15, 2032 bearing interest at 7.20%. Subsequently, the Company entered into three interest rate swap contracts which convert a portion of the fixed rate interest coupon into a floating interest rate (see note 6 – Interest Rate Swaps).

4. INCOME TAXES

The Company's future income tax liability has been reduced by $63 million to reflect reductions in certain Canadian provinces' corporate income tax rates during the year.

5. SHARE CAPITAL AND CONTRIBUTED SURPLUS

	December 31 2001	December 31 2000
Common shares	**$ 1,698.3**	$ 1,688.0
Warrants	**-**	2.7
Contributed surplus	**-**	1.9
	$ 1,698.3	$ 1,692.6

Issued

	December 31, 2001	
	Number of shares (000's)	**Amount**
Common shares		
Balance – January 1, 2001	**122,279**	**$ 1,688.0**
Exercise of stock options	**1,005**	**29.2**
Exercise of warrants	**455**	**16.3**
Repurchase of shares under Normal Course Issuer Bid	**(2,538)**	**(35.2)**
Balance – December 31, 2001	**121,201**	**$ 1,698.3**
Warrants		
Balance – January 1, 2001	**465**	**$ 2.7**
Exercised during the period	**(455)**	**(2.7)**
Expired during the period	**(10)**	**(0.0)**
Balance – December 31, 2001	**-**	**$ -**

Stock Options

	December 31, 2001	
	Share options (000's)	**Weighted average exercise price**
Outstanding – January 1, 2001	**10,664**	**$ 32.78**
Granted	**3,500**	**$ 40.85**
Exercised	**(1,005)**	**$ 29.12**
Forfeited	**(1,108)**	**$ 39.89**
Outstanding – December 31, 2001	**12,051**	**$ 34.77**
Exercisable – December 31, 2001	**3,615**	**$ 31.42**

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 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 December 31, 2001, the Company had purchased 2,537,800 common shares for a total cost of $113.3 million.

In January 2002, the Company renewed its Normal Course Issuer Bid, allowing the Company to purchase up to 6,060,180 shares, being 5% of the Company's outstanding common shares on the date of announcement, during the 12-month period beginning January 23, 2002 and ending January 22, 2003.

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 fourth payment made on January 1, 2002 to shareholders of record on December 14, 2001.

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:

	Term	Volume	Average Price	Index
Oil				
Oil price collars	Jan. 2002 – Mar. 2002	65,000 bbls/day	US $19.10 – US $22.28	WTI
	Apr. 2002 – Jun. 2002	31,000 bbls/day	US $19.52 – US $23.37	WTI
	Apr. 2002 – Jun. 2002	18,500 bbls/day	US $20.00 – US $23.33	WTI [1]
	Apr. 2002 – Dec. 2002	15,000 bbls/day	US $19.00 – US $21.77	WTI
	Jan. 2002 – Dec. 2002	35,500 bbls/day	US $20.55 – US $26.00	WTI
Brent differential swaps	Jan. 2002 – Dec. 2002	15,000 bbls/day	US $1.38	Dated Brent/WTI
Natural Gas				
Sumas fixed	Jan. 2002 – Oct. 2003	20,000 mmbtu/day	Cdn $2.85	Sumas
Empress – NYMEX differential swap	Jan. 2002 – Oct. 2006	5,500 mmbtu/day	US $0.73	Empress/NYMEX
NYMEX swaps	Jan. 2002 – Oct. 2006	10,000 mmbtu/day	Cdn $2.66	NYMEX
AECO collars	Jan. 2002 – Mar. 2002	190,000 GJ/day	Cdn $3.67 – Cdn $4.58	AECO
	Apr. 2002 – Jun. 2002	130,000 GJ/day	Cdn $3.69 – Cdn $4.48	AECO
	Jan. 2002 – Jun. 2002	100,000 GJ/day	Cdn $3.23 – Cdn $4.00	AECO

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

	Term	Amount ($ millions)	Fixed Rate	Floating Rate
Interest Rate				
Swaps – fixed to floating	Jan. 2002 – Jul. 2004	US $200	6.70%	Libor + 2.09%
	Jan. 2002 – Jul. 2006	US $200	6.70%	Libor + 1.58%
	Jan. 2002 – Jan. 2005	US $100	7.20%	Libor + 3.04% [1]
	Jan. 2002 – Jan. 2007	US $100	7.20%	Libor + 2.23% [1]
	Feb. 2002 – Jan. 2007	US $100	7.20%	Libor + 2.22% [1]

[1] Financial derivative was entered into subsequent to December 31, 2001.

7. SEGMENTED INFORMATION

	THREE MONTHS ENDED DEC 31		YEAR ENDED DEC 31	
	2001	**2000**	**2001**	**2000**
Gross Revenue				
North America	**$ 540.5**	$ 889.4	**$ 2,996.8**	$ 2,905.1
North Sea	**115.2**	125.1	**523.0**	282.8
Offshore West Africa	**5.8**	16.4	**41.6**	34.6
	$ 661.5	$ 1,030.9	**$ 3,561.4**	$ 3,222.5
Net Earnings				
North America	**$ 42.4**	$ 190.5	**$ 596.3**	$ 675.4
North Sea	**15.6**	28.4	**116.9**	95.6
Offshore West Africa	**(4.4)**	5.7	**(9.1)**	14.0
	53.6	224.6	**704.1**	785.0
Dividend on preferred securities, net of tax	**(1.6)**	(1.4)	**(5.9)**	(2.8)
Net Earnings Attributable to Common Shareholders	**$ 52.0**	$ 223.2	**$ 698.2**	$ 782.2
Additions to Property, Plant and Equipment				
North America	**$ 556.6**	$ 68.0	**$ 1,773.2**	$ 965.2
North Sea	**34.3**	29.6	**97.8**	54.9
Offshore West Africa	**43.1**	21.2	**203.9**	39.3
	$ 634.0	$ 118.8	**$ 2,074.9**	$ 1,059.4

Property, plant and equipment and future income taxes payable have been increased by $190.4 million to provide for the tax effect of the acquisition of assets 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 December 31, 2001.

Interest coverage (times)	
Net earnings	8.7 [(1)]
Cash flow	15.6 [(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 December 31, 2001, would be 8.1 and the cash flow coverage ratio for the 12-month period ended December 31, 2001 would be 14.5.

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Standard Time, 11:00 a.m. Eastern Standard Time, on Wednesday, February 27, 2002. The North American conference call number is 1-888-433-1680 and the outside North America conference call number is 1-212-993-0211. 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 March 6, 2002, inclusive. To access postview in North America, dial 1-800-558-5253 and enter the passcode 20339219. Those outside of North America dial 1-416-626-4100 and enter the reservation number 20339133.

FIRST QUARTER 2002 RESULTS AND ANNUAL MEETING

First quarter 2002 results are scheduled for release Wednesday, May 8, 2002. A conference call will be held on that date at 9:00 a.m. Mountain Daylight Time, 11:00 a.m. Eastern Daylight Time.

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.

For further information, please contact:

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