CANADIAN NATURAL RESOURCES LIMITED

ANNUAL INFORMATION FORM

April 12, 2000

DEFINITIONS

The following are definitions of certain abbreviations used in this Annual Information Form:

"**ARTC**" means Alberta Royalty Tax Credit.

"**bbl**" or "**barrel**" means 34.972 Imperial gallons or 42 U.S. gallons.

"**Bcf**" means one billion cubic feet.

"**BPD**" means barrels per day.

"**Canadian Natural**" or **the "Company"** means Canadian Natural Resources Limited, its subsidiaries and their partnerships.

"**gross acres**" means the total number of acres in which the Company holds a working interest or the right to earn a working interest.

"**gross wells**" means the total number of wells in which the Company has a working interest.

"**Mbbls**" means 1,000 barrels.

"**MCF**" means 1,000 cubic feet.

"**MMCF**" means 1,000,000 cubic feet.

"**MCFD**" means 1,000 cubic feet per day.

"**MMCFD**" means 1,000,000 cubic feet per day.

"**NGLs**" means natural gas liquids.

"**net acres**" refers to gross acres multiplied by the percentage working interest therein owned or to be owned by the Company.

"**net wells**" refers to gross wells multiplied by the percentage working interest therein owned or to be owned by the Company.

"**undeveloped land**" or "**non-reserve acreage**" refers to lands on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas.

"**working interest**" means the interest held by the Company in an oil or natural gas property, which interest normally bears its proportionate share of the costs of exploration, development, and operation as well as any royalties or other production burdens.

CURRENCY

Unless otherwise indicated, all sums of money set out in this Annual Information Form are expressed in Canadian dollars.

THE COMPANY

Canadian Natural Resources Limited ("CNRL") was incorporated under the laws of the Province of British Columbia on November 7, 1973, as AEX Minerals Corporation (N.P.L.) and on December 5, 1975 changed its name to Canadian Natural Resources Limited. CNRL was continued under *The Companies Act of Alberta* on January 6, 1982 and was further continued under the *Business Corporations Act* (Alberta) on November 6, 1985. The head, principal and registered office of the Company is located in Calgary, Alberta, Canada at 2000, 425 - 1st Street S.W, T2P 3L8 until April 21, 2000 and thereafter at 2500, 855 – 2nd Street S.W., T2P 4J8.

On January 30, 1995, 579439 Alberta Inc., 579442 Alberta Inc., 586826 Alberta Inc. and 599638 Alberta Inc., all wholly-owned subsidiaries of CNRL, amalgamated to form Cannat Resources Inc. As at December 31, 1996, CNRL had four wholly-owned subsidiaries, Killiam Resources Ltd., Cannat Resources Inc., Sceptre Resources Limited (collectively the "Canadian Subsidiaries") and CM Inc. ("CM"). The Canadian Subsidiaries hold oil and natural gas properties and CM is an inactive United States company. On January 16, 1997, Sceptre Resources Limited was continued under the *Business Corporations Act* (Alberta). On January 30, 1997, Cannat Resources Inc. and Sceptre Resources Limited amalgamated under the *Business Corporations Act* (Alberta), under the name of Cannat Resources Inc. On May 21, 1998 Killiam Resources Ltd. was dissolved.

CNRL also is the managing partner for Canadian Natural Resources (the "Partnership"), a partnership, which holds oil and gas properties of which the partners are CNRL and Cannat Resources Inc. The financial results of the Partnership and all of the subsidiaries with the exception of CM are consolidated with the financial results of the Company as is all of the information contained herein relating to the Company's operations.

BUSINESS AND PROPERTY

Canadian Natural's business is the acquisition of interests in petroleum and natural gas rights and the exploration, development, production, marketing and sale of petroleum and natural gas.

The Company initiates, operates and maintains a large working interest in a majority of the prospects in which it participates. Its objective is to expand its cash flow through the development of its existing oil and natural gas properties and by the discovery and acquisition of new reserves. Currently, the Company's activities are concentrated in the provinces of Alberta, British Columbia and Saskatchewan. The Company has a full complement of management, technical and support staff to pursue these objectives.

On June 13, 1994, the Company issued 6,000,000 Common Shares at a price of $22.00 each.

During 1994, the Company's acquisitions and dispositions program completed 134 transactions from other industry participants for total net consideration of approximately $85 million. This program increased and consolidated the Company's ownership in certain lands and properties, and also extended its holdings in its three primary regions of activity.

On September 14, 1995, the Company issued 6,200,000 Common Shares at a price of $15.50 each.

During 1995, the Company's program of acquisitions and dispositions involved 107 transactions with other industry participants for total net consideration of approximately $24 million. The program had the effect of disposing of non-core assets together with increasing and consolidating its interests in its three principal regions of activity.

On August 15, 1996, pursuant to a Plan of Arrangement, the Company completed the acquisition of all of the issued and outstanding common shares of Sceptre Resources Limited ("Sceptre"). The purchase price was $654.2 million, comprised of $20.0 million in cash, $468.5 million attributable to the issue of 21,792,398 common shares of the Company and $165.7 million by way of assumption of debt including net costs of the acquisition. The acquisition increased and consolidated the Company's holdings in its three operating areas while also providing the Company with three new core areas, all located in the Western Canadian Sedimentary Basin.

During 1996, the Company's program of acquisitions and dispositions involved over 150 transactions with other industry participants for total net consideration of approximately $164.6 million. The program further consolidated and expanded the Company's holdings of oil and natural gas properties in its areas of activity.

During 1997, the Company continued its program of acquisitions and dispositions which further consolidated and expanded the Company's net holdings of oil and natural gas properties in its areas of activity. In carrying out this program the Company completed in excess of 140 transactions with other industry participants and expended a total net amount of $386.3 million. During 1997, the Company issued 750,000 Warrants at $1.00 per warrant. Each warrant entitled the holder to acquire one Common Share of the Company at a price of $36.70 per Common Share until April 9, 1999. None of the Warrants were exercised.

The Company's 1998 acquisition and disposition activities resulted in the completion of 179 transactions and the net expenditure of $63.9 million. In August, 1998, the Company completed the sale of a producing oil and natural gas property located in northeast British Columbia for proceeds of $127.5 million. This property was subject to certain production restrictions pending resolution of an agreement to share a common oil pool. The acquisition of properties was focused on expanding the Company's holdings of producing and undeveloped oil and natural gas properties in its areas of activity (see "Principal Properties").

In the third quarter of 1999 the Company acquired the remaining assets held by the oil business unit of BP Amoco for an acquisition price of $1.05 billion. These assets were comprised of oil producing properties including related facilities, undeveloped lands, an 85 megawatt co-generation plant and gross overriding royalties. The Company acquired, through a plan of arrangement proposed by the Company under the *Companies Creditors' Arrangement Act* (Canada), all of the oil and natural gas properties and related assets held by Blue Range Resource

Corporation for the cash consideration of $235.0 million and the issuance of 500,000 share purchase warrants entitling the holder to acquire, on or before August 16, 2001, one Common Share of the Company at a price of $30.00 per Common Share. In addition, the Company's acquisition and disposition activities resulted in the completion of another 170 transactions at an aggregate net expenditure of $137.3 million.

The Company issued, on May 28, 1999, $125.0 million 6.85% unsecured debentures maturing May 28, 2004 pursuant to a short form shelf prospectus dated February 22, 1999.

The Company issued 10,500,000 common shares at $38.00 per share pursuant to a short form prospectus offering dated August 24, 1999.

ENVIRONMENTAL MATTERS

The Company regularly meets with, and submits to field inspections by the various provincial government departments which are responsible for the regulation of Energy and Utilities, Environment, Lands and Forestry, Fish and Wildlife and various Surface Rights Boards. At present, the Company believes that it meets all requirements of these departments and further meets existing environmental standards and regulations and has included appropriate amounts in its capital expenditure budget to continue to meet current environmental protection requirements. Since these requirements apply to all operators in the western Canadian oil and natural gas industry, it is not anticipated that the Company's competitive position within the industry will be adversely affected. The Company's production facilities are relatively new and the likelihood of major capital expenditures being required to meet future changes is reduced in the near term. The Company has internal procedures designed to ensure that the environmental aspects of new developments are taken into account prior to proceeding.

The costs incurred by the Company for compliance with environmental matters and site restoration costs amount to approximately 1% of the total exploration and development expenditures incurred by the Company in each of the years ended December 31, 1999 and 1998.

A. PRINCIPAL OIL AND NATURAL GAS PROPERTIES

Set forth below is a summary of the principal oil and natural gas properties as at December 31, 1999. The information relating to average production rates and reserve volumes is proportionate to the working interest owned by the Company.

PROPERTY	1999 AVERAGE DAILY PRODUCTION RATES		OIL & NGLs RESERVE VOLUMES (Mbbls)			NATURAL GAS RESERVE VOLUMES (MMCF)		
	OIL & NGLs Mbbls	GAS MMCF	PROVEN RESERVES	PROBABLE RESERVES	TOTAL RESERVES	PROVEN RESERVES	PROBABLE RESERVES	TOTAL RESERVES
Northeastern B.C./ Northwestern Alberta Region	11.2	250	24,502	8,557	33,059	626,463	126,959	753,422
North Central Alberta Region	18.0	303	93,259	13,460	106,719	762,704	133,448	896,152
Eastern Alberta/Western Saskatchewan Region	43.1	28	382,805	58,697	441,502	115,303	21,458	136,761
South Central Alberta Region	7.0	134	21,111	3,663	24,774	555,630	49,376	605,006
Williston Basin Region	6.8	2	23,875	722	24,597	16,711	224	16,935

Northeastern British Columbia/Northwestern Alberta Region

This region comprises lands centred near Fort St. John, British Columbia and straddles the B.C./Alberta border. Similar geological attributes extend from Alberta into British Columbia throughout the more than 50 separate fields located in the region, producing light oil, natural gas liquids and natural gas. The Company holds working interests ranging from 5% to 100% and averaging 78% in 2,238 thousand gross (1,753 thousand net) acres of producing and undeveloped land in the region.

Crude oil reserves are found primarily in the Halfway or lower Halfway formation, while natural gas and associated liquids are found in numerous zones at depths reaching approximately 5,000 vertical feet. In the southern portion of the region the Company owns natural gas producing and undeveloped lands in which the productive zones are at depths up to 10,000 feet. The exploration strategy focuses on comprehensive evaluation through two-dimensional and three-dimensional seismic and targeting economic geological areas close to existing infrastructure. Applying underbalanced, multi-leg horizontal drilling has also proved highly effective in this region. Natural gas production from the region averaged 250 million cubic feet per day for 1999, an increase of 12% from the average of 223 million cubic feet per day produced for 1998. Crude oil and liquids production decreased marginally from 13.9 thousand barrels per day in 1998 to an average of 11.2 thousand barrels per day in 1999. A large proportion of the assets acquired during 1999 through the Plan of Arrangement proposed by the Company for the assets of Blue Range Resource Corporation were located in this region.

During 1999 the Company drilled 10.0 net oil wells, 47.6 net gas wells, and 16.1 net abandoned wells on its lands in this region. The Company held an average 91% working interest in these wells. The Company controls and operates significant production facilities in this region including 10.8 net multi-well oil batteries, 54.3 net gas plants or compressor stations and extensive pipeline and gathering facilities. Interests are also owned in additional facilities operated by other industry participants. All of the facilities are in close proximity to sales facilities.

North Central Alberta Region

Located north and northeast of Edmonton, this region comprises lands located in more than 70 separate natural gas and natural gas liquids producing fields. The Company holds working interests ranging from 10% to 100% and averaging 86% in 4,138 thousand gross (3,574 thousand net) acres of producing and undeveloped land in the region.

Both sweet and slightly sour natural gas reserves are produced from numerous productive horizons at depths up to approximately 3,000 feet. In the southwest portion of the region natural gas liquids and light oil are also encountered at slightly deeper depths. Included in the northern part of this region is the Company's 100% owned holdings at Pelican Lake. These lands contain reserves of lower cost heavy oil. The region continues to be the Company's largest natural gas producing region with natural gas production from the region amounting to 303 million cubic feet per day in 1999 compared to 297 million cubic feet per day in the prior year. Crude oil and liquids production from this region increased to 18.0 thousand barrels per day in 1999 from 10.5 thousand barrels per day in 1998.

During 1999 the Company drilled 76.5 net natural gas wells, 53.0 net oil wells, 5.0 net stratigraphic tests and 24.1 net wells which were abandoned. The Company's average working interest in these wells was in excess of 90%.

At Pelican Lake in the Brintnell area of this region the Company has the major ownership position in the necessary infrastructure, including roads, drilling pads, gathering and sales pipelines, batteries and compressors to ensure future economic development of the large oil pool located on the lands. The Company's holdings in the area were further augmented with the acquisition in 1999 of additional lands and assets included in the acquisition from BP Amoco. With the recovery of oil prices in the second quarter of 1999 the Company re-commenced its horizontal drilling program in this area in the second half of the year.

The Company operates, and owns 61.3 net natural gas plants or compressor stations in the region. In addition, the Company owns and operates 13.2 net oil batteries and has an interest in plants and compressors in the region which are operated by other companies. All of these facilities are in close proximity to existing natural gas sales lines.

Eastern Alberta/Western Saskatchewan Region

The region comprises lands located in a radius of 75 miles from Lloydminster on the Alberta/Saskatchewan border. The Company holds working interests ranging from 12.5% to 100% and averaging 92% in 1,309 thousand gross (1,200 thousand net) acres of producing and undeveloped land in the region.

Reserves of heavy oil (averaging 13° API) and some natural gas are produced through conventional vertical and horizontal well bores from a number of productive horizons up to 2,500 feet deep. After reaching historic lows in the first quarter of 1999 the benchmark WTI price recovered commencing in the second quarter of the year. This, combined with the narrowing of the differential for heavier quality crude oil and reduction in the cost of condensate used for blending resulted in a significant improvement in the price realized for crude oil produced from this region. With the continuance of the Company's overall low operating costs to produce conventional heavy oil, Canadian Natural's netbacks improved significantly throughout the year. Accordingly, in the latter part of the second quarter of the year the Company substantially increased its drilling program in this region.

Included in the assets acquired from BP Amoco was a 100% interest in oil sands leases located in this region at Primrose and Wolf Lake. The lands were producing approximately 30,000 barrels of oil per day using a thermal process. The acquisition also included the infrastructure of gathering systems, a processing plant with a capacity of 60,000 barrels per day and a 50% interest in a co-generation facility capable of producing 85 megawatts of electricity into the power grid. Additional development of the leases will be undertaken in phases over the next ten years.

Daily production from the region increased in 1999 to 43.1 thousand barrels of oil and 28 million cubic feet of natural gas compared to 35.0 thousand barrels of oil and 10 million cubic feet of natural gas in 1998.

During 1999 the Company drilled a total of 122.1 net oil wells, 8.2 net natural gas wells, 1.0 injection well and 5.0 net wells which were abandoned. This compares to only 8.1 net wells in 1998. In this region, the Company owns and operates 8.7 net oil batteries and 5.0 net compressor stations as well as the related gathering and other processing facilities. A successful Steam Assisted Gravity Drainage heavy oil project, in which the Company holds a 50% interest, is also in operation in the Saskatchewan portion of this region.

South Central Alberta Region

This region, located east and southeast of Calgary, contains lands with similar geologic features as the Company's North Central Alberta region. The region was added to the Company's focused areas of operation in mid 1996 with the acquisition of Sceptre Resources Limited. The Company holds interests ranging from 10% to 100% and averaging 86% in 849 thousand gross (731 thousand net) acres of producing and undeveloped land in the region.

Reserves of natural gas, condensate and light and medium gravity crude oil are contained in numerous productive horizons at depths up to 5,000 feet. New techniques are being used to increase the recovery factor in existing pools of oil and natural gas located on the lands. The Company's share of production averaged 7.0 thousand barrels of oil and liquids per day and 134 million cubic feet of natural gas per day in 1999. Average daily production realized by the Company in 1998 amounted to 9.2 thousand barrels of oil and liquids and 132 million cubic feet of natural gas.

During 1999 the Company drilled a total of 13.2 net oil wells, 325.3 net natural gas wells, 2.0 injection wells and 4.0 net abandoned wells in this region. The number of natural gas wells drilled by the Company was significantly increased over the prior year and consisted of shallow wells with long life but lower productivity per well. The wells were predominantly in areas where the Company already has gathering and processing facilities. The Company operates 25.9 net oil batteries and 25.7 net natural gas plants or compressor stations in the region with working interests ranging from 10% to 100%. All of the facilities are located in areas with close access to natural gas sales lines.

Williston Basin Region

The Williston Basin is located in Southeastern Saskatchewan with lands spilling over into Manitoba and North Dakota. This region was owned by Sceptre Resources Limited and acquired by the Company in mid 1996 with the acquisition of Sceptre. The Company holds interests ranging from 35% to 100% and averaging 94% in 538 thousand gross (505 thousand net) acres of producing and undeveloped lands in the region.

The region produces primarily light sour crude oil from as many as seven productive horizons found at depths up to 8,000 feet. During 1999 production to the Company averaged 6.8 thousand barrels per day, compared to the average 1998 production of 6.3 thousand barrels of oil per day.

A total of 13.2 net oil wells and 0.9 net abandoned wells were drilled by the Company in 1999 with an average 78% working interest. These wells included a number of horizontal wells that confirmed the potential of known pools of oil in the Company's lands. Appropriate production facilities, including 30.7 net oil batteries and gathering systems, are owned by the Company in close proximity to sales facilities.

B. PETROLEUM AND NATURAL GAS RESERVES

Canadian Natural retains Sproule Associates Limited ("Sproule"), independent petroleum engineering consultants, to evaluate the Company's proven and probable oil and natural gas reserves and prepare an Evaluation Report on the Company's total reserves ("Sproule Evaluation Report"). Sproule has been retained by the Company for the past 10 years and each year has prepared an Evaluation Report on the majority of the Company's total reserve base. For the year ended December 31, 1999 Sproule's Evaluation Report covered 97% of the Company's reserves (made up of 81% of the Company's reserves from the January, 2000 evaluation, including the updated August, 1999 evaluation of the acquired BP Amoco properties, plus 16% of the Company's reserves from a computer recalculation of the Sproule reviewed January, 1999 evaluation) with the Company internally evaluating the remaining 3% of the Company's reserves, which are generally comprised of reserves in properties not currently strategic to the Company's core business areas.

In 1999, the Board of Directors of the Company established a Reserve Committee which has met with Sproule and carried out independent due diligence procedures with Sproule as to the Company's reserves.

The following tables summarize the evaluations of reserves and estimated future net production revenues at January 1, 2000.

The estimated future net production revenue figures contained in the following tables take into account the effect of ARTC, processing revenues and corporate Capital Gas Cost Allowance but are prepared prior to consideration of income taxes and indirect costs, such as overhead, interest and administrative expenses, and are not to be construed as a representation of the fair market value of the properties to which they relate. The present worth of the probable reserves evaluated by Sproule has been reduced to account for risk. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized in the notes to the following tables.

Oil and Natural Gas Reserves
Escalated Prices and Costs

	Oil and Natural Gas Liquids Gross (Mbbls)	Oil and Natural Gas Liquids Net (Mbbls)	Natural Gas Gross (MMCF)	Natural Gas Net (MMCF)
Proven developed producing	291,807	266,503	1,595,772	1,311,556
Proven developed non-producing	37,739	32,598	189,098	154,434
Proven undeveloped	224,010	202,892	398,204	304,382
Total proven reserves	553,556	501,993	2,183,074	1,770,372
Probable reserves	86,368	73,167	364,243	293,658
Total proven and probable reserves	639,924	575,160	2,547,317	2,064,030

Estimated Future Net Revenues
Escalated Prices and Costs

	Undiscounted	Discounted at 10%	Discounted at 15%	Discounted at 20%
	(Thousands of Dollars)			
Proven developed producing	7,853,703	4,706,006	3,987,402	3,480,563
Proven developed non-producing	824,869	475,227	388,903	327,682
Proven undeveloped	3,138,104	1,577,642	1,204,569	951,413
Total proven reserves	11,816,676	6,758,875	5,580,874	4,759,658
Probable reserves	936,527	407,365	304,309	238,075
Total proven and probable reserves	12,753,203	7,166,240	5,885,183	4,997,733

Oil and Natural Gas Reserves
Constant Prices and Costs

	Oil and Natural Gas Liquids		Natural Gas	
	Gross	Net	Gross	Net
	(Mbbls)		(MMCF)	
Proven developed producing	291,865	266,145	1,595,767	1,312,141
Proven developed non-producing	37,756	32,588	189,097	154,274
Proven undeveloped	224,007	202,195	398,170	304,308
Total proven reserves	553,628	500,928	2,183,034	1,770,723
Probable reserves	86,391	72,958	364,223	293,934
Total proven and probable reserves	640,019	573,886	2,547,257	2,064,657

Estimated Future Net Revenues
Constant Prices and Costs

	Undiscounted	Discounted at 10%	Discounted at 15%	Discounted at 20%
		(Thousands of Dollars)		
Proven developed producing	7,280,768	4,598,747	3,934,744	3,456,467
Proven developed non-producing	770,577	460,327	380,309	322,679
Proven undeveloped	2,999,565	1,568,246	1,212,867	967,988
Total proven reserves	11,050,910	6,627,320	5,527,920	4,747,134
Probable reserves	817,702	381,387	289,723	229,468
Total proven and probable reserves	11,868,612	7,008,707	5,817,643	4,976,602

NOTES

1. "Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by the Company before deduction of royalties payable to others.

2. "Net" reserves means the Company's gross reserves less all royalties payable to others.

3. "Proven developed producing" reserves are those proven reserves that are presently being produced from completion intervals open for production in existing wells with existing equipment and operating methods.

4. "Proven developed non-producing" reserves are those proven reserves which are currently not being produced but do exist in completed intervals but not producing in existing wells, behind casing in existing wells or at minor depths below the present bottom of existing wells. These proven reserves are expected to be produced through the existing wells in the predictable future and are classified as proven developed since the cost of making such reserves available for production is relatively small, compared to the cost of a new well.

5. "Proven undeveloped" reserves are those proven reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where relatively major expenditures are required for the completion of these wells or for the installation of processing and gathering facilities prior to the production of these reserves. Reserves on undrilled acreage are limited to those drilling units offsetting productive wells that are reasonably certain of production when drilled.

6. "Proven" reserves are those quantities of crude oil, natural gas and natural gas by-products, which, upon analysis of geologic and engineering data, appear with a high degree of certainty to be recoverable at commercial rates in the future from known oil and gas reservoirs under presently anticipated economic and operating conditions for the escalated prices and costs case and under existing economic and operating conditions for the constant prices and costs case.

7. "Probable" reserves are those reserves which may be recoverable as a result of the beneficial effects which may be derived from the future institution of some form of pressure maintenance or other secondary recovery method, or as a result of a more favourable performance of the existing recovery mechanism than that which would be deemed proven at the present time, or those reserves which may reasonably be assumed to exist because of geophysical or geological indications and drilling done in regions which contain proven reserves. **The estimated present worth of the probable reserves set forth above have been risk weighted by 50 percent to account for the probability of obtaining production from such reserves.**

8. All values are shown in Canadian dollars.

9. The escalated price and cost case assumes the continuance of current laws and regulations, and any increases in wellhead selling prices also take inflation into account. Sales prices are based on reference prices as detailed below and adjusted for quality of reserves and contract conditions. Subsequent to 2011, reference prices and costs are escalated at 1.5% per year. Future oil price forecasts were based on Sproule's October 1, 1999 oil and liquids pricing model while future natural gas price forecasts were provided by the Company based on existing and forecasted future gas marketing arrangements entered into by the Company, which is consistent with year end evaluations of prior years.

The principal crude oil and natural gas price forecasts used in the Sproule Report are as follows:

	NATURAL GAS			OIL		
YEAR	Alberta Blended Price $CDN/MMBTU	British Columbia Blended Price $CDN/ MMBTU	Henry HUB $US/MMBTU	WTI @ Cushing (i) $US/bbl	Edmonton Par Price (ii) $CDN/bbl	Hardisty Par Price $Cdn./bbl
2000	3.05	3.04	2.56	20.00	27.51	20.01
2001	3.04	3.04	2.53	20.30	27.13	19.14
2002	3.14	3.11	2.62	20.60	27.15	18.64
2003	3.24	3.18	2.73	20.91	27.56	19.04
2004	3.33	3.28	2.82	21.23	27.98	19.43
2005	3.40	3.36	2.90	21.55	28.41	19.83
2006	3.47	3.46	2.96	21.87	28.84	20.24
2007	3.55	3.52	3.03	22.20	29.28	20.66
2008	3.62	3.65	3.10	22.53	29.72	21.08
2009	3.70	3.82	3.17	22.87	30.17	21.51
2010	3.78	3.88	3.26	23.21	30.63	21.94
2011	3.83	3.94	3.36	23.56	31.09	22.27

(i) "WTI @ Cushing" refers to the price of West Texas Intermediate crude oil at Cushing, Oklahoma.

(ii) "Edmonton Par Price" refers to the price of light gravity (40^{o} API), low sulphur content crude oil at Edmonton, Alberta.

10. Product prices in the constant price evaluation are those used for 2000 in the escalated price evaluation. The constant price assumptions assume the continuance of current laws, regulations and operating costs in effect on the date of the Sproule Report. Product prices have not been escalated beyond 2000. In addition, operating and capital costs have not been increased on an inflationary basis.

11. The estimated total capital costs net to the Company necessary to achieve the estimated future net proven and probable production revenues are:

	Escalated Price Case ($) (Thousands)	Constant Price Case ($) (Thousands)
2000	210,514	210,514
2001	194,946	192,065
2002	171,319	166,293
2003	36,309	34,723
2004	85,498	80,555
2005	35,783	33,216
2006	29,173	26,680
2007	14,260	12,849
Thereafter	34,176	28,729
	811,978	785,624

12. Estimated future net revenue includes the Alberta Royalty Tax Credit which, in the escalated price case, is estimated to be $19,119 undiscounted and $6,917, $5,239 and $4,248 discounted at 10%, 15% and 20% respectively. In the constant price case, the Alberta Royalty Tax Credit is estimated to be $28,259 undiscounted and $8,569, $6,119 and $4,755 discounted at 10%, 15% and 20% respectively.

13. Estimated future net revenue includes the value of the Company's Corporate Capital GCA - Alberta Crown Credits which, in the escalated price case is estimated to be $42,714 undiscounted and $33,548, $30,406 and $27,867 discounted at 10%, 15% and 20%

respectively. In the constant price case the value of this credit is estimated to be $42,714 undiscounted and $33,548, $30,406 and $27,867 discounted at 10%, 15% and 20% respectively.

14. Net production revenue is income derived from the sale of net reserves of oil, natural gas and NGLs, less all capital costs, production taxes, and operating costs and before provision for income taxes and administrative overhead costs.

15. The Sproule Report was based upon data supplied by the Company with respect to quality and heating value adjustments, interests owned, royalties payable, operating costs and contractual commitments. No field inspection was conducted.

C. RECONCILIATION OF CHANGES IN RESERVES

The following table summarizes the changes in reserves during the past year:

	CRUDE OIL AND NGLs (Mbbls)			NATURAL GAS (MMCF)		
	PROVEN	PROBABLE	TOTAL	PROVEN	PROBABLE	TOTAL
Balance as at January 1, 1999	287,005	97,188	384,193	1,905,194	310,547	2,215,741
Discoveries and Purchases	289,223	408	289,631	564,941	67,567	632,508
Property disposals	(110)	(45)	(155)	(19,883)	(7,185)	(27,068)
Production	(31,664)		(31,664)	(263,165)		(263,165)
Adjustments of prior estimates	9,102	(11,183)	(2,081)	(4,013)	(6,686)	(10,699)
Balance as at January 1, 2000	553,556	86,368	639,924	2,183,074	364,243	2,547,317

D. OIL AND NATURAL GAS PRODUCTION

Canadian Natural's working interest share of oil, NGLs and natural gas production is summarized in the following table:

	YEAR ENDED DECEMBER 31				
	1999	1998	1997	1996	1995
Daily Production Oil and NGLs (BPD)	86,750	75,744	70,619	37,399	16,836
Natural Gas (MMCFD)	721.0	672.6	625.5	499.3	304.8
Annual Production					
Oil and NGLs (Mbbls)	31,664	27,646	25,776	13,688	6,145
Natural Gas (Bcf)	263.2	245.5	228.3	182.7	111.2

E. DRILLING ACTIVITY

The following table sets forth the gross and net wells in which Canadian Natural has participated for the period indicated:

	YEAR ENDED DECEMBER 31									
	1999		1998		1997		1996		1995	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Natural Gas	481	457.6	216	193.2	237	199.6	134	128.1	89	73.9
Oil	229	211.5	120	106.5	486	442.9	228	208.9	122	112.5
Injection/Strat Tests	11	8.9	20	15.5	2	1.5	2	1.0	-	-
Dry	54	49.3	48	42.7	75	67.0	64	62.9	24	22.3
Total	775	727.3	404	357.9	800	711.0	428	400.9	235	208.7

F. CAPITAL EXPENDITURES

Costs incurred by Canadian Natural in respect of its programs of acquisition and disposition, and exploration and development of oil and gas properties, are summarized in the following table:

	YEAR ENDED DECEMBER 31				
	1999	1998	1997	1996	1995
	($Millions)				
Corporate acquisition	-	-	-	654.2	-
Net property acquisitions	1,422.3	63.9	386.3	164.6	24.0
Seismic and geological evaluation	17.9	17.2	38.9	32.5	19.1
Land acquisition and retention	46.2	39.0	98.3	55.6	30.7
Well drilling, completion and equipping	274.8	255.2	350.7	163.8	92.2
Pipeline and production facilities	143.2	205.7	240.3	130.1	71.5
Reserve replacement expenditures	1,904.4	581.0	1,114.5	1,200.8	237.5
Head office equipment	2.7	3.3	4.6	2.8	1.3
Projects under construction	(6.5)	25.4	-	-	-
Total	1,900.6	609.7	1,119.1	1,203.6	238.8

G. NON-RESERVE ACREAGE

The following table summarizes Canadian Natural's working interest holdings in non-reserve acreage in the Western Canadian Sedimentary Basin as at December 31, 1999:

	Gross Acres	Net Acres
Alberta	4,036,663	3,582,176
British Columbia	1,325,088	1,026,692
Saskatchewan	517,735	481,158
Manitoba	166,510	164,415
North Dakota, USA	185,116	185,116
Total	6,231,112	5,439,557

SELECTED FINANCIAL INFORMATION

The following table summarizes the consolidated financial statements of Canadian Natural. The Company follows the full cost method of accounting for oil and gas operations.

	YEAR ENDED DECEMBER 31				
	1999	1998	1997	1996	1995
	($ thousands except per share information)				
Net revenues (after royalties)	1,098,886	760,878	768,722	532,347	245,419
Cash flow from operations	723,469	444,224	503,012	359,741	153,621
Per Common Share	6.96	4.47	5.13	4.32	2.22
Net earnings	200,200	59,017	111,293	95,026	42,401
Per Common Share	1.93	0.59	1.14	1.14	0.61
Total assets	4,850,850	3,247,418	2,931,143	2,062,633	900,429
Total long-term debt	2,156,850	1,425,479	1,136,276	588,021	237,700

	1999 THREE MONTHS ENDED			
	MARCH 31	JUNE 30	SEPT. 30	DEC. 31
	($ thousands except per share information)			
Net revenues (after royalties)	174,476	198,943	337,412	388,055
Net earnings	10,353	23,496	70,499	95,852
Per Common Share	0.10	0.24	0.69	0.90

	1998 THREE MONTHS ENDED			
	MARCH 31	JUNE 30	SEPT. 30	DEC. 31
	($ thousand except per share information)			
Net revenues (after royalties)	172,430	179,574	197,511	211,363
Net earnings	8,351	6,230	20,891	23,545
Per Common Share	0.08	0.07	0.21	0.23

MARKET FOR CANADIAN NATURAL'S SECURITIES

Canadian Natural's common shares are listed and posted for trading on The Toronto Stock Exchange under the symbol CNQ.

DIVIDEND HISTORY

Dividends have never been paid on the common shares of Canadian Natural and at the present time it is the policy of the Company not to declare regular dividends on its common shares. Such policy is under periodic review by the Board of Directors and is subject to change at any time depending upon the earnings of the Company, its financial requirements and other factors existing at the time.

DIRECTORS AND OFFICERS

The names, municipalities of residence, offices held with the Company and principal occupations of the directors and officers of the Company as at December 31, 1999 are set forth below.

Name	**Position Presently Held**	**Principal Occupation During Past 5 Years**
N. Murray Edwards Calgary, Alberta	Director	President, Edco Financial Holdings Ltd. (Private Investment Company)
James T. Grenon Calgary, Alberta	Director	Managing Director, TOM Capital Associates Inc. (Private Investment Company) since August, 1995, prior thereto President, Grencorp Management Inc. (Private Investment Company)
John G. Langille Calgary, Alberta	President and Director	Officer of the Company
Keith A.J. MacPhail Calgary, Alberta	Director	Chairman and President, Bonavista Petroleum Ltd. since November, 1997; prior thereto Officer of the Company
Allan P. Markin Calgary, Alberta	Chairman and Director	Chairman of the Company
James S. Palmer Calgary, Alberta	Director	Chairman, Burnet, Duckworth & Palmer (Barristers & Solicitors)
Dr. Eldon R. Smith Calgary, Alberta	Director	Professor and Former Dean, Faculty of Medicine, The University of Calgary

Name	Position Presently Held	Principal Occupation During Past 5 Years
Brian L. Illing Calgary, Alberta	Senior Vice-President, Exploration	Officer of the Company
Steve W. Laut Calgary, Alberta	Senior Vice-President, Operations	Officer of the Company since January, 1995; prior thereto Exploitation Manager and Senior Exploitation Engineer of the Company.
Gregory G. Adams Calgary, Alberta	Vice-President, Finance	Officer of the Company since February, 1998; prior thereto, Controller of the Company
Réal M. Cusson Calgary, Alberta	Vice-President, Marketing	Officer of the Company since August, 1995; prior thereto, Vice-President, Marketing, Conwest Exploration Company Limited since September, 1993; prior thereto Manager, Direct Marketing, Natural Gas, Shell Canada Limited.
Allen M. Knight Calgary, Alberta	Vice-President, Corporate Development & Land	Officer of the Company
Tim S. McKay Calgary, Alberta	Vice-President, Production	Officer of the Company since September, 1996; prior thereto Production Manager of the Company.
Lyle G. Stevens Calgary, Alberta	Vice-President, Exploitation	Officer of the Company since October, 1997; prior thereto Exploitation Engineer of the Company since April, 1995;
Gordon M. Adams Calgary, Alberta	Secretary	Partner, Parlee McLaws (Barristers and Solicitors)

All directors stand for election at each Annual General Meeting of CNRL shareholders. The 1999 Annual General Meeting is scheduled for May 11, 2000. The Audit Committee, pursuant to section 165(1) of the *Business Corporations Act (Alberta)*, is composed of Messrs. Edwards, Grenon, Markin and Palmer.

As at December 31, 1999, the directors and senior officers of the Company, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, in the aggregate, approximately 7% of the total outstanding common shares (approximately 8% after the exercise of options pursuant to the Company's Stock Option Plan).

ADDITIONAL INFORMATION

Additional information, including Directors' and Executive Officers' remuneration, principal holders of Canadian Natural's securities and options to purchase Canadian Natural's securities, and interest of insiders in material transactions is contained in Canadian Natural's Notice of Annual General Meeting and Information Circular dated March 30, 2000 in connection with the Annual General Meeting of Shareholders of Canadian Natural held on May 11, 2000 which information is incorporated herein by reference. Additional financial information and discussion of the affairs of the Company and the business environment in which the Company operates is provided in the Company's comparative Consolidated Financial Statements and Management Discussion and Analysis for the most recently completed fiscal year ended December 31, 1999 found on pages 41 to 49 and 29 to 38, respectively, and on pages 50 and 51 of the 1999 Annual Report to the Shareholders, which information is incorporated herein by reference.

Canadian Natural shall provide to any person, upon request to the Secretary of Canadian Natural:

(a) when securities of Canadian Natural are in the course of distribution pursuant to a short form prospectus or a preliminary short form prospectus has been filed in respect of a distribution of its securities,

  (i) one copy of the Annual Information Form of Canadian Natural, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in the Annual Information Form,

  (ii) one copy of the comparative financial statements of Canadian Natural for its most recently completed financial year together with the accompanying report of the auditor and one copy of any interim financial statements of the issuer subsequent to the financial statements for its most recently completed financial year,

  (iii) one copy of the information circular of Canadian Natural in respect of its most recent annual meeting of shareholders that involved the election of directors or one copy of any annual filing prepared in lieu of that information circular, as appropriate, and

  (iv) one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under (i) to (iii) above; or

(b) at any other time, one copy of any other documents referred to in (a)(i), (ii) and (iii) above, provided Canadian Natural may require the payment of a reasonable charge if the request is made by a person who is not a security holder of the issuer.

For additional copies of this AIF and the materials listed in the preceding paragraphs, please contact:

Corporate Secretary of the Corporation at:
2500, 855 – 2nd Street S.W.
Calgary, Alberta T2P 4J8