CANADIAN NATURAL RESOURCES LTD
Form 40-F
April 17, 2003

U.S. SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 40-F

[_] REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

OR

[X] ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2002

Commission File No. 1-8795

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

| CANADA | 1311 | NOT APPLICABLE |
|---|---|---|
| Province or other jurisdiction of incorporation or organization) | (Primary Standard Industrial Classification Code Number) | (I.R.S. Employer Identifi Number) |

2500, 855 - 2ND STREET S.W., CALGARY, ALBERTA, CANADA T2P 4J8
(403) 517-7345
(Address and telephone number of Registrant's principal executive offices)

CT CORPORATION SYSTEM, 111-8TH AVENUE, NEW YORK, NEW YORK 10011, (212) 894-8940
(Name, address (including zip code) and telephone number (including area code) of Agent for Service of the Registrant in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

| TITLE OF EACH CLASS | NAME OF EACH EXCHANGE ON WHICH REGISTERED |
|---|---|
| Common Shares, no par value | New York Stock Exchange |

Securities registered or to be registered pursuant to Section 12(g) of the Act:

None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: None

For annual reports, indicate by check mark the information filed with this form:

[X] Annual information form [X] Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

At December 31, 2002, 133,775,558 Common Shares of Canadian Natural Resources Limited were issued and outstanding. At December 31, 2002, no Class 1 Preferred Shares of Canadian Natural Resources Limited were issued and outstanding.

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the file number assigned to the Registrant in connection with such Rule. YES [_] NO [X]

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES [X] NO [_]

## PRIOR FILINGS MODIFIED AND SUPERSEDED

The Registrant's Annual Report on Form 40-F for the year ended December 31, 2002, at the time of filing with the Securities and Exchange Commission (the "Commission"), modifies and supersedes all prior documents filed pursuant to Sections 13, 14 and 15(d) of the Exchange Act for purposes of any offers or sales of any securities after the date of such filing pursuant to any Registration Statement under the Securities Act of 1933 of the Registrant which incorporates by reference such Annual Report. The documents (or portions thereof) identified under the heading "Documents Filed as Part of This Report" below as forming part of this Form 40-F are incorporated by reference into the Registration Statement on Form F-9 No. 333-98063 as exhibits thereto.

## CONSOLIDATED AUDITED ANNUAL FINANCIAL STATEMENTS AND MANAGEMENT'S DISCUSSION AND ANALYSIS

For the purposes of this Annual Report on Form 40-F, only pages 32 through 70 of the Registrant's 2002 Annual Report referred to below shall be deemed filed, and the balance of such 2002 Annual Report, except as it may be otherwise specifically incorporated by reference in the Registrant's Annual Information Form, shall be deemed not filed with the Commission as part of this Annual Report on Form 40-F under the Exchange Act.

A. Audited Annual Financial Statements

For consolidated audited financial statements, including the report of independent chartered accountants with respect thereto, see pages 50 through 70 of the Registrant's 2002 Annual Report, which pages are attached hereto and included herein. For a reconciliation of important differences between Canadian and United States generally accepted accounting principles, see Note 16 - Differences Between Canadian and United States Generally Accepted Accounting Principles on pages 68 through 70 of such 2002 Annual Report.

B. Management's Discussion and Analysis

For management's discussion and analysis, see pages 32 through 49 of the Registrant's 2002 Annual Report, which pages are attached hereto and included herein.

## CONTROLS AND PROCEDURES

Within the 90-day period prior to the filing of this report, an evaluation was carried out under the supervision of and with the participation of the Registrant's management, including the Chief Executive Officer and Chief

Financial Officer, of the effectiveness of the Registrant's disclosure controls and procedures (as defined in Rule 13a-14(c) under the Exchange Act). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective to ensure that material information required to be disclosed by the Registrant in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Commission's rules and forms.

No significant changes were made in the Registrant's internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

It should be noted that any system of controls, however well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the system are met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events. Because of these and other inherent limitations of control systems, there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions, regardless of how remote.

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UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

B. Consent to Service of Process

The Registrant has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

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SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this Annual Report on Form 40-F to be signed on its behalf by the undersigned, thereto duly authorized, in the City of Calgary, Province of Alberta, Canada.

CANADIAN NATURAL RESOURCES LIMITED
(Registrant)

By: /s/ John G. Langille
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Name: John G. Langille
Title: President

Date: April 15, 2003

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CERTIFICATIONS

I, John G. Langille, President, certify that:

1. I have reviewed this annual report on Form 40-F of Canadian Natural Resources Limited;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (and persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: April 15, 2003

/s/ John G. Langille
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Name: John G. Langille
Title: President

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CERTIFICATIONS

I, Douglas A. Proll, Senior Vice President, Finance, certify that:

1. I have reviewed this annual report on Form 40-F of Canadian Natural Resources Limited;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (and persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: April 15, 2003

/s/ Douglas A. Proll

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Name: Douglas A. Proll
Title: Senior Vice President, Finance



DOCUMENTS FILED AS PART OF THIS REPORT

1. Annual Information Form of the Registrant for the year ended December 31, 2002.

2. Management's Discussion and Analysis of the Registrant for the year ended December 31, 2002.

3. Audited Consolidated Financial Statements of the Registrant as of December 31, 2002 and for each of the three years then ended (Note 16 to the Audited Consolidated Financial Statements of the Registrant relates to differences between Canadian and United States Generally Accepted Accounting Principles).

EXHIBITS

99.1 Consent of PricewaterhouseCoopers LLP, independent chartered accountants.

99.2 Consent of Sproule Associates Limited, independent petroleum consultants.

99.3 Certificate Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

99.4 Certificate Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.



DOCUMENT 1

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CANADIAN NATURAL RESOURCES LIMITED

ANNUAL INFORMATION FORM

APRIL 14, 2003

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CURRENCY

Unless otherwise indicated, all dollar figures stated in this Annual Information Form represent Canadian dollars.



DEFINITIONS

The following are definitions of selected 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.

"BBLS/D" means barrels per day.

"CANADIAN NATURAL RESOURCES LIMITED", "CANADIAN NATURAL", "CNRL" or "COMPANY" means Canadian Natural Resources Limited and includes, where applicable, reference to subsidiaries of and partnership interests held by Canadian Natural Resources Limited and its subsidiaries.

"FPSO" means floating production, storage and off-take vessel.

"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 one thousand barrels.

"MCF" means one thousand cubic feet.

"MCF/D" means one thousand cubic feet per day.

"MMBBLS" means one million barrels.

"MMBTU" means one million British thermal units.

"MMCF" means one million cubic feet.

"MMCF/D" means one million 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.

"SAGD" means steam-assisted gravity drainage.

"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 crude oil and natural gas.

"WORKING INTEREST" means the interest held by the Company in a crude 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.

"WTI" means West Texas Intermediate.

Natural gas is converted to oil equivalent at the rate of six thousand cubic feet equals one barrel of oil equivalent.



## SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this document or incorporated herein by reference may constitute "forward-looking statements" within the meaning of the United States Private Litigation Reform Act of 1995. These forward-looking statements can generally be identified as such because of the context of the statements including words such as the Company "believes", "anticipates", "expects", "plans", "estimates" or words of a similar nature.

The forward-looking statements are based on current expectations and are subject to known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements of the Company, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others: the general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; the foreign currency exchange rates; the economic conditions in the countries and regions in which the Company conducts business; the political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; the industry capacity; the ability of the Company to implement its business strategy, including exploration and development activities; the impact of competition, availability and cost of seismic, drilling and other equipment; the ability of the Company to complete its capital programs; the ability of the Company to transport its products to market; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the operating hazards and other difficulties inherent in the exploration for and production and sale of oil and natural gas; the availability and cost of financing; the success of exploration and development activities; the timing and success of integrating the business and operations of acquired companies; the production levels; the uncertainty of reserve estimates; the actions by governmental authorities; the government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations); the site restoration costs; and other circumstances affecting revenues and expenses. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors, and management's course of action would depend upon its assessment of the future considering all information then available.

Statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future.

Readers are cautioned that the foregoing list of important factors is not exhaustive. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. The Company assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.



## THE COMPANY

Canadian Natural Resources Limited 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 2500, 855 - 2nd Street S.W., T2P 4J8.

CNRL formed a wholly owned subsidiary, CanNat Resources Inc. ("CanNat") in January 1995. Pursuant to a Plan of Arrangement the Company acquired all of the outstanding shares of Sceptre Resources Limited ("Sceptre") in September 1996 and in January 1997, Sceptre and CanNat amalgamated pursuant to the BUSINESS CORPORATIONS ACT (Alberta) under the name CanNat Resources Inc.

Pursuant to an Offer to Purchase all of the outstanding shares, the Company completed the acquisition of Ranger Oil Limited, including its subsidiaries, ("Ranger") in July 2000. On October 1, 2000 Ranger Oil Limited and the Company amalgamated pursuant to the BUSINESS CORPORATIONS ACT (Alberta) under the name Canadian Natural Resources Limited.

Pursuant to a Plan of Arrangement the Company acquired all of the outstanding shares of Rio Alto Exploration Ltd. ("RAX") in July 2002. On January 1, 2003 RAX and the Company amalgamated pursuant to the BUSINESS CORPORATIONS ACT (Alberta) under the name Canadian Natural Resources Limited.

The material operating subsidiaries of the Company, each of which is directly or indirectly wholly-owned, and their jurisdiction of incorporation are as follows:

| NAME OF COMPANY | JURISDICTION OF INCORPORATION |
|---|---|
| CanNat Resources Inc. | Alberta |
| CNR International (U. K.) Developments Limited | England |
| CNR International (U. K.) Limited | England |
| CNR International Cote d'Ivoire SARL | Cote d'Ivoire |
| Renata Resources Inc. | Alberta |

CNRL as the managing partner and CanNat are the partners of Canadian Natural Resources, a general partnership. Canadian Natural Resources as the managing partner and Renata Resources Inc. are partners of Rio Alto Exploration, a general partnership. The two partnerships hold the Canadian crude oil and natural gas properties of CNRL. CNRL also has a 15 per cent interest in Cold Lake Pipeline Ltd., which is the General Partner of Cold Lake Pipeline Limited Partnership of which CNRL has a 14.7 per cent interest.

The consolidated financial statements of CNRL include the accounts of the Company and all of its subsidiaries and partnerships.

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GENERAL DEVELOPMENT OF THE BUSINESS

CNRL's business is the acquisition of interests in crude oil and natural gas rights and the exploration, development, production, marketing and sale of crude oil and natural gas.

The Company initiates, operates and maintains a large working interest in a majority of the prospects in which it participates. CNRL's objective is to increase cash flow and earnings through the development of its existing crude oil and natural gas properties and through the discovery and acquisition of new reserves. The Company's principal regions of crude oil and natural gas operations are in the Western Canadian Sedimentary Basin, the United Kingdom (the "UK") sector of the North Sea and offshore West Africa. The Company has a full complement of management, technical and support staff to pursue these objectives. As at December 31, 2002 the Company had 1,448 full time employees in North America and 174 full time employees in its international operations.

In July 2000, the Company acquired 100 per cent of Ranger for a total purchase price of $1,687.3 million, comprised of $722.8 million in cash, $358.0 million attributable to the issue of 7,602,068 common shares of the Company, and the assumption of $376.6 million of debt, $118.3 million of preferred securities and $111.6 million of working capital deficiency. Ranger held a portfolio of producing and non-producing crude oil and natural gas properties in the Western Canadian Sedimentary Basin, the United States Gulf Coast, the UK sector of the North Sea, and offshore West Africa. The Offer to Purchase dated June 19, 2000 offered $8.25 cash per common share for each Ranger common share subject to an aggregate maximum of $650.0 million cash and to proration as described in the Offer to Purchase; or 0.175 common shares of CNRL, subject to an aggregate maximum of 10 million common shares and to proration as described in the Offer to Purchase. Pursuant to the Offer to Purchase, 7,602,068 common shares of CNRL were issued.

During 2000, the Company completed 170 transactions in the normal course to acquire additional interests in crude oil and natural gas properties at an aggregate expenditure of $278.2 million. These properties are located in the Company's principal operating regions and are comprised of producing and non-producing leases together with related facilities. In addition, the Company disposed of non-operated Canadian properties owned by Ranger, not located in the Company's core regions, for proceeds of $128.0 million.

On February 24, 2000, the Company issued $125.0 million 7.40 per cent unsecured debentures maturing March 1, 2007 pursuant to a short form shelf prospectus dated February 22, 1999.

In 2001, the Company completed 121 transactions in the normal course to acquire additional interests in crude oil and natural gas properties at an aggregate expenditure of $582.2 million. These properties are located in the Company's principal operating regions and are comprised of producing and non-producing leases together with related facilities. In addition, the Company disposed of non-operated properties not located in the Company's core regions for proceeds of $63.0 million, including a large portion of the properties acquired with Ranger in the United States Gulf Coast.

On July 24, 2001, the Company issued US $400.0 million of 10 year 6.70per cent unsecured notes maturing July 15, 2011 pursuant to a prospectus supplement dated July 19, 2001 to the short form shelf prospectus dated July 6, 2001. Pursuant to a prospectus supplement dated January 15, 2002 to the short form shelf prospectus dated July 6, 2001, the Company issued on



January 23, 2002, US $400.0 million 30 year 7.20per cent unsecured notes maturing January 15, 2032.

In July 2002, pursuant to the terms of a Plan of Arrangement, the Company acquired 100 per cent of RAX. The total purchase price was $2,393.2 million, comprised of $850.0 million in cash, $522.4 million attributable to the issue of 10,008,218 common shares of the Company, and the assumption of $936.3 million of debt and $84.5 million of working capital deficiency. The acquisition provided the Company with a new core region for natural gas exploration and exploitation activities in Northwest Alberta. The RAX properties include approximately 2.9 million net acres of undeveloped lands and will provide additional opportunities for the Company to increase its production and reserves of natural gas and natural gas liquids. The acquisition added additional production which averaged 376 million cubic feet per day of natural gas and 11 thousand barrels per day of crude oil and natural gas liquids during the second half of 2002 and 2-D and 3-D seismic of 57,820 kilometres and 14,565 square kilometres respectively. Future exploration and development projects will take advantage of the large undeveloped land base, high quality seismic database information and excess capacity within existing facilities. The acquisition solidified the Company as the second largest producer of natural gas in Canada and the second largest undeveloped landholder in western Canada.

During 2002, the Company completed 128 transactions in the normal course to acquire additional interests in crude oil and natural gas properties at an aggregate expenditure of $516.3 million. These properties are located in the Company's principal operating regions and are comprised of producing and non-producing leases together with related facilities. In addition, the Company disposed of non-operated properties not located in the Company's core regions for proceeds of $76.1 million.

On September 16, 2002, the Company issued US $350.0 million of 10 year 5.45per cent unsecured notes maturing October 1, 2012 and US $350.0 million of 31 year 6.45per cent unsecured notes maturing June 30, 2033 pursuant to a short form shelf prospectus dated August 16, 2002.

## REGULATORY MATTERS

The Company's business is subject to regulations generally established by government legislation and governmental agencies. The regulations are summarized in the following paragraphs.

### CANADA

The petroleum and natural gas industry in Canada operates under various government legislation and regulations, which govern exploration, development, production, refining, marketing, prevention of waste and other activities.

The Company's Canadian properties are located in Alberta, British Columbia, Saskatchewan, Manitoba and the Northwest Territories. Most of these properties are held under leases/licences obtained from the respective provincial or federal governments, which give the holder the right to explore for and produce crude oil and natural gas. The remainder of the properties is held under freehold (private ownership) lands.



Conventional petroleum and natural gas leases issued by Alberta, Saskatchewan and Manitoba have a primary term from two to five years, and British Columbia leases/licences presently have a term of up to ten years. Those portions of the leases that are producing or are capable of producing at the end of the primary term will "continue" for the productive life of the lease. The exploration licences in the Northwest Territories are administered by the Federal Government and only grant the right to explore. They have initial terms of four to five years. A Commercial Discovery Licence must be obtained in order to produce crude oil and natural gas, which requires the approval of a satisfactory development plan.

An oil sands permit and oil sands primary lease is issued for five and fifteen years respectively. If the minimum level of evaluation of an oil sands permit is attained, a primary oil sands lease will be issued out of the permit. Primary oil sands lease is continued based on the minimum level of evaluation attained on such lease. Continued primary oil sands leases that are designated as "producing" will continue for their productive lives while those designated as "non-producing" can be continued by payment of escalating rentals.

The provincial governments regulate the production of crude oil and natural gas as well as the removal of natural gas and natural gas liquids from each province. Government royalties are payable on crude oil and natural gas production from leases owned by the province. The royalties are determined by regulation and are generally calculated as a percentage of production varied by a number of different factors including selling prices, production levels, recovery methods, transportation and processing costs, location and date of discovery.

The Company is subject to federal and provincial income taxes in Canada at a combined rate of approximately 42 per cent after allowable deductions.

INTERNATIONAL

Under existing law, the UK Government has broad authority to regulate the petroleum industry, including the power to regulate exploration, development, conservation and rates of production.

Production from offshore fields as defined by applicable legislation, whose development was approved prior to April 1, 1982, were subject to Royalty of 12.5 per cent on or after deduction of certain allowances. Fields receiving development approval after April 1, 1982 were not subject to Royalty. On November 27, 2002, the UK Government announced the elimination of Royalty effective January 1, 2003.

Crude oil and natural gas fields granted development approval before March 16, 1993 are subject to UK Petroleum Revenue Tax ("PRT") of 50 per cent charged on crude oil and natural gas profits. Crude oil and natural gas fields granted development approval on or after March 16, 1993 are exempted from PRT. Profits for PRT purposes are calculated on a field-by-field basis by deducting field operating costs and field development costs from production and third party tariff revenue. In addition, certain statutory allowances are available which may reduce the PRT payable.

The Company is subject to UK Corporation Tax ("CT") on its UK profits as adjusted for CT purposes. PRT paid is a deductible for CT purposes. The current CT rate, which became effective April 1, 1999, is 30 per cent.

On April 17, 2002, the UK Government, in its 2002 budget speech by the UK Chancellor of the Exchequer, announced changes to taxation policies on UK North Sea crude oil and natural gas production. A supplementary CT charge of 10 per cent, charged on the same profits as calculated for `normal' CT but excluding any deduction for financing costs, was added to the current 30 per



cent CT charge. Also the deduction for expenditures on capital items was changed from 25 per cent per annum to 100 per cent in the year incurred.

Terms of licences, including royalties and taxes payable on production or profit sharing arrangements, vary by country and in some countries by concession within each country. For instance, production from the Kiame field, on Block 4 in Angola, was subject to a 6 per cent royalty on gross income and 50 per cent Petroleum Income Tax, which equates to 7 per cent calculated on the Company's gross income. Development of the Espoir field on CI-26, Cote d'Ivoire, is under the terms of a production sharing arrangement that provides that tax or royalty payments to the Government are deemed to be met from the Government's share of profit oil (See "Principal Crude Oil and Natural Gas Properties - Offshore West Africa").

Any changes in government policies or operating environment in the countries where the Company conducts business could have a significant impact on the Company's business ventures in such jurisdictions. Risks of foreign operations include, but are not necessarily limited to, changes of laws affecting foreign ownership, government participation, taxation, royalties, duties, rates of exchange, inflation, exchange control, repatriation of earnings and domestic or international unrest. The effect of changes in any of these factors cannot be accurately predicted.

## COMPETITIVE MATTERS

The crude oil and natural gas industry, domestically and in the international arena, is highly competitive by nature. The Company must compete with integrated oil and natural gas companies and independent producers and marketers of crude oil and natural gas products in all aspects of the Company's business. This competition extends to exploration, property and asset acquisition and the selling of the Company's crude oil and natural gas products. The financial strength of some of the Company's competitors may be greater than that of the Company.

## ENVIRONMENTAL MATTERS

The Company carries out its activities in compliance with all relevant regional, national and international regulations and best industry practice. Environmental specialists in the UK and Canada review the operations of the Company's world-wide interests and report on a regular basis to the senior management of the Company, which reports directly to the Board of Directors.

The Company regularly meets with, and submits to inspections by the various governments in the regions where the Company operates. At present, the Company believes that it meets all 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 crude oil and natural gas industry, it is not anticipated that the Company's competitive position within the industry will be adversely affected. The Company has internal procedures designed to ensure that the environmental aspects of new acquisitions and developments are taken into account prior to proceeding. The Company's environmental plan and operating guidelines focus on minimizing the environmental impact of field operations while meeting regulatory requirements and corporate standards. The Company's proactive program includes: an annual environmental compliance audit and inspection program of our operating facilities; an aggressive suspended well inspection program to support future development or eventual abandonment; appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment; an effective surface reclamation program; progressive due diligence related to groundwater monitoring; prevention of



and reclamation of spill sites, greenhouse gas reduction, and, flaring and venting reduction. Since 1995, the Company has reduced its greenhouse gas emissions by more than four million tonnes annually. This represents approximately 40per cent of Canada's oil and natural gas industry reductions based on the Canadian Association of Petroleum Producers data. CNRL participates in Canada's Climate Change Voluntary Challenge & Registry Inc. The Company has been a Gold Level Reporter since 2000. CNRL continues to invest in proven and new technologies and in improved operating strategies that will help us achieve our overall goal of a net reduction of greenhouse gas emissions per unit of production.

The costs incurred by the Company for compliance with environmental matters and site restoration costs amount to less than two per cent of the total exploration and development expenditures incurred by the Company in each of the years ended December 31, 2002, 2001 and 2000.

## DESCRIPTION OF THE BUSINESS

CNRL is a Canadian based senior independent energy company engaged in the acquisition, exploration, development, production, marketing and sale of crude oil, natural gas liquids and natural gas. The Company's principal core regions of operations are western Canada, the United Kingdom sector of the North Sea and offshore West Africa.

The Company focuses on exploiting its core properties and actively maintaining cost controls. Whenever possible CNRL takes on significant ownership levels, operates the properties and attempts to dominate the local land position and operating infrastructure. The Company has grown through a combination of internal growth and strategic acquisitions. Acquisitions are made with a view to either entering new core regions or increasing dominance in existing core regions.

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces: namely natural gas, light oil, Pelican Lake oil, primary heavy oil and thermal heavy oil. The Company's operations are centred on balanced product offerings, which together provide complementary infrastructure and balance throughout the business cycle. Natural gas is the largest single commodity sold, accounting for 49 per cent of 2002 production. Virtually all of the Company's natural gas and natural gas liquids production is located in the Canadian provinces of Alberta and British Columbia and is marketed in Canada and the United States. Light oil, representing 21 per cent of 2002 production, is located principally in the Company's North Sea and offshore West Africa properties, with additional production in the Provinces of Saskatchewan, British Columbia and Alberta. Primary and thermal heavy oil operations in the Provinces of Alberta and Saskatchewan account for 23 per cent of 2002 production. Other heavy oil, which accounts for 7 per cent of 2002 production, is produced from the Pelican Lake area in central Alberta. This production, which has medium oil netback characteristics, is developed through a staged horizontal drilling program. Midstream assets, comprised of three crude oil pipelines and an electricity co-generation facility, provide cost effective infrastructure supporting the heavy and medium oil operations. CNRL expects its ownership of oil sands leases near Ft. McMurray, Alberta to provide a basis for long-term synthetic oil production growth.

As a result of the Company's undeveloped land base of 10.2 million net acres in western Canada, its international concessions and the Alberta oil sands leases, the Company believes it has sufficient project portfolios in each of the product offerings to provide growth for the next several years.



## A. PRINCIPAL CRUDE OIL AND NATURAL GAS PROPERTIES

Set forth below is a summary of the principal crude oil and natural gas properties as at December 31, 2002. The information is proportionate to the working interests and royalty interests owned by the Company.

| | 2002 AVERAGE DAILY PRODUCTION RATES | YEAR ENDED DECEMBER 31, 2002 | WELLS DRILLED IN 2002 | INFR AS AT DE |
|---|---|---|---|---|

| REGION | OIL & NGLs Mbbls | NATURAL GAS MMcf | UNDEVELOPED ACREAGE (thousands) | Oil/Natural Gas/D&A (excludes stratigraphic test & service wells) | Pipeline (thousand miles) | |
|---|---|---|---|---|---|---|
| NORTH AMERICA | | | | | | |
| Northeast B. C. | 7.4 | 450.6 | 1,513 | 2.1 /40.2/ 4.4 | 2.0 | |
| Northwest Alberta | 6.6 | 171.2 | 1,821 | 2.1 / 7.5/ 3.0 | 1.8 | |
| North Alberta | 135.9 | 419.8 | 5,935 | 246.0 /62.4/ 15.0 | 8.2 | |
| Horizon Oil Sands | - | - | 117 | - / -/ - | - | |
| South Alberta | 9.0 | 145.8 | 666 | 1.0 /51.6/ 2.5 | 2.6 | |
| Southeast Saskatchewan | 9.4 | 3.2 | 161 | 4.3 / -/ 1.0 | - | |
| Non - core areas | 1.4 | 13.3 | 1,940 | 0.7 / -/ - | - | |
| INTERNATIONAL | | | | | | |
| North Sea | 38.8 | 27.1 | 410 | 4.9 / -/ - | 0.1 | |
| Offshore West Africa | | | | | | |
| Angola | 0.8 | - | 610 | - / -/ 0.3 | - | |
| Cote d'Ivoire | 6.0 | 1.3 | 333 | 2.4 / -/ 1.2 | - | |
| TOTAL | 215.3 | 1,232.3 | 13,506 | 263.5 /161.7/ 27.4 | 14.7 | 1 |

Set forth below is a summary of the number of gross and net wells within the Company that are producing as of December 31, 2002:

| JURISDICTION | NATURAL GAS WELLS GROSS | NATURAL GAS WELLS NET | OIL WELLS GROSS | OIL WELLS NET | T GROSS |
|---|---|---|---|---|---|
| NORTH AMERICA | | | | | |
| British Columbia | 790 | 685.8 | 276 | 242.1 | 1,066 |
| Alberta | 7,216 | 6,574.4 | 5,883 | 5,555.9 | 13,099 |
| Saskatchewan | 526 | 513.6 | 1,659 | 1,408.1 | 2,185 |
| Manitoba | - | - | 112 | 108.2 | 112 |
| Northwest Territories | 3 | - | - | - | 3 |
| INTERNATIONAL | | | | | |
| North Sea | - | - | 162 | 130.3 | 162 |
| Offshore West Africa | | | | | |
| Angola | - | - | - | - | - |

| | | | | | |
|---|---|---|---|---|---|
| Cote d'Ivoire | - | - | 7 | 4.1 | 7 |
| TOTAL | 8,535 | 7,773.8 | 8,099 | 7,448.7 | 16,634 |

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NORTHEAST BRITISH COLUMBIA

This region comprises lands from south of Fort St. John, British Columbia to the northern border of British Columbia. Similar geological attributes extend throughout the region, producing light oil, natural gas liquids and natural gas. The Company holds working interests ranging up to 100 per cent and averaging 76 per cent in 2,703,335 gross acres (2,053,145 net) 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 natural gas liquids are found in numerous zones at depths reaching approximately 2,000 vertical meters. 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 3,500 meters. The exploration strategy focuses on comprehensive evaluation through two-dimensional seismic, three-dimensional seismic and targeting economic geological areas close to existing infrastructure. Applying under-balanced, multi-leg horizontal drilling has also proven highly effective in this region. Natural gas production from the region averaged 450.6 million cubic feet per day for 2002, an increase of 42 per cent from the average of 317.5 million cubic feet per day produced for 2001. Crude oil and natural gas liquids production decreased to 7.4 thousand barrels per day in 2002 from an average of 9.2 thousand barrels per day in 2001.

This region contains the Ladyfern Slave Point natural gas pool, which is estimated to contain between 660 and 680 billion cubic feet of natural gas-in-place. During 2001, the Company drilled 8 net natural gas wells in the area with a total production capability of over 600 million cubic feet per day. Prior to the first quarter of 2002, production from the area had been restricted due to insufficient processing facilities and pipelines with production exiting 2001 at approximately 150 million cubic feet per day. In the first quarter of 2002, additional facilities were constructed which enabled the Company to increase production to approximately 210 million cubic feet per day in June 2002. Commencing in late August 2002, water encroachment resulted in the start of significant declines from the pool. At the end of 2002, production, net to the Company, was at 100 million cubic feet per day with expectations for 2003 to exit at approximately 25 million cubic feet per day. The Ladyfern field is not representative of typical natural gas pools both due to its overall size and its production profile of very high production volumes with a very rapid decline. Typical natural gas decline rates approximate 23 per cent for other natural gas fields owned by the Company.

Through the acquisition of Ranger in 2000, the Company acquired an interest and operatorship in extensive acreage adjacent to the northern border of this region. A further acquisition in the fourth quarter of 2001 resulted in the Company obtaining 100 per cent ownership in its producing natural gas assets and undeveloped land in the Helmet area of the region. Ranger had drilled a number of producing natural gas wells on the acreage. Further development of this acreage will be enhanced through the facilities and infrastructure owned by the Company in the region. Having identified optimal drilling strategies in the region, Canadian Natural plans a multi-well annual drilling program commencing in 2003.

During 2002 the Company drilled 2.1 (2001- 6.1) net oil wells, 40.1 (2001 - 68.3) net natural gas wells, 1.0 (2001 - 0.0) service wells and 4.4 (2001 - 6.0) net abandoned wells on its lands in this region for a total of 47.6 (2001 - 80.4) net wells. The Company held an average 93 per cent working interest in these wells. The Company owns and operates significant production facilities in this region as noted above. Interests are also owned in additional facilities operated by other industry participants. All of the facilities are in close proximity to sales facilities.



NORTHWEST ALBERTA

The Company holds working interests ranging up to 100 per cent and averaging 82 per cent in 2,733,501 gross (2,252,967 net) acres of producing and undeveloped land in the region.

The majority of the Company's holdings in the region were obtained through the Plan of Arrangement in 2002, which facilitated the acquisition of RAX. This region contains exceptional exploration and exploitation opportunities as well as substantial available capacity within an extensively owned and operated infrastructure. In this region, Canadian Natural produces liquids rich natural gas from multiple, often technically complex horizons, with formation depths ranging from 1,000 to 4,500 metres. The northern portion of this core region provides extensive multi-zone Cretaceous opportunities similar to the geology of the Company's North Alberta core region. The southern portion provides a significant opportunity in the regionally extensive Cretaceous Cardium zone. The Cardium is a complex, tight natural gas reservoir where high productivity can be achieved due to greater matrix porosity or natural fracturing. Canadian Natural has chosen to pursue a modest 2003 development plan in this region so that detailed geological, geophysical and engineering work can be completed and interpreted.

Natural gas production from the region averaged 171.2 million cubic feet per day for 2002, an increase of 237 per cent from the average of 50.8 million cubic feet per day for 2001. Crude oil and natural gas liquids production increased to 6.6 thousand barrels per day in 2002 from 1.4 thousand barrels per day in 2001. During 2002 the Company drilled 2.1 (2001-2.0) net oil wells, 7.5 (2001-5.8) net natural gas wells, and 3.0 (2001-3.5) net abandoned wells on its lands in this region for a total of 12.6 (2001-11.3) net wells. The Company held an average 79 per cent working interest in these wells. The Company owns and operates significant production facilities in this region as noted above, many of which have significant excess capacity, providing for cost effective future expansion of operations. All of the facilities are in close proximity to sales facilities.

NORTH ALBERTA

The Company holds working interests ranging up to 100 per cent and averaging 82 per cent in 9,845,501 gross (8,117,571 net) acres of producing and undeveloped land in the region. The region comprises lands located from townships 33 to 101 and west from Range 17 W 3 meridian in Saskatchewan to Range 10 W 5 meridian in Alberta.

Over most of the region both sweet and sour natural gas reserves are produced from numerous productive horizons at depths up to approximately 1,500 meters. In the southwest portion of the region, natural gas liquids and light oil are also encountered at slightly deeper depths. The region continues to be one of the Company's largest natural gas producing regions, with natural gas production from the region amounting to 419.8 million cubic feet per day in 2002 compared to 357.0 million cubic feet per day in 2001. Crude oil and natural gas liquids production from this region decreased to 135.9 thousand barrels per day in 2002 from 141.2 thousand barrels per day in 2001.

In the area near Lloydminster, Alberta, reserves of heavy oil (averaging 12(Degree) - 14(degree) API) and natural gas are produced through conventional vertical, slant and horizontal well bores from a number of productive horizons up to 1,000 meters deep. The energy required to flow the heavy oil to the wellbore in this type of heavy oil reservoir comes from solution gas. The oil viscosity and the reservoir quality will determine the amount of crude oil produced from the reservoir, which will vary from three to twenty per cent. A key component to maintaining profitability in



the production of heavy oil is to be a low cost producer. The Company continues to achieve low costs by holding a dominant position that includes a significant land base and an extensive infrastructure of batteries and disposal facilities.

The price received for heavy oil is discounted from the benchmark WTI price and during the last quarter of 2000, this differential widened to historically high levels. As a result, the Company took a proactive stance and consciously reduced the number of heavy oil wells drilled in 2001, reduced heavy oil production by 15 thousand barrels per day beginning December 2001 and changed the steaming pattern at its Primrose facility. The heavy oil differential, as expected, narrowed to more historical levels, allowing the Company to bring most of this production back on-line and expand 2002 drilling programs. The Company continues to monitor this market and work on strategies to eliminate some of the uncertainty surrounding this commodity pricing.

Ranger owned significant land and production in this region, with much of its land being contiguous to CNRL holdings. With the operations combined, future development of the total lands in the region became more effective and provides opportunities for cost savings. As part of the acquisition of Ranger, the Company also acquired a 50 per cent interest in the ECHO Pipeline system, a crude oil transportation pipeline; and, in 2001 the Company acquired the remaining 50 per cent. The pipeline was extended to the Beartrap field during 2001, enhancing further development of the Company's extensive holdings in the area. This pipeline is capable of transporting 57 thousand barrels per day of hot unblended crude oil to sales facilities at Hardisty, Alberta. With minor upgrades, its capacity can be expanded to handle up to 72 thousand barrels per day. The ECHO Pipeline system is a high temperature, insulated pipeline that eliminates the requirement for field condensate blending. The pipeline enables the Company to transport its own production volumes at a reduced operating cost as well as earn third party transportation revenue. The ECHO Pipeline system, together with other midstream assets in which the Company has partial interests, permits CNRL to transport in excess of 80 per cent of its heavy oil to the international mainline liquids pipelines. This transportation control enhances the Company's ability to control the full spectrum of costs associated with the development and marketing of its heavy oil.

Production from the Primrose and Wolf Lake fields located near Bonnyville, Alberta involves processes that utilize steam to increase the recovery of the oil. The two processes employed by the Company are cyclic steam stimulation and

SAGD. Both recovery processes inject steam to heat the heavy oil deposits, reducing the oil viscosity and therefore improving its flow characteristics. There is also an infrastructure of gathering systems, a processing plant with a capacity of 60 thousand barrels per day and a 50 per cent interest in a co-generation facility capable of producing 84 megawatts of electricity for the Company's use or sale into the Alberta power grid at pool prices. In 2000, the Company successfully converted and tested two existing pads of wells from low-pressure steaming to high-pressure steaming. This conversion increased average production at the 20 existing wells from 100 to 190 barrels of crude oil per day per well. An additional 24 wells were drilled using the high-pressure steam process with initial production averaging 600 barrels of crude oil per day per well. These results have confirmed the benefits of converting the Primrose field to high-pressure steaming. In 2001, the Company received regulatory approval to convert an additional six low-pressure cyclic pads to high-pressure cyclic pads, and in 2002 received approval to take high-pressure steam methodologies throughout the field. Canadian Natural plans to drill 48 high-pressure wells in 2003, which will increase field production commencing in 2004. Additional development of the leases will be undertaken in phases over the next several years. A successful SAGD heavy oil project in which the Company holds a 50 per cent interest is also in operation in the Saskatchewan portion of this region.



Included in the northern part of this region, approximately 200 miles north of Edmonton, are the Company's 100 per cent-owned holdings at Pelican Lake. These lands contain reserves of 14(Degree)-17(Degree) API heavy oil. Operating costs are low due to no sand production or disposal requirements, the gathering and pipeline facilities in place and negligible water production and disposal. The Company has the major ownership position in the necessary infrastructure including roads, drilling pads, gathering and sales pipelines, batteries, gas plants and compressors to ensure future economic development of the large crude oil pool located on the lands. In the first quarter of 2001, the Company added to its holdings in this area through the acquisition of additional producing lands from another industry participant. Following this acquisition, the Company holds and controls in excess of 80 per cent of the known crude oil pool in this area.

This field contains approximately three billion barrels of original oil-in-place but is only expected to achieve a 6 per cent recovery factor using primary technologies. Hence, in 2002 the Company embarked upon an Enhanced Oil Recovery ("EOR") scheme to increase the ultimate recoveries from the field. The experimental Pelican Lake emulsion flood continues, with injection since early April 2002. Indications to date suggest that the recovery mechanism is very efficient, however response time is slow. Canadian Natural will be working to increase the financial returns on the EOR scheme by finding the optimal balance between response time and recovery factors. To this end, an observation well will be drilled in the first quarter of 2003 to assess the effectiveness of the injection to date. The Company will also be implementing a demonstration scale waterflood project to evaluate this secondary recovery technique, which should increase response time, but at the expense of overall recovery factors. If either project is successful or a combination thereof, the recovery factor from the thin Pelican Lake sands will substantially increase.

During 2002, the Company drilled 62.4 (2001 - 111.2) net natural gas wells, 246.0 (2001 - 210.6) net oil wells, 148.5 (2001 - 79.5) net stratigraphic tests wells, 2.5 services wells (2001 - 15.0) and 15.0 (2001 - 21.8) net wells that were abandoned for a total of 474.4 (2001 - 438.1) net wells. The Company's average working interest in these wells was in excess of 93 per cent. The Company operates and owns significant infrastructure in the region as shown above and has additional interests in plants and compressors in the region, which are operated by other companies.

HORIZON OIL SANDS PROJECT

The Company holds 100 per cent working interest in 116,596 gross acres located in this region comprising the Horizon Oil Sands Project ("the Horizon Project"). During 2001, the Company filed a public disclosure document as the initial step in making application to obtain regulatory approval for a long-term oil sands project that has four components: surface mining and bitumen processing, in-situ operations, an upgrader and associated infrastructure. The first phase of the front-end engineering work on the Horizon Project has been completed. Regulatory submissions, including an environmental Impact Assessment and Project Description were completed and filed in June 2002. Following filing for regulatory approvals, the Company commenced the Design Basis Memorandum, which is the second of the three phases of engineering design work, and is expected to be completed by the beginning of the second quarter of 2003.

Due to the uncertainty of the impact of the Kyoto Protocol on the Horizon Project, the Company delayed the start-up of the Engineering Design Specification ("EDS") phase of engineering and reduced its 2003 capital budget for the Horizon Project from $300 million to $211 million. Canadian Natural believes that certainty of long-term economic consequences of the Kyoto Protocol on the Horizon Project is required prior to the final commitment for an investment as



large as the Horizon Project. Recently the Federal Government has provided some limits to the cost of Kyoto implementation through 2012; however, beyond 2012 no implementation certainty exists. As the Horizon Project is scheduled to commence production in 2008 and produce for over 40 years, the lack of clarity on Kyoto implementation over the long term precludes Canadian Natural's ability to commit to the construction of the Horizon Project at this time. Although a sufficient level of implementation certainty to start construction does not exist today, Canadian Natural anticipates such levels of certainty will be achieved, and therefore has decided to continue with the EDS phase of engineering. The EDS will commence in July of 2003 with related 2003 expenditures included in the Company's current Horizon Project budget of $211 million.

Canadian Natural anticipates receiving regulatory approvals for the Horizon Project from the Energy and Utilities Board in late 2003. The Company would be in a position to commence site clearing and pre-construction in 2004, with full construction commencing upon achieving a targeted 80 per cent completion of detailed engineering and design. The Company expects that the first phase of the Horizon Project would then be commissioned in 2008 at 110 thousand barrels per day of light synthetic crude oil. The Company expects that phase two would be commissioned in 2010, increasing production to 155 thousand barrels per day of production. The Company expects that phase three would be completed in 2012, bringing total production to 232 thousand barrels per day. The Company's leases could support further expansions beyond that date.

No decision has been made on whether to proceed with the construction of the Horizon Project in 2004. If a decision is made to commence construction, the Company will then evaluate and choose between two potential approaches: (i) completion of the Horizon Project in Ft. McMurray, with the $3 billion upgrader on-site; or (ii) completion of the Horizon Project in Ft. McMurray, with secondary upgrading facilities relocated to the U.S. By relocating these facilities to the U.S., a degree of certainty on costs of Kyoto implementation for the Horizon Project could be obtained.

Total expected capital costs of the Horizon Project are $8.0 billion to $8.4 billion, with approximately $4.5 billion to $5.0 billion required to bring the first phase on line and are consistent with the final cost estimates for other recent oil sands mining projects.

The project will provide for a potential recovery of 6 billion barrels of bitumen over an estimated 40-year life span. No reserves from these leases are included in the Company's current reserves of crude oil and natural gas liquids.

During 2002, the Company drilled 293 (2001 - 257) stratigraphic test wells to further delineate the ore body and confirm resource quality and quantity.

SOUTH ALBERTA

The Company holds interests ranging up to 100 per cent and averaging 81 per cent in 1,573,216 gross (1,279,609 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 2,300 meters. Unlike the Company's other three natural gas producing regions, which have areas with limited or winter access only, drilling can take place in this region year round. With a higher sales price for natural gas, it is economic to

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drill shallow wells in closer proximity to each other, which may have smaller overall reserves and lower productivity per well but will achieve a high return on capital employed.

The Company's share of production averaged 9.0 (2001 - 6.7) thousand barrels of crude oil and natural gas liquids per day and 145.8 (2001- 162.3) million cubic feet of natural gas per day in 2002.

During 2002, the Company drilled a total of 1.0 (2001 - 5.0) net oil wells, 51.6 (2001 - 289.9) net natural gas wells and 2.5 (2001 - 0.0) net abandoned wells in this region for a total of 55.1 (2001 - 294.9) net wells. The Company's average working interest in these wells is 92 per cent. The wells are predominantly in areas where the Company already has gathering and processing facilities as noted above.

SOUTHEAST SASKATCHEWAN

The Williston Basin is located in Southeastern Saskatchewan with lands extending into Manitoba and North Dakota. This region was owned by Sceptre and became a core region of the Company in mid 1996 with the acquisition of Sceptre. The Company holds interests ranging up to 100 per cent and averaging 80 per cent in 281,889 gross (226,247 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 2,700 meters. During 2002, net production to the Company averaged 9.4 thousand barrels of crude oil per day compared to an average of 6.5 thousand barrels of crude oil per day in 2001.

The Company drilled 4.3 (2001 - 4.0) net oil wells and 1.0 (2001 - 0.0) net abandoned wells in this region in 2002 for a total of 5.3 (2001 - 4.0) net wells. The Company's average working interest in these wells is 53 per cent. These wells included a number of horizontal wells that further developed the existing known pools of crude oil in the Company's lands.

NORTH SEA

The Company's wholly owned subsidiary CNR International (U.K.) Limited, formerly Ranger Oil (U.K.) Limited, has operated in the North Sea for 30 years and has developed a significant database, extensive operating experience and an experienced staff. The Company owns interests ranging from 7 per cent up to 100 per cent in 839,138 gross (465,619 net) acres of producing and non-producing acreage in the UK sector of the North Sea. In 2002, the Company produced from 12 crude oil fields. The most northerly fields are centered around the Ninian field where the Company has a 73.2 per cent working interest. The central processing facility is connected to other fields including the Columba fields where the Company operates with working interests of 85.8 per cent to 90.7 per cent. In 2002, the Company completed property acquisitions in the northern North Sea that increased ownership levels in the Ninian, Murchison, Lyell and Columba Terraces fields. The Company is now the operator on each of these fields. As part of the transaction the Company also acquired an interest in the Strathspey field and 12 licenses covering 20 exploration blocks and part blocks surrounding the Ninian and Murchison platforms. Increased ownership in the Brent and Ninian pipelines and the Sullom voe Terminal was also acquired. Ownership and operatorship levels in the North Sea are now similar to those levels found throughout the Company's other worldwide operations. The Company also receives tariff revenue from other operators for the transportation and processing of crude oil and natural gas



through the processing facilities. Opportunities for further long reach well development on adjacent fields are provided from the existing processing facilities.

In the central portion of the North Sea, the Company owns a 55.9 per cent working interest in the Banff field and a 45.7 per cent operated working interest in the Kyle field. Production at the Banff field was temporarily curtailed in September 2000 while the owners of the FPSO removed the vessel from the field to make repairs and modifications. Production resumed from the field in 2001. At the Kyle field the Company drilled one additional well and during the summer of 2000 produced this well on an extended well test to confirm reservoir quality. A third well was drilled, tested and connected to production facilities in 2001, with a fourth well drilled and tied in during 2002. The wells at Kyle are tied into a Company operated FPSO, which the Company took over operatorship of in 2001, located at the Curlew field.

For 2003, the Company budgeted to spend a total of $281.0 million on its international holdings in the U. K. sector of the North Sea. These funds will be directed towards drilling an additional 17 wells in the northern North Sea and one additional well in the central North Sea. Other exploitation and waterflood optimization programs will also be carried out in both areas to increase the productivity and recovery factors in these known pools of light oil.

During 2002, production to the Company from this region averaged 38.8 (2001 - 36.3) thousand barrels of crude oil per day and 27.1 (2001 - 12.0) million cubic feet of natural gas per day. The Company drilled 4.9 (2001 - 2.2) net oil wells, 1.2 (2001 - 0.6) net service wells and 0.0 (2001 - 0.2) net abandoned wells in 2002 in this region for a total of 6.1 (2001 - 3.0) net wells. The Company's average working interest in these wells is 41 per cent.

OFFSHORE WEST AFRICA

With the purchase of Ranger in 2000, the Company acquired interests in areas of crude oil and natural gas exploration and development offshore Cote d'Ivoire and Angola, West Africa. The Company owns working interests ranging from 25 per cent to 100 per cent in 2,885,571 gross (1,253,513 net) acres in this region.

COTE D'IVOIRE

The Company owns interests in five exploration licences offshore Cote d'Ivoire comprising 798,403 net acres. During 2001, the Company increased its interest in Block CI-26, which contains the Espoir crude oil and natural gas field, to a 59 per cent operating interest. The Espoir field is located in water depths ranging from 100 to 700 meters. During the 1980s, the Espoir field produced 31 million barrels of crude oil by natural depletion prior to relinquishment by the previous licencees in 1988. The government of Cote d'Ivoire approved a development plan to recover the remaining reserves and the Company will continue its exploitation and development of the field. The development of East Espoir, which includes the drilling of both producing and water injection wells from a single wellhead tower, is continuing and development of the West Espoir field will proceed after full development of East Espoir. Using an FPSO with a capacity of 40 thousand barrels of crude oil per day, crude oil production commenced in the first quarter of 2002 at an initial rate of 8.5 thousand barrels of crude oil per day from one producing well. A subsea pipeline has been constructed for the delivery of associated natural gas to onshore Cote d'Ivoire where it will be sold to local power producers. Production continued at the end of 2002 from three producing wells and two water injection wells. Unanticipated uphole faults encountered in the drilling of a well, which was spud August 2002 has resulted in drilling program delays. The offshore development will continue with two water injection wells and one producing well scheduled for drilling at East Espoir during the first half of 2003. These injectors will enhance the build up of pressures in the upper zones of the oil reservoir, which is scheduled



for perforation by mid-2003, providing up to 5 thousand barrels per day of additional net production. During December 2002 a satellite pool, Emien, was drilled, but encountered no hydrocarbons. The Company anticipates drilling a second, larger satellite pool, Acajou, during the first half of 2003.

In the first quarter of 2001, the Company drilled and tested the Baobab exploration prospect, identified on Block CI-40, in which the Company has a 61 per cent interest, eight kilometres south of the Espoir facilities. The well encountered hydrocarbons at a rate of 6.7 thousand barrels of crude oil per day. A second test well in 2002 also produced hydrocarbons at a rate in excess of 10 thousand barrels of crude oil per day, leading the Company to declare the prospect commercial. The development continues for first oil planned at initial production rates of 45 thousand barrels per day in 2005, increasing with full development to 60 thousand barrels per day. Several components of the subsea infrastructure and the floating production storage and offtake vessel are currently out to bid. This field contains approximately 200 million barrels of recoverable reserves and is operated and 61per cent owned by Canadian Natural.

Field development plans were approved by the Government in December 2002. Seismic surveys have been acquired on the other Cote d'Ivoire blocks and leads or prospects identified.

Political unrest in Cote d'Ivoire has had no impact on the Company's operations. The Company has developed contingency plans to continue Cote d'Ivoire operations from another nearby country if the situation warrants such a move.

The Company's 2003 expenditure budget forecasts expenditures totaling $280 million in offshore West Africa. Expenditures in Cote d'Ivoire of approximately $220 million will result in finalization of drilling and completion operations at Espoir, an exploration well at Acajou and finalization of development plans at Baobab.

During 2002, the Company drilled 2.4 (2001 - 1.2) net oil wells, 0.6 (2001 - 0.6) net service wells and 1.2 (2001 - 0.0) net abandoned wells for a total of 4.2 (2001 - 1.8) net wells. The Company's average working interest in these wells is 61 per cent.

ANGOLA

During 2002, Canadian Natural was awarded operatorship and a 50 per cent working interest in exploration Block 16 situated offshore The People's Republic of Angola. Canadian Natural obtained 3-D seismic over the entire Block 16 before obtaining title and has already identified two targets, Omba in the north and Zenza in the west central portion of the Block. The Company has a two well commitment over a four year time frame expiring August 31, 2006 and currently expects to drill the first of the prospects, Zenza, during the fourth quarter of 2003.

The Company also owned 100 per cent of and operated the offshore Kiame field. The field produced from June 1998 to April 2002 through a leased FPSO. The field reached its economic limit of production and production ceased in April 2002. The Company also had a 25 per cent non-operating interest in Block 19, a 1.2 million-acre block, which lies in water depths of 300 to 1,800 meters. A 2,500 square kilometre 3-D seismic survey was completed in 1999. After interpretation of the seismic and drilling of a 25 per cent interest well in 2002 on Block 19, the Company determined the block was not economic to develop and relinquished its license on the block.



B. CRUDE OIL AND NATURAL GAS RESERVES

The Company retains independent petroleum engineering consultants Sproule Associates Limited ("Sproule") to evaluate the Company's proved and probable crude oil and natural gas reserves and prepare an evaluation report on the Company's total reserves ("Evaluation Report"). For the year ended December 31, 2002, the Evaluation Report includes 89 per cent of the Company's reserves evaluated by Sproule and the remaining 11 per cent internally evaluated by the Company. The Company has retained Sproule since 1989 to evaluate its assets.

The Board of Directors' Reserves Committee meets with Sproule on a regular basis and at such times 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 December 31, 2002.

THE ESTIMATED FUTURE NET REVENUES CONTAINED IN THE FOLLOWING TABLES ARE NOT TO BE CONSTRUED AS A REPRESENTATION OF THE FAIR MARKET VALUE OF THE PROPERTIES TO WHICH THEY RELATE. THE PRESENT WORTH OF ALL PROBABLE RESERVES HAS BEEN REDUCED BY 50 PER CENT TO ACCOUNT FOR RISK. THE ESTIMATED FUTURE NET REVENUES DERIVED FROM THE ASSETS 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 ABANDONMENT LIABILITIES. NO INDIRECT COSTS SUCH AS OVERHEAD, INTEREST AND ADMINISTRATIVE EXPENSES HAVE BEEN DEDUCTED FROM THE ESTIMATED FUTURE NET REVENUES. OTHER ASSUMPTIONS AND QUALIFICATIONS RELATING TO COSTS, PRICES FOR FUTURE PRODUCTION AND OTHER MATTERS ARE SUMMARIZED IN THE NOTES TO THE FOLLOWING TABLES. THERE IS NO ASSURANCE THAT THE PRICE AND COST ASSUMPTIONS CONTAINED IN EITHER THE CONSTANT OR ESCALATED CASES WILL BE ATTAINED AND VARIANCES COULD BE SUBSTANTIAL.

CRUDE OIL, NGL AND NATURAL GAS RESERVES

| | ESCALATED PRICES AND COSTS | | | | |
|---|---|---|---|---|---|
| | GROSS CRUDE OIL & NGL RESERVE VOLUMES (MMbbls) | | | GROSS NATURAL GAS R VOLUMES (B | |
| By Jurisdiction | PROVED RESERVES | PROBABLE RESERVES | TOTAL RESERVES | PROVED RESERVES | PROBAB RESERV |
| NORTH AMERICA | | | | | |
| Canada | 665 | 77 | 742 | 3,046 | 4 |
| United States | - | - | - | 2 | |
| INTERNATIONAL | | | | | |
| United Kingdom | 200 | 73 | 273 | 71 | |
| Cote d'Ivoire | 96 | 70 | 166 | 90 | |
| Angola | - | - | - | - | |
| TOTAL | 961 | 220 | 1,181 | 3,209 | 4 |

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CRUDE OIL, NGL AND NATURAL GAS RESERVES

ESCALATED PRICES AND COSTS

CRUDE OIL AND NATURAL

| | GAS LIQUIDS (MMbbls) | | NATURAL |
|---|---|---|---|
| | GROSS | NET | GROSS |
| Proved developed producing | 459 | 412 | 2,607 |
| Proved developed non-producing | 74 | 66 | 203 |
| Proved undeveloped | 428 | 389 | 399 |
| Total proved reserves | 961 | 867 | 3,209 |
| Probable reserves | 220 | 194 | 451 |
| Total proved and probable reserves | 1,181 | 1,061 | 3,660 |

ESTIMATED FUTURE NET REVENUES

| ($ Millions) | ESCALATED PRICES AND COSTS | | |
|---|---|---|---|
| | UNDISCOUNTED | DISCOUNTED AT | |
| | | 10% | 15% |
| Proved developed producing | $15,776 | $9,880 | $8,535 |
| Proved developed non-producing | 1,711 | 1,087 | 927 |
| Proved undeveloped | 4,452 | 1,811 | 1,265 |
| Total proved reserves | 21,939 | 12,778 | 10,727 |
| Probable reserves | 2,193 | 1,038 | 780 |
| Total proved and probable reserves | $24,132 | $13,816 | $11,507 |

CRUDE OIL, NGL AND NATURAL GAS RESERVES

| | CONSTANT PRICES AND COSTS | | |
|---|---|---|---|
| | CRUDE OIL AND NATURAL GAS LIQUIDS (MMbbls) | | NATURAL |
| | GROSS | NET | GROSS |
| Proved developed producing | 459 | 407 | 2,608 |
| Proved developed non-producing | 76 | 67 | 202 |

| | | | |
|---|---|---|---|
| Proved undeveloped | 427 | 374 | 399 |
| Total proved reserves | 962 | 848 | 3,209 |
| Probable reserves | 219 | 186 | 450 |
| Total proved and probable reserves | 1,181 | 1,034 | 3,659 |

ESTIMATED FUTURE NET REVENUES

| ($Millions) | CONSTANT PRICES AND COSTS | | |
|---|---|---|---|
| | UNDISCOUNTED | DISCOUNTED A | |
| | | 10% | 15% |
| Proved developed producing | $21,752 | $13,881 | $11,946 |
| Proved developed non-producing | 2,509 | 1,604 | 1,360 |
| Proved undeveloped | 8,297 | 3,850 | 2,871 |
| Total proved reserves | 32,558 | 19,335 | 16,177 |
| Probable reserves | 3,267 | 1,630 | 1,249 |
| Total proved and probable reserves | $35,825 | $20,965 | $17,426 |



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 mean the Company's gross reserves less all royalties payable to others.

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

4. "Proved developed non-producing" reserves are those proved 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 proved reserves are expected to be produced through the existing wells in the predictable future and are classified as proved

developed since the cost of making such reserves available for production is relatively small, compared to the cost of a new well.

5. "Proved undeveloped" reserves are those proved 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. "Proved" reserves are those quantities of crude oil, natural gas and natural gas liquids, 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 crude oil and natural 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 proved 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 proved reserves. THE ESTIMATED FUTURE NET REVENUES OF THE PROBABLE RESERVES SET FORTH ABOVE HAVE BEEN RISK WEIGHTED BY 50 PER CENT TO ACCOUNT FOR THE PROBABILITY OF OBTAINING PRODUCTION FROM SUCH RESERVES.

8. Canadian securities legislation and policies permit the disclosure, which is included or incorporated by reference herein under a multi-jurisdicitional disclosure system adopted by the SEC, of probable reserves which may not be disclosed in registration statements otherwise filed with the SEC. Probable reserves are generally believed to be less likely to be recovered than proved reserves. The reserve estimates, included or incorporated by reference in this Annual Information Form could be materially different from the quantities and values ultimately realized.

9. All values are shown in Canadian dollars.

10. The escalated price and cost cases assume 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 2014, reference prices and costs are escalated at 1.5 per cent per year. Future crude oil, natural gas liquids and natural gas price forecasts were based on Sproule's January 1, 2003 crude oil, natural gas liquids and natural gas pricing model.

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

| | NATURAL GAS | CRUDE OIL & |
|---|---|---|
| | | WTI @ |

| YEAR | COMPANY AVERAGE PRICE $CDN/MCF | HENRY HUB LOUISIANA $US/MMBTU | AECO $CDN/MMBTU | BRITISH COLUMBIA PLANTGATE $CDN/MMBTU | AVERAGE PRICE $CDN/BBL | COMPANY CUSHING (i) $US/BBL | HARDIS HEAV 12(DEGREE $CDN/B |
|---|---|---|---|---|---|---|---|
| 2003 | 5.73 | 4.39 | 5.89 | 5.94 | 30.59 | 25.99 | 25.92 |
| 2004 | 5.22 | 4.05 | 5.38 | 5.43 | 27.91 | 23.60 | 23.78 |
| 2005 | 4.62 | 3.61 | 4.77 | 4.82 | 25.18 | 21.63 | 21.16 |
| 2006 | 4.31 | 3.40 | 4.45 | 4.48 | 25.48 | 21.96 | 21.83 |
| 2007 | 4.46 | 3.45 | 4.61 | 4.66 | 26.22 | 22.29 | 22.89 |
| 2008 | 4.52 | 3.50 | 4.67 | 4.74 | 26.55 | 22.62 | 23.38 |
| 2009 | 4.67 | 3.56 | 4.86 | 4.93 | 27.25 | 22.96 | 24.47 |
| 2010 | 4.77 | 3.61 | 4.94 | 5.01 | 27.53 | 23.31 | 24.98 |
| 2011 | 4.87 | 3.66 | 5.03 | 5.10 | 27.75 | 23.66 | 25.50 |
| 2012 | 4.96 | 3.72 | 5.13 | 5.20 | 27.89 | 24.01 | 26.03 |
| 2013 | 5.06 | 3.77 | 5.22 | 5.29 | 28.45 | 24.37 | 26.57 |
| 2014 | 5.16 | 3.83 | 5.31 | 5.38 | 29.18 | 24.74 | 27.11 |

(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 (degree)API), low sulphur content crude oil at Edmonton, Alberta.

11. Product prices in the constant price evaluation are those in effect at the end of the year adjusted for the average light oil to heavy oil differential used for 2003 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 Evaluation Report. Product prices have not been escalated beyond 2003. In addition, operating and capital costs have not been increased on an inflationary basis.

12. Estimated future net revenue from all assets is income derived from the sale of net reserves of crude oil, natural gas and natural gas liquids, less all capital costs, production taxes, and operating costs and before provision for income taxes, administrative overhead costs and abandonment liabilities.

13. The estimated total capital costs net to the Company necessary to achieve the estimated future net proved and risked weighted probable production revenues are:

| | ESCALATED PRICE CASE ($Millions) | CONSTANT PRICE CASE ($Millions) |
|---|---|---|
| 2003 | 648 | 641 |
| 2004 | 965 | 930 |
| 2005 | 359 | 337 |
| 2006 | 291 | 268 |
| 2007 | 150 | 136 |
| 2008 | 218 | 198 |
| 2009 | 130 | 115 |
| 2010 | 58 | 49 |

| | | |
|---|---|---|
| 2011 | 180 | 157 |
| 2012 | 50 | 41 |
| Thereafter | 288 | 237 |
| | 3,337 | 3,109 |

14. Estimated future net revenue includes the ARTC which, in both the escalated and constant price case, is estimated to be $24.0 million undiscounted and $5.2 million, $3.6 million and $2.7 million discounted at 10%, 15% and 20% respectively.

15. Estimated future net revenue includes the value of the Company's Corporate Capital GCA - Alberta Crown Credits which, in both the escalated and constant price case is estimated to be $204.1 million undiscounted and $158.7 million, $143.1 million and $130.5 million discounted at 10%, 15% and 20% respectively.

16. Estimated future net revenue includes the value of the Company's midstream assets which is estimated to be $573.4 million undiscounted and $286.7 million, $225.1 million and $184.9 million in the escalated price case discounted at 10%, 15% and 20% respectively. In the constant price case the value of the Company's midstream assets is estimated to be $621.4 million undiscounted and $300.1 million, $233.4 million and $190.5 million discounted at 10%, 15% and 20% respectively.

17. The Evaluation 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.

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C. RECONCILIATION OF CHANGES IN RESERVES

The following table summarizes the changes in reserves before deduction of royalties payable to others during the past year:

| | CRUDE OIL AND NATURAL GAS LIQUIDS (MMbbls) | | | | NATU | |
|---|---|---|---|---|---|---|
| | NORTH AMERICA | NORTH SEA | OFFSHORE WEST AFRICA | TOTAL | NORTH AMERICA | NORT SEA |
| PROVED RESERVES | | | | | | |
| Reserves, December 31, 2001 | 644 | 85 | 61 | 790 | 2,566 | |
| Extensions and discoveries | 31 | 1 | 18 | 50 | 132 | |
| Property purchases | 51 | 112 | 0 | 163 | 872 | |
| Property disposals | (1) | (18) | 0 | (19) | (4) | ( |
| Production | (62) | (14) | (3) | (79) | (439) | ( |
| Revisions of prior estimates | 2 | 34 | 20 | 56 | (79) | |
| Reserves, December 31, 2002 | 665 | 200 | 96 | 961 | 3,048 | |

| | | | | | |
|---|---|---|---|---|---|
| PROBABLE RESERVES | | | | | |
| Reserves, December 31, 2001 | 95 | 23 | 51 | 169 | 349 |
| Extensions and discoveries | 0 | (1) | (14) | (15) | 8 |
| Property purchases | 10 | 24 | 0 | 34 | 82 |
| Property disposals | 0 | (4) | 0 | (4) | 0 |
| Revisions of prior estimates | (28) | 31 | 33 | 36 | (37) |
| Reserves, December 31, 2002 | 77 | 73 | 70 | 220 | 402 |
| Total Reserves, December 31, 2002 | 742 | 273 | 166 | 1,181 | 3,450 |



D. CRUDE OIL AND NATURAL GAS PRODUCTION

The Company's working interest share of oil, NGLs and natural gas production and revenues received for the last two financial years is summarized in the following tables:

| | YEAR ENDED DECEMBER 31 | | | |
|---|---|---|---|---|
| | 2002 | 2001 | 2000 | 1999 |
| Daily Production | | | | |
| Crude Oil and NGLs (bbls/d) | 215,335 | 206,323 | 173,591 | 86,750 |
| Natural Gas (MMcf/d) | 1,232.3 | 918.1 | 794.4 | 721.0 |
| Annual Production | | | | |
| Crude Oil and NGLs (Mbbls) | 78,597 | 75,308 | 63,534 | 31,664 |
| Natural Gas (Bcf) | 449.8 | 335.1 | 290.8 | 263.2 |

NETBACKS
INFORMATION BY QUARTER

| | YEAR 2002 | | | | | YEAR 2 | | |
|---|---|---|---|---|---|---|---|---|
| | 1ST QUARTER | 2ND QUARTER | 3RD QUARTER | 4TH QUARTER | YEAR ENDED | 1ST QUARTER | 2ND QUARTER | 3RD QUARTER |
| AVERAGE DAILY PRODUCTION | | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| VOLUMES | | | | | | | | |
| Crude Oil and NGLs (bbls) | 188,439 | 189,386 | 242,051 | 240,596 | 215,335 | 205,588 | 214,716 | 207,065 |
| Natural Gas (Mcf) | 1,053.3 | 1,077.8 | 1,427.4 | 1,365.2 | 1,232.3 | 850.8 | 884.6 | 923.8 |
| PRODUCT NETBACKS | | | | | | | | |
| Crude oil and NGLs ($/bbl) | | | | | | | | |
| Sales Price | $ 24.50 | $ 28.27 | $ 33.57 | $ 31.10 | $ 29.76 | $22.060 | $ 25.32 | $ 28.37 |
| Royalties | 2.28 | 3.02 | 3.56 | 3.53 | 3.16 | 2.36 | 2.42 | 2.47 |
| Production Expenses | 7.81 | 7.95 | 8.67 | 9.10 | 8.45 | 8.18 | 7.57 | 7.29 |
| NETBACK | $ 14.41 | $ 17.30 | $ 21.34 | $ 18.47 | $ 18.15 | $ 11.52 | $ 15.33 | $ 18.61 |
| Natural Gas ($/Mcf) | | | | | | | | |
| Sales Price | $ 3.06 | $ 3.68 | $ 3.13 | $ 5.00 | $ 3.76 | $ 9.306 | $ 5.93 | $ 3.12 |
| Royalties | 0.55 | 0.77 | 0.67 | 1.09 | 0.78 | 2.40 | 1.47 | 0.67 |
| Production Expenses | 0.58 | 0.57 | 0.55 | 0.57 | 0.57 | 0.50 | 0.50 | 0.50 |
| NETBACK | $ 1.93 | $ 2.34 | $ 1.91 | $ 3.34 | $ 2.41 | $ 6.40 | $ 3.96 | $ 1.95 |
| CRUDE OIL AND NGL NETBACKS BY TYPE | | | | | | | | |
| Light/Pelican Lake/NGLs ($/bbl) | | | | | | | | |
| Sales Price | $ 28.58 | $ 31.84 | $ 36.58 | $ 36.38 | $ 33.84 | $330.96 | $ 33.59 | $ 32.75 |
| Royalties | 3.25 | 4.04 | 4.48 | 4.39 | 4.10 | 4.03 | 3.86 | 3.30 |
| Production Expenses | 7.48 | 8.36 | 10.06 | 9.38 | 8.97 | 5.99 | 6.10 | 6.12 |
| NETBACK | $ 17.85 | $ 19.44 | $ 22.04 | $ 22.61 | $ 20.77 | $ 20.94 | $ 23.63 | $ 23.33 |
| Heavy ($/bbl) | | | | | | | | |
| Sales Price | $ 20.10 | $ 24.20 | $ 29.78 | $ 24.54 | $ 24.89 | $212.76 | $ 15.83 | $ 23.21 |
| Royalties | 1.21 | 1.86 | 2.42 | 2.45 | 2.03 | 0.61 | 0.77 | 1.50 |
| Production Expenses | 8.18 | 7.48 | 6.91 | 8.77 | 7.84 | 10.48 | 9.24 | 8.68 |
| Netback | $ 10.62 | $ 14.86 | $ 20.45 | $ 13.32 | $ 15.02 | $ 1.67 | $ 5.82 | $ 13.03 |

NOTE: Pelican Lake oil has an API of 14(0)to 17(0), but receives medium quality crude netbacks due to exceptionally low operating costs and low royalty rateS.



NETBACKS
INFORMATION BY QUARTER

| | YEAR 2002 | | | | | YEAR 2 | | |
|---|---|---|---|---|---|---|---|---|
| | 1ST QUARTER | 2ND QUARTER | 3RD QUARTER | 4TH QUARTER | YEAR ENDED | 1ST QUARTER | 2ND QUARTER | 3RD QUARTER |
| SEGMENTED NORTH AMERICA PRODUCT NETBACKS | | | | | | | | |
| Light/Pelican Lake/NGLs ($/bbl) | | | | | | | | |
| Sales Price | $ 25.27 | $ 28.90 | $ 32.83 | $ 31.94 | $ 30.01 | $ 27.04 | $ 27.49 | $ 29.95 |
| Royalties | 4.24 | 5.11 | 5.98 | 5.81 | 5.35 | 4.57 | 5.04 | 4.17 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Production Expenses | 5.25 | 5.30 | 5.00 | 5.28 | 5.20 | 3.84 | 4.02 | 4.22 |
| NETBACK | $ 15.78 | $ 18.49 | $ 21.85 | $ 20.85 | $ 19.46 | $ 18.63 | $ 18.43 | $ 21.56 |
| | | | | | | | | |
| Heavy ($/bbl) | | | | | | | | |
| Sales Price | $ 20.01 | $ 24.20 | $ 29.78 | $ 24.54 | $ 24.89 | $ 12.76 | $ 15.83 | $ 23.21 |
| Royalties | 1.21 | 1.86 | 2.42 | 2.45 | 2.03 | 0.61 | 0.77 | 1.50 |
| Production Expenses | 8.18 | 7.48 | 6.91 | 8.77 | 7.84 | 10.48 | 9.24 | 8.68 |
| NETBACK | $ 10.62 | $ 14.86 | $ 20.45 | $ 13.32 | $ 15.02 | $ 1.67 | $ 5.82 | $ 13.03 |
| | | | | | | | | |
| Natural Gas ($/Mcf) | | | | | | | | |
| Sales Price | $ 3.05 | $ 3.72 | $ 3.15 | $ 5.04 | $ 3.78 | $ 9.30 | $ 5.99 | $ 3.13 |
| Royalties | 0.57 | 0.79 | 0.69 | 1.11 | 0.80 | 2.40 | 1.49 | 0.68 |
| Production Expenses | 0.56 | 0.55 | 0.52 | 0.55 | 0.55 | 0.50 | 0.50 | 0.50 |
| NETBACK | $ 1.92 | $ 2.38 | $ 1.94 | $ 3.38 | $ 2.43 | $ 6.40 | $ 4.00 | $ 1.95 |
| | | | | | | | | |
| NORTH SEA PRODUCT NETBACKS | | | | | | | | |
| Light Oil ($/bbl) | | | | | | | | |
| Sales Price | $ 33.75 | $ 39.36 | $ 41.68 | $ 41.83 | $ 39.79 | $ 41.04 | $ 43.07 | $ 37.28 |
| Royalties | 1.54 | 1.76 | 2.56 | 2.79 | 2.30 | 2.86 | 2.23 | 1.97 |
| Production Expenses | 10.09 | 15.72 | 18.30 | 14.68 | 15.06 | 9.22 | 8.42 | 8.09 |
| NETBACK | $ 22.12 | $ 21.88 | $ 20.82 | $ 24.36 | $ 22.43 | $ 28.96 | $ 32.42 | $ 27.22 |
| | | | | | | | | |
| Natural Gas ($/Mcf) | | | | | | | | |
| Sales Price | $ 3.77 | $ 1.80 | $ 1.98 | $ 3.20 | $ 2.75 | $ - | $ 1.74 | $ 2.51 |
| Royalties | - | - | - | - | - | - | - | - |
| Production Expenses | 1.33 | 1.90 | 1.78 | 1.25 | 1.53 | - | 0.61 | 0.74 |
| NETBACK | $ 2.44 | $ (0.10) | $ 0.20 | $ 1.95 | $ 1.22 | $ - | $ 1.13 | $ 1.77 |
| | | | | | | | | |
| OFFSHORE WEST AFRICA PRODUCT NETBACKS | | | | | | | | |
| Light Oil ($/bbl) | | | | | | | | |
| Sales Price | $ 37.61 | $ 33.92 | $ 42.78 | $ 43.15 | $ 40.10 | $ 40.58 | $ 39.75 | $ 34.66 |
| Royalties | 1.65 | 1.11 | 1.34 | 1.35 | 1.35 | - | 0.65 | 2.03 |
| Production Expenses | 18.62 | 12.76 | 11.23 | 13.68 | 13.63 | 38.80 | 17.23 | 19.05 |
| NETBACK | $ 17.34 | $ 20.05 | $ 30.21 | $ 28.12 | $ 25.12 | $ 1.78 | $ 21.87 | $ 13.58 |
| | | | | | | | | |
| Natural Gas ($/Mcf) | | | | | | | | |
| Sales Price | | | $ 4.97 | $ 4.63 | $ 4.82 | | | |
| Royalties | | | $ 0.15 | $ 0.15 | $ 0.15 | | | |
| Production Expenses | | | $ 1.77 | $ 1.85 | $ 1.81 | | | |
| NETBACK | $ - | $ - | $ 3.05 | $ 2.63 | $ 2.86 | $ - | $ - | $ - |

NOTE: Pelican Lake oil has an API of 14(0)to 17(0), but receives medium quality crude netbacks due to exceptionally low operating costs and low royalty rates.



E. DRILLING ACTIVITY

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

| | YEAR ENDED DECEMBER 31 | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2002 | | 2001 | | 2000 | | 1999 | |
| | GROSS | NET | GROSS | NET | GROSS | NET | GROSS | NET |
| Natural Gas | 183 | 162 | 576 | 476 | 474 | 408 | 481 | 458 |
| Crude Oil | 316 | 264 | 270 | 231 | 375 | 333 | 229 | 211 |
| Service/Stratigraphic | 456 | 447 | 356 | 353 | 42 | 38 | 11 | 9 |
| Dry & Abandoned | 32 | 27 | 36 | 32 | 46 | 34 | 54 | 49 |
| Total | 987 | 900 | 1,238 | 1,092 | 937 | 813 | 775 | 727 |
| *Total Success Rate | | 94% | | 96% | | 96% | | 93% |

*excluding service and stratigraphic test wells

F. CAPITAL EXPENDITURES

Costs incurred by the Company in respect of its programs of acquisition and disposition, and exploration and development of crude oil and natural gas properties, are summarized in the following tables:

| | YEAR ENDED DECEMBER 31 | | | |
|---|---|---|---|---|
| | 2002 | 2001 | 2000 | 199 |
| | | ($ Millions) | | |
| Corporate acquisition | 2,393.2 | - | 1,687.3 | |
| Net property acquisitions | 440.2 | 519.2 | 150.2 | 1,422. |
| Land acquisition and retention | 113.5 | 100.5 | 79.7 | 46. |
| Seismic evaluation | 63.4 | 94.6 | 40.5 | 17. |
| Well drilling, completion and equipping | 625.6 | 635.3 | 508.9 | 267. |
| Pipeline and production facilities | 292.2 | 395.0 | 335.7 | 143. |
| Reserve replacement expenditures | 3,928.1 | 1,744.6 | 2,802.3 | 1,897. |
| Projects under construction | - | - | - | (6.5 |
| Midstream operations | 20.4 | 97.3 | - | |
| Horizon Project | 68.1 | 26.8 | - | |
| Abandonments | 42.9 | 9.4 | 15.1 | 7. |

| | | | | |
|---|---|---|---|---|
| Head office equipment | 9.9 | 6.4 | 5.9 | 2. |
| Total Net Capital Expenditures | 4,069.4 | 1,884.5 | 2,823.3 | 1,900. |

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| CAPITAL EXPENDITURES BY QUARTER | 2002 THREE MONTHS ENDED ($ Millions) | | |
|---|---|---|---|
| | MAR. 31 | JUNE 30 | SEPT. 30 |
| Corporate acquisition | - | - | 2,393.2 |
| Net property acquisitions | 35.3 | 33.1 | 333.3 |
| Land acquisition and retention | 27.8 | 19.2 | 48.4 |
| Seismic evaluation | 24.8 | 14.6 | 4.9 |
| Well drilling, completion and equipping | 206.8 | 135.9 | 144.1 |
| Pipeline and production facilities | 124.3 | 66.6 | 56.5 |
| Reserve replacement expenditures | 419.0 | 269.4 | 2,980.4 |
| Midstream operations | 9.6 | 5.2 | - |
| Horizon Project | 22.3 | 16.6 | 9.9 |
| Abandonments | 6.8 | 11.9 | 19.8 |
| Head office equipment | 1.1 | 1.7 | 3.9 |
| Total Net Capital Expenditures | 458.8 | 304.8 | 3,014.0 |

| CAPITAL EXPENDITURES BY QUARTER | 2001 THREE MONTHS ENDED ($ Millions) | | |
|---|---|---|---|
| | MAR. 31 | JUNE 30 | SEPT. 30 |
| Corporate acquisition | - | - | - |
| Net property acquisitions | 190.7 | 55.5 | 24.6 |

| | | | |
|---|---|---|---|
| Land acquisition and retention | 27.7 | 21.5 | 35.8 |
| Seismic evaluation | 37.0 | 20.2 | 8.6 |
| Well drilling, completion and equipping | 227.2 | 153.0 | 148.6 |
| Pipeline and production facilities | 111.4 | 105.0 | 109.7 |
| Reserve replacement expenditures | 594.0 | 355.2 | 327.3 |
| Midstream operations | 28.9 | 6.8 | 16.1 |
| Horizon Project | 9.1 | 4.8 | 1.9 |
| Abandonments | 1.2 | (0.2) | 5.0 |
| Head office equipment | 1.5 | 1.4 | 1.8 |
| Total Net Capital Expenditures | 634.7 | 368.0 | 352.1 |



G. NON-RESERVE ACREAGE

The following table summarizes the Company's working interest holdings in core area non-reserve acreage earned by the Company as at December 31, 2002:

| | GROSS ACRES (thousands) | NET ACRES (thousands) |
|---|---|---|
| NORTH AMERICA | | |
| Alberta | 9,771 | 8,281 |
| British Columbia | 2,064 | 1,513 |
| Saskatchewan | 434 | 407 |
| Manitoba | 12 | 11 |
| UNITED KINGDOM | | |
| North Sea | 733 | 410 |
| OFFSHORE WEST AFRICA | | |
| Angola | 1,220 | 610 |
| Cote d'Ivoire | 452 | 333 |
| Total | 14,686 | 11,566 |

SELECTED FINANCIAL INFORMATION

The following table summarizes the consolidated financial statements of the Company, which follows the full cost method of accounting for crude oil and natural gas operations:

| | YEAR ENDED DECEMBER 31 | | | |
|---|---|---|---|---|
| | 2002 | 2001(1) | 2000(1) | 1999 |
| | ($ millions, except per share information) | | | |
| Revenues (net of royalties) | 3,482.9 | 3,008.5 | 2,754.4 | 1,103.6 |
| Cash flow from operations attributable to common shareholders | 2,254.0 | 1,920.0 | 1,883.6 | 723.5 |
| Per common share - basic | 17.63 | 15.83 | 16.14 | 6.96 |
| - diluted | 16.99 | 15.23 | 15.64 | 6.85 |
| Net earnings attributable to common shareholders | 569.8 | 642.6 | 767.1 | 219.5 |
| Per common share - basic | 4.46 | 5.30 | 6.57 | 2.11 |
| - diluted | 4.31 | 5.17 | 6.39 | 2.08 |
| Total assets | 13,358.9 | 8,966.9 | 7,753.5 | 4,850.5 |
| Total long-term debt | 4,074.0 | 2,669.2 | 2,454.5 | 2,156.8 |

| | 2002 THREE MONTHS ENDED | | |
|---|---|---|---|
| | MARCH 31 | JUNE 30 | SEPT. 30 |
| | ($ millions, except per share information) | | |
| Revenues (net of royalties) | 626.5 | 735.5 | 1,004.9 |
| Net earnings attributable to common shareholders | 98.9 | 145.2 | 117.4 |
| Per common share - basic | 0.81 | 1.18 | 0.88 |
| - diluted | 0.79 | 1.09 | 0.86 |

| | 2001 THREE MONTHS ENDED(1) | | |
|---|---|---|---|
| | MARCH 31 | JUNE 30 | SEPT. 30 |
| | ($ millions, except per share information) | | |
| Revenues (net of royalties) | 903.5 | 815.5 | 706.3 |

| | | | |
|---|---|---|---|
| Net earnings attributable to common shareholders | 221.8 | 286.6 | 81.3 |
| Per common share - basic | 1.82 | 2.37 | 0.67 |
| - diluted | 1.77 | 2.23 | 0.66 |

(1) Restated for change in accounting policy with respect to foreign currency translation.

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## MARKET FOR CANADIAN NATURAL RESOURCES LIMITED SECURITIES

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

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, beginning January 22, 2001 and ending January 21, 2002, to purchase for cancellation up to 6,114,726 common shares of the Company, being 5 per cent of the 122,294,533 common shares of the Company outstanding on January 17, 2001. During this period, 2,537,800 common shares were purchased for cancellation at an average price of $44.61.

On January 21, 2002, 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, beginning January 23, 2002 and ending January 22, 2003, to purchase for cancellation up to 6,060,180 common shares of the Company, being 5 per cent of the 121,203,603 common shares of the Company outstanding on January 18, 2002. No common shares were purchased during this program.

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

On January 22, 2003, 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, beginning January 24, 2003 and ending January 23, 2004, to purchase for cancellation up to 6,692,799 common shares of the Company, being 5 per cent of the 133,855,988 common shares of the Company outstanding on January 17, 2003. As at the date hereof 865,600 common shares were purchased for cancellation.

## DIVIDEND HISTORY

Prior to 2001, dividends had not been paid on the common shares of the Company. On January 17, 2001 the Board of Directors approved a dividend policy for the payment of a regular quarterly dividend of $0.10 per common share. On February 25, 2002 the Board of Directors approved an increase in the quarterly dividend to $0.125 per common share commencing with the dividend payable April 1, 2002. On February 20, 2003 the Board of Directors approved a further increase in the quarterly dividend to $0.15 per common share commencing with the dividend payable April 1, 2003. These dividends are payable in January, April, July and October of each year. The dividend policy of the Company continues to be 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 are set forth below:

| NAME | POSITION PRESENTLY HELD | PRINCIPAL OCCUPATION DURING PAST 5 YEARS |
|---|---|---|
| N. Murray Edwards<br>Calgary, Alberta | Vice-Chairman and Director(3)(5) | President, Edco Financial Holdings Ltd. management and consulting company). Has continuously as a director of the Compan since September 1988. |
| Ambassador Gordon D. Giffin<br>Atlanta, Georgia | Director(1)(2) | Senior Partner, McKenna Long & Aldridge since May 2001; prior thereto United Sta to Canada. Has served continuously as a director of the Company since May 2002. |
| James T. Grenon<br>Calgary, Alberta | Director(2)(4) | Managing Director, TOM Capital Associate investment company). Has served continuo director of the Company since September |
| John G. Langille<br>Calgary, Alberta | President and Director | Officer of the Company. Has served conti director of the Company since June 1982. |
| Keith A.J. MacPhail<br>Calgary, Alberta | Director(3)(5) | Chairman and President, Bonavista Petrol November 1997. Has served continuously a the Company since October 1993. |
| Allan P. Markin<br>Calgary, Alberta | Chairman and Director | Chairman of the Company. Has served cont director of the Company since January 19 |
| James S. Palmer, C.M., Q.C.<br>Calgary, Alberta | Director(1)(2)(3)(4) | Chairman, Burnet, Duckworth & Palmer LLP served continuously as a director of the 1997. |
| Dr. Eldon R. Smith, M.D.<br>Calgary, Alberta | Director(4)(5) | Professor and Former Dean, Faculty of Me University of Calgary. Has served conti director of the Company since May 1997. |
| David A. Tuer<br>Calgary, Alberta | Director(1)(3) | Chairman, Calgary Health Region since Oc thereto President and Chief Executive Of Energy Corporation. Has served continuou of the Company since May 2002. |
| Steve W. Laut<br>Calgary, Alberta | Chief Operating Officer | Officer of the Company |
| Brian L. Illing | Executive | Officer of the Company |

| | | |
|---|---|---|
| Calgary, Alberta | Vice-President, Exploration | |
| Real M. Cusson<br>Calgary, Alberta | Senior Vice-President, Marketing | Officer of the Company |
| Real J. H. Doucet<br>Calgary, Alberta | Senior Vice-President, Oil Sands | Officer of the Company since October 200<br>director of various divisions at Suncor |
| Allen M. Knight<br>Calgary, Alberta | Senior Vice-President, International & Corporate Development | Officer of the Company |
| Tim S. McKay<br>Calgary, Alberta | Senior Vice-President, Operations | Officer of the Company |



| NAME | POSITION PRESENTLY HELD | PRINCIPAL OCCUPATION DURING PAST 5 YEARS |
|---|---|---|
| Douglas A. Proll<br>Calgary, Alberta | Senior Vice-President, Finance | Officer of the Company since April 20<br>Vice President Finance and Treasurer of<br>Ltd. until August 2000 and most recently<br>President Finance and Business Developme<br>Husky Energy Inc. from August 2000 to Fe |
| Lyle G. Stevens<br>Calgary, Alberta | SeniorVice-President, Exploitation | Officer of the Company |
| Mary-Jo Case<br>Calgary, Alberta | Vice President, Land | Officer of the Company since May 2002; p<br>Co-ordinator Land at PanCanadian Petrole<br>1999 and most recently Manager Commercia<br>Ventures and Land at PanCanadian Petrole<br>Limited 1999 to 2002. |
| William R. Clapperton<br>Calgary, Alberta | Vice-President, Regulatory, Stakeholder and Environmental Affairs | Officer of the Company since January 200<br>Manager, Surface Land and Environment fo |
| Cameron S. Kramer<br>Calgary, Alberta | Vice President, Field Operations | Officer of the Company since September 2<br>Production Engineer of the Company until<br>most recently Manager, Field Operations<br>Company from April 2000 to September 200 |
| Bruce E. McGrath<br>Calgary, Alberta | Corporate Secretary | Officer of the Company |

(1) Member of the Nominating and Corporate Governance Committee
(2) Member of the Audit Committee
(3) Member of the Reserves Committee

(4) Member of the Compensation Committee
(5) Member of the Safety, Health and Environmental Committee

All directors stand for election at each Annual General Meeting of CNRL shareholders. All of the current directors are standing for election at the Annual General Meeting of shareholders scheduled for May 8, 2003.

There are potential conflicts of interest to which the directors and officers of the Company may become subject in connection with the operations of the Company. Some of the directors and officers have been and will continue to be engaged in the identification and evaluation of businesses and assets with a view to potential acquisition of interests on their own behalf and on behalf of other corporations, and situations may arise where the directors and officers will be in direct competition with the Company. Conflicts, if any, will be subject to the procedures and remedies under the BUSINESS CORPORATIONS ACT (Alberta).

As at December 31, 2002, 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 5.7 per cent of the total outstanding common shares (approximately 7.4 per cent after the exercise of options pursuant to the Company's stock option plan).

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ADDITIONAL INFORMATION

Additional information including Directors' and Executive Officers' remuneration, principal holders of the Company's securities, options to purchase the Company's securities and interest of insiders in material transactions is contained in the Company's Notice of Annual General Meeting and Information Circular dated March 28, 2003 in connection with the Annual General Meeting of Shareholders of CNRL to be held on May 8, 2003 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 Management Discussion and Analysis and comparative Consolidated Financial Statements for the most recently completed fiscal year ended December 31, 2002 found on pages 32 to 49 and 50 to 70 respectively, of the 2002 Annual Report to the Shareholders, which information is incorporated herein by reference.

The Company shall provide to any person, upon request to the Corporate Secretary of the Company:

(a) when securities of the Company 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 the Company, 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 consolidated financial statements of the Company for its most recently completed financial year together with the accompanying report of the auditor and one copy of any interim consolidated financial statements of the issuer subsequent to the consolidated financial statements for its most recently completed financial year,

(iii) one copy of the information circular of the Company 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 the Company may require the payment of a reasonable charge if a person who is not a security holder of the issuer makes the request.

For additional copies of this Annual Information Form 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

DOCUMENT 2

MANAGEMENT'S
DISCUSSION & ANALYSIS

Canadian Natural Resources is a Canadian based senior independent energy company engaged in the acquisition, exploration, development, production, marketing and sale of oil and natural gas. The Company initiates, operates and maintains a large working interest in a majority of the prospects in which it participates. The Company's principal core areas of oil and natural gas operations are in the Western Canadian Sedimentary Basin, the United Kingdom sector of the North Sea and Offshore West Africa.

## MANAGEMENT'S DISCUSSION & ANALYSIS

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS
Certain statements in the Management's Discussion and Analysis for Canadian Natural Resources Limited (the "Company") may constitute forward-looking statements within the meaning of the United States Private Litigation Reform Act of 1995. These forward-looking statements can generally be identified as such

because of the context of the statements including words such as the Company believes, anticipates, expects, plans, estimates or words of a similar nature.

The forward-looking statements are based on current expectations and are subject to known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements of the Company, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; foreign currency exchange rates; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; the ability of the Company to implement its business strategy, including exploration and development activities; the ability of the Company to complete its capital programs; the ability of the Company to transport its products to market; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the availability and cost of financing; the success of exploration and development activities; production levels; uncertainty of reserve estimates; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations); site restoration costs; and other circumstances affecting revenues and expenses. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors, and management's course of action would depend upon its assessment of the future considering all information then available.

Statements relating to reserves are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future.

Readers are cautioned that the foregoing list of important factors is not exhaustive. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. The Company assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.

## MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis of the financial condition and results of operations of the Company should be read in conjunction with the Company's audited consolidated financial statements and related notes for the year ended December 31, 2002. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). A reconciliation of Canadian GAAP to United States GAAP is included in note 16 to the consolidated financial statements. All dollar amounts are referenced in Canadian dollars, except when noted otherwise. The calculation of barrels of oil equivalent ("boe") is based on a conversion ratio of six thousand cubic feet of natural gas to one barrel of oil to estimate relative energy content.

The following discussion details the Company's 2002 financial results compared to 2001 and 2000, including its capital program, and outlook for 2003.

## OBJECTIVE AND STRATEGY

The Company's objective is to increase cash flow, net earnings, and oil and natural gas production and reserves through the development of its existing oil and natural gas properties and by the discovery and acquisition of new reserves.

The Company accomplishes this by having a defined growth and value enhancement plan for each of its products and segments. The Company effectively allocates its capital by maintaining:

- Balance between its products, namely natural gas, light oil, Pelican Lake oil (1), primary heavy oil and thermal heavy oil;
- Balance between near-, mid- and long-term projects;
- Balance between acquisitions, exploitation and exploration; and
- Balance between sources of debt and a strong balance sheet.

Strategic acquisitions, such as the acquisition of Rio Alto Exploration Ltd. ("Rio Alto"), are a key component of the Company's strategy.

Cost control is central to the Company's strategy. By controlling costs consistently throughout all industry cycles, the Company is able to achieve continued growth. Cost control is attained by core area domination and by operating at a high working interest.

(1) Pelican Lake oil is 14-17(0) API oil, but receives medium quality crude netbacks due to exceptionally low operating costs and low royalty rates.



## MANAGEMENT'S DISCUSSION & ANALYSIS

The year ended December 31, 2002 was another successful year in the execution of the Company's strategy. The highlights were:

- Acquired Rio Alto;
- Acquired North Sea properties that provide the Company with the level of operatorship and working interests in the North Sea necessary to effectively control costs;
- Commenced production from the Espoir field offshore Cote d'Ivoire;
- Successfully delineated the Baobab field located offshore Cote d'Ivoire;
- Received government approval for development of the Baobab field;
- Received regulatory approval for high-pressure steaming at Primrose, Alberta;
- Submitted regulatory application for the Horizon Oil Sands Project ("Horizon Project");
- Signed a Production Sharing Agreement for Block 16, offshore Angola and Block CI-400 offshore Cote d'Ivoire; and
- Successfully issued public debt to balance our sources of debt.

### ACQUISITION OF RIO ALTO

The Company paid cash of $850.0 million and issued 10,008,218 common shares to acquire all of the issued and outstanding common shares of Rio Alto by way of a plan of arrangement. This was a strategic acquisition by the Company as it strengthened the Company's natural gas production in North America and added a new natural gas core region in Northwest Alberta that will provide the opportunity for significant future natural gas volumes. The Rio Alto acquisition is included in the results of operations commencing July 1, 2002.

CASH FLOW AND NET EARNINGS

| Financial Highlights ($ millions, except per share amounts) | 2002 | 200 |
|---|---|---|
| Revenue | $ 4,083.2 | $ 3,58 |
| Cash flow from operations attributable to common shareholders (2) | $ 2,254.0 | $ 1,92 |
| Per common share - basic | $ 17.63 | $ 15 |
| - diluted | $ 16.99 | $ 15 |
| Net earnings attributable to common shareholders (3) | $ 569.8 | $ 64 |
| Per common share - basic | $ 4.46 | $ 5 |
| - diluted | $ 4.31 | $ 5 |
| Business combinations | $ 2,393.2 | $ |
| Capital expenditures, net of dispositions | $ 1,676.2 | $ 1,88 |

(1) Restated for change in accounting policy (see consolidated financial statements - note 2) and to conform to current year presentation.
(2) After dividend on preferred securities.
(3) After dividend and revaluation of preferred securities.

[Graphic Omitted]

CASH FLOW FROM OPERATIONS ATTRIBUTABLE TO COMMON SHAREHOLDERS ($ millions)

| | |
|---|---|
| 98 | 444.2 |
| 99 | 723.5 |
| 00 | 1,883.6 |
| 01 | 1,920.0 |
| 02 | 2,254.0 |

NET EARNINGS PER SHARE ATTRIBUTABLE TO COMMON SHAREHOLDERS* ($ millions)

| | |
|---|---|
| 98 | 0.40 |
| 99 | 2.11 |
| 00 | 6.57 |
| 01 | 5.30 |
| 02 | 4.46 |

* Restated for change in accounting policy

NET EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS* ($ millions)

| | |
|---|---|
| 98 | 39.4 |
| 99 | 219.5 |
| 00 | 767.1 |
| 01 | 642.6 |
| 02 | 569.8 |

* Restated for change in accounting policy

RETURN ON AVERAGE COMMON SHAREHOLDER'S EQUITY* (%)

| | |
|---|---|
| 98 | 3.2 |
| 99 | 14.5 |
| 00 | 31.6 |
| 01 | 18.8 |
| 02 | 13.8 |

* Restated for change in accounting policy

Cash flow from operations attributable to common shareholders increased 17% to $2,254.0 million ($17.63 per common share), up from $1,920.0 million ($15.83 per common share) in 2001 and $1,883.6 million ($16.14 per common share) in 2000. The increase in cash flow resulted primarily from increased production volumes offset by lower natural gas prices. In 2002, the Company's average price per barrel of oil and liquids increased to $29.76 from $24.31 in 2001 (2000 - $29.99). Production volumes increased 17% to 420,722 boe/d from 359,347 boe/d in 2001 (2000 - 305,987 boe/d).

Net earnings attributable to common shareholders decreased 11% in 2002 to $569.8 million, down from $642.6 million in 2001 and down from $767.1 million in 2000. The decrease in net earnings resulted from the natural gas weighted acquisition of Rio Alto, higher depletion, depreciation and amortization costs and increased future income tax expense.

| OPERATING HIGHLIGHTS | 2002 | 2001(1) | |
|---|---|---|---|
| OIL AND LIQUIDS ($/bbl, except daily production) | | | |
| Daily production (bbls/d) | 215,335 | 206,323 | |
| Sales price | $ 29.76 | $ 24.31 | $ |
| Royalties | 3.16 | 2.17 | |
| Production expense | 8.45 | 7.64 | |
| Netback | $ 18.15 | $ 14.50 | $ |
| NATURAL GAS ($/mcf, except daily production) | | | |
| Daily production (mmcf/d) | 1,232 | 918 | |
| Sales price | $ 3.76 | $ 5.16 | $ |
| Royalties | 0.78 | 1.25 | |
| Production expense | 0.57 | 0.51 | |
| Netback | $ 2.41 | $ 3.40 | $ |
| BARREL OF OIL EQUIVALENT ($/boe, except daily production) | | | |
| Daily production (boe/d) | 420,722 | 359,347 | |
| Sales price | $ 26.25 | $ 27.15 | $ |
| Royalties | 3.91 | 4.42 | |
| Production expense | 5.99 | 5.69 | |
| Netback | $ 16.35 | $ 17.04 | $ |

(1) Restated to conform to current year presentation.

REVENUE

Product Prices

| | 2002 | 2001 | |
|---|---|---|---|
| OIL AND LIQUIDS ($/bbl) | | | |
| North America | $ 27.04 | $ 21.00 | $ |

| | | | |
|---|---|---|---|
| North Sea | $ 39.79 | $ 38.66 | $ |
| Offshore West Africa | $ 40.10 | $ 33.57 | $ |
| Company average | $ 29.76 | $ 24.31 | $ |
| NATURAL GAS ($/mcf) | | | |
| North America | $ 3.78 | $ 5.19 | $ |
| North Sea | $ 2.75 | $ 2.51 | $ |
| Offshore West Africa | $ 4.82 | $ - | $ |
| Company average | $ 3.76 | $ 5.16 | $ |
| PERCENTAGE OF REVENUE (excluding midstream revenue) | | | |
| Oil and liquids | 58.1% | 51.5% | |
| Natural gas | 41.9% | 48.5% | |





ANALYSIS OF CHANGES IN REVENUE (excluding midstream operations)

| | | CHANGES DUE TO | | | CHANGES |
|---|---|---|---|---|---|
| ($ MILLIONS) | 2000 | VOLUMES | PRICES | 2001 | VOLUMES |
| NORTH AMERICA | | | | | |
| Oil and liquids | $ 1,591.0 | $ 122.5 | $ (434.1) | $ 1,279.4 | $ 23.0 |
| Natural gas | 1,314.1 | 183.3 | 220.0 | 1,717.4 | 565.1 |
| | 2,905.1 | 305.8 | (214.1) | 2,996.8 | 588.1 |
| NORTH SEA | | | | | |
| Oil and liquids | 280.8 | 309.5 | (78.5) | 511.8 | 37.0 |
| Natural gas | 2.0 | 14.3 | (5.1) | 11.2 | 13.6 |
| | 282.8 | 323.8 | (83.6) | 523.0 | 50.6 |
| OFFSHORE WEST AFRICA | | | | | |
| Oil and liquids | 34.6 | 22.1 | (15.1) | 41.6 | 41.5 |
| Natural gas | - | - | - | - | 2.2 |
| | 34.6 | 22.1 | (15.1) | 41.6 | 43.7 |
| TOTAL | | | | | |
| Oil and liquids | 1,906.4 | 454.1 | (527.7) | 1,832.8 | 101.5 |
| Natural gas | 1,316.1 | 197.6 | 214.9 | 1,728.6 | 580.9 |
| | $ 3,222.5 | $ 651.7 | $ (312.8) | $ 3,561.4 | $ 682.4 |

Oil and natural gas revenue rose 13% to $4,031.2 million from $3,561.4 million in 2001 (2000 - $3,222.5 million). In 2002, 17% of the Company's oil and natural gas revenue was generated outside of North America (2001 - 16%, 2000 - 10%), with the North Sea accounting for 15% of these revenues, in both 2002 and 2001 (2000 - 9%) and Offshore West Africa accounting for 2%, up from 1% in 2001 (2000 - 1%). Revenue from the sale of natural gas accounted for 42% of oil and natural gas revenue, down from 49% in 2001 (2000 - 41%).

Oil and liquids pricing realized by the Company is directly correlated with world oil pricing and heavy oil differentials. The realized oil and liquids price earned by the Company in 2002 increased 22% to average $29.76 per bbl for the year, up from $24.31 per bbl in 2001 (2000 - $29.99 per bbl). World oil prices were low in the beginning of 2002 but increased throughout the year due to supply and demand fundamentals, general market uncertainty surrounding tension in the Middle East, and disruptions in the supply of oil from Venezuela. The West Texas Intermediate ("WTI") oil price increased 1% to average US $26.11 per bbl, up from US $25.91 per bbl in 2001 (2000 - US $30.20 per bbl). During the same time, the heavy oil differential averaged US $6.50 per bbl, down from US $10.73 per bbl in 2001 (2000 - US $8.23 per bbl). Heavy oil differentials were lower than the historical 10-year average 30% discount to WTI pricing due to a lower supply of heavy oil from western Canadian producers. The higher heavy oil differentials experienced in 2001 were affected by the temporary shutdown of a heavy oil refinery in the US mid-west and reduced demand for heavy oil.

Natural gas prices decreased 27% to average $3.76 per mcf, down from $5.16 per mcf in 2001 (2000 - $4.53 per mcf), due to lower demand and higher storage levels in the first half of 2002. Prices in 2001 were impacted by the increased demand for natural gas due to cold winter temperatures, low inventory levels, increased natural gas-fired power generation and increased export capacity. AECO prices averaged $4.07 per mmbtu in 2002 compared to $6.25 per mmbtu in the year 2001 (2000 - $5.02 per mmbtu). NYMEX natural gas prices per mmbtu averaged US $3.25 in 2002 compared to US $4.38 in 2001 (2000 - $3.91).

The Company uses certain financial instruments to protect against the downside commodity prices received on the sale of certain oil and natural gas production and to protect its capital program. The price realized from the sale of oil was reduced by $1.46 per bbl in 2002 compared to an increase of $0.86 per bbl in 2001 (2000 - reduction of $1.89 per bbl), as a result of the financial instruments. The price realized from the sale of natural gas was reduced by $0.01 per mcf in 2002 compared to a reduction of $0.29 per mcf in 2001 (2000 - reduction of $0.39 per mcf), as a result of the financial instruments.

As part of its overall risk management program, the Company has entered into "costless collars" on a portion of its oil and natural gas production. These financial instruments are summarized in note 12 to the consolidated financial statements.





DAILY PRODUCTION

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| OIL AND LIQUIDS (bbls/d) | | | |
| North America | 169,675 | 166,675 | 154,331 |
| North Sea | 38,876 | 36,252 | 17,195 |
| Offshore West Africa | 6,784 | 3,396 | 2,065 |

| | | | |
|---|---|---|---|
| Total | 215,335 | 206,323 | 173,591 |
| NATURAL GAS (mmcf/d) | | | |
| North America | 1,204 | 906 | 793 |
| North Sea | 27 | 12 | 1 |
| Offshore West Africa | 1 | - | - |
| Total | 1,232 | 918 | 794 |
| PRODUCT MIX | | | |
| Light oil and liquids | 20.8% | 20.7% | 18.1% |
| Pelican Lake oil | 7.0% | 9.7% | 9.4% |
| Primary heavy oil | 14.0% | 15.8% | 18.0% |
| Thermal heavy oil | 9.4% | 11.2% | 11.2% |
| Natural gas | 48.8% | 42.6% | 43.3% |

The Company's daily oil and liquids production increased 4% to average 215,335 bbls in 2002 from 206,323 bbls in 2001 (2000 - 173,591 bbls). Oil and liquids production increased for all segments from the year ended December 31, 2001. The increase in North American production is attributable to additional heavy oil drilling activity and property acquisitions in the Company's core operating regions. Oil production in the North Sea increased as a result of the acquisition of additional interests in the northern sector of the North Sea in 2002. Offshore West Africa oil production increased from 2001 as a result of production commencing from the Company's operated Espoir field, located offshore Cote d'Ivoire, in February 2002.

Natural gas continues to represent the Company's largest product offering, accounting for nearly 49% of the Company's total production in 2002 compared to 43% of total production in both 2001 and 2000. North America accounts for over 98% of the Company's natural gas production in 2002 and 2001 (2000 - 100%). Daily natural gas production increased 34% to 1,232 mmcf from 918 mmcf in 2001 (2000 - 794 mmcf). Natural gas production increased from the comparable periods due to development of the Ladyfern field and the 2002 mid-year acquisition of Rio Alto. Natural gas production from Rio Alto properties averaged 376 mmcf/d over the last half of 2002. The Ladyfern field averaged 168 mmcf/d of natural gas production during 2002, up from 40 mmcf/d in 2001. Natural gas production increased in the North Sea due to the acquisition of additional interests in the Banff and Kyle fields.

[GRAPHIC OMITTED]

NATURAL GAS PRODUCTION (mmcf/d)

| | |
|---|---|
| 98 | 673 |
| 99 | 721 |
| 00 | 794 |
| 01 | 918 |
| 02 | 1,232 |

CRUDE OIL AND NGLs PRODUCTION (mbbls/d)

| | |
|---|---|
| 98 | 76 |
| 99 | 87 |
| 00 | 174 |
| 01 | 206 |
| 02 | 215 |

ROYALTIES

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| OIL AND LIQUIDS ($/bbl) | | | |
| North America | $ 3.42 | $ 2.22 | $ 3.17 |
| North Sea | $ 2.30 | $ 2.10 | $ 2.40 |
| Offshore West Africa | $ 1.35 | $ 0.93 | $ - |
| Company average | $ 3.16 | $ 2.17 | $ 3.05 |
| NATURAL GAS ($/mcf) | | | |
| North America | $ 0.80 | $ 1.26 | $ 1.08 |
| Offshore West Africa | $ 0.15 | $ - | $ - |
| Company average | $ 0.78 | $ 1.25 | $ 1.08 |
| Company average ($/boe) | $ 3.91 | $ 4.42 | $ 4.51 |
| PERCENTAGE OF REVENUE (excluding financial instruments) | | | |
| Oil and liquids | 10.1% | 9.3% | 9.6% |
| Natural gas | 20.8% | 22.8% | 22.0% |

Oil and liquids royalties in North America increased to $3.42 per bbl, up from $2.22 per bbl in 2001 (2000 - $3.17 per bbl), due to changes in oil prices. Oil and liquids royalties in North America increased as a percentage of revenue as a result of certain primary and thermal heavy oil projects that were subject to a lower royalty structure reaching payout and becoming subject to higher government royalty rates. The majority of the Company's oil sands projects continue to benefit from reduced royalty rates as a result of the Alberta program to promote development of oil sands resources, which provides a reduced royalty rate until an oil sands project recovers its capital costs. In 2002, North Sea oil royalties increased to $2.30 per bbl from $2.10 per bbl in 2001 (2000 - $2.40 per bbl). The increase per barrel and as a percentage of revenue is due to the acquisition of additional interests in the royalty paying Ninian, Murchison and Columba fields. In late November 2002, it was announced that royalties in the North Sea would be eliminated effective January 1, 2003. Offshore West Africa oil royalties increased from the prior year due to the Espoir field commencing production in February 2002. In 2001, the Kiame field in Angola was the only field on production and was on royalty holiday for a portion of that year.

Natural gas royalties for the Company decreased to $0.78 per mcf for the year 2002, down from $1.25 per mcf in 2001 (2000 - $1.08 per mcf), due to the overall decrease in natural gas prices. North American natural gas royalties are sensitive to price changes and increased as a percentage of revenue in 2001 due to the higher sales prices received. Natural gas royalties as a percentage of revenue decreased to 20.8% in 2002 from 22.8% of revenue in 2001 (2000 - 22.0%) due to lower average natural gas prices. In the North Sea, the Company's natural gas production is derived from the non-royalty paying Banff and Kyle fields.

PRODUCTION EXPENSE

| | 2002 | 2001(1) | 2000(1) |
|---|---|---|---|
| OIL AND LIQUIDS ($/bbl) | | | |
| North America | $ 6.73 | $ 7.05 | $ 6.45 |
| North Sea | $ 15.06 | $ 9.00 | $ 8.66 |
| Offshore West Africa | $ 13.63 | $ 21.77 | $ 20.41 |
| Company average | $ 8.45 | $ 7.64 | $ 6.84 |
| NATURAL GAS ($/mcf) | | | |

| | | | |
|---|---|---|---|
| North America | $ 0.55 | $ 0.50 | $ 0.44 |
| North Sea | $ 1.53 | $ 0.94 | $ 0.79 |
| Offshore West Africa | $ 1.81 | $ - | $ - |
| Company average | $ 0.57 | $ 0.51 | $ 0.44 |
| COMPANY AVERAGE ($/boe) | $ 5.99 | $ 5.69 | $ 5.02 |

(1) Restated to conform to current year presentation.





The decrease in 2002 North America oil and liquids production expense to $6.73 per bbl from $7.05 per bbl in 2001 (2000 - $ 6.45 per bbl) is primarily attributable to the decrease in natural gas prices. Natural gas is used to produce steam to heat the thermal oil formations to facilitate extraction in the Primrose area of Alberta. Production expense in 2001 was higher due to higher fuel and power costs incurred during the first half of the year. North Sea oil production expense increased in 2002 to $15.06 per bbl from $9.00 per bbl in 2001 (2000 - $8.66 per bbl), due to costs incurred as a result of the planned maintenance shutdowns of the Ninian North and Ninian Central platforms during the third quarter of 2002. Production expense in the North Sea also increased in 2002 as a result of costs incurred to rectify a natural gas pipeline blockage at Kyle experienced in the second quarter of 2002, and because the Columba B and D fields reached a production milestone during 2001, thereby giving rise to higher tariff rates on a go-forward basis. Offshore West Africa oil production expense decreased to $13.63 per bbl from $21.77 per bbl in 2001 (2000 - $ 20.41 per bbl) as a result of production ceasing from the higher production expense Kiame field and as a result of production commencing from the Espoir field.

Natural gas production expense for the year 2002 increased to $0.57 per mcf from $0.51 per mcf in 2001 (2000 - $0.44 per mcf), due to increased gathering and processing charges and increased toll rates on Ladyfern production in the first half of 2002.

MIDSTREAM

| ($ millions) | 2002 | 2001 | 2000 |
|---|---|---|---|
| Revenue | $ 52.0 | $ 27.4 | $ 38.1 |
| Operating costs | 14.1 | 11.2 | 8.7 |
| Operating cash flow | 37.9 | 16.2 | 29.4 |
| Depreciation | 7.6 | 3.8 | 1.8 |
| Segment earnings before taxes | $ 30.3 | $ 12.4 | $ 27.6 |

The Company's midstream assets consist of the 100% owned and operated ECHO pipeline, the 15% interest in the Cold Lake pipeline system, the 62% interest in the operated Pelican Lake pipeline, and the 50% interest in the 84 megawatt co-generation system located in the Primrose area. The midstream pipeline assets allow the Company to transport its own production volumes as well as earn third party revenue from excess capacity. The Company transports approximately 82% of its heavy oil through its pipelines to the international mainline liquid pipelines. These midstream assets enhance the Company's ability to control the full range of costs associated with the development and marketing of its heavy oil.

The increase in operating cash flow and segment earnings before taxes in 2002 was due to the expansion of the ECHO pipeline, as well as the increased interest in the Pelican Lake pipeline and the commencement of operations from the Cold Lake pipeline system in late December 2001. The increased pipeline revenues were partially offset by a decline in electricity revenue received from the sale of excess electricity from the Company's cogeneration system to the Alberta Power Pool.

DEPLETION, DEPRECIATION AND AMORTIZATION (1)

| ($ millions, except per boe amounts) | 2002 | 2001 | 2000 |
|---|---|---|---|
| North America | $ 1,032.8 | $ 747.1 | $ 585.9 |
| North Sea | 193.3 | 129.0 | 54.4 |
| Offshore West Africa | 80.5 | 23.9 | 2.5 |
| Expense | $ 1,306.6 | $ 900.0 | $ 642.8 |
| $/boe | $ 8.51 | $ 6.86 | $ 5.73 |

(1) DD&A excludes midstream operations.

Depletion, depreciation and amortization ("DD&A") increased in total and per boe to $1,306.6 million or $8.51 per boe from $900.0 million or $6.86 per boe in 2001 (2000 - $642.8 million or $5.73 per boe). This increase was due to the higher finding and development costs associated with natural gas exploration in North America, the allocation of the acquisition costs associated with Rio Alto, and future abandonment costs associated with the acquisition of additional interests in the North Sea. DD&A was further increased in 2002 as a result of the Company's decision to exit from its interests in Block 19, Angola, and from the Aje field, Nigeria. The decision to exit from Block 19, Angola was made after a technical review of the results of the Mariposa well where the Company held a 25% non-operated working interest. The decision to exit from the Aje field was based on a reinterpretation of seismic that showed the structural closures were greatly reduced from previous expectations. The reduction in likely oil-in-place and associated risk meant that the project failed to meet the Company's economic threshold. The Company charged all related capitalized costs in those countries, totaling $51 million, to DD&A during the second quarter of 2002.

ADMINISTRATION EXPENSE

| ($ millions, except per boe amounts) | 2002 | 2001 | 2000 |
|---|---|---|---|
| Gross cost | $ 147.2 | $ 109.9 | $ 67.8 |
| $/boe | $ 0.96 | $ 0.84 | $ 0.61 |
| Net expense | $ 61.3 | $ 37.6 | $ 27.2 |
| $/boe | $ 0.40 | $ 0.29 | $ 0.25 |





Gross administration expense increased to $0.96 per boe from $0.84 per boe in 2001 (2000 - $0.61 per boe) mainly due to higher staffing levels associated with the growth in production and the expanding asset base. Gross administration expense also increased as a result of the higher costs related to the assumption of operatorship of certain fields in the North Sea and the cost of relocating the majority of the Company's UK operations to Aberdeen during the fourth quarter 2002. Net administration expense, after operator recoveries and capitalized overhead relating to exploration and development in the North Sea and Offshore West Africa as well as the Horizon Project, increased to $0.40 per boe in 2002 from $0.29 per boe in 2001 (2000 - $0.25 per boe), due to the higher staffing levels and expanding asset base.

INTEREST EXPENSE

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Interest expense ($ millions) | $ 158.9 | $ 137.8 | $ 162.3 |
| $/boe | $ 1.03 | $ 1.05 | $ 1.45 |
| Average effective interest rate | 4.5% | 5.4% | 6.4% |

Interest expense increased in total to $158.9 million in 2002 from $137.8 million in 2001 (2000 - $162.3 million), due to higher average outstanding debt levels as a result of the acquisition of Rio Alto and other property acquisitions. Interest expense was consistent with 2000 as the overall increase in debt levels in the last half of 2002 was offset by the lower cost of borrowing. The impact of the higher debt levels was partially offset by the lower overall cost of borrowing of 4.5% in 2002 from 5.4% in 2001 (2000 - 6.4%). Interest expense per boe remained consistent at $1.03 per boe in 2002 compared to $1.05 per boe in 2001 as the higher interest expense was offset by increased production, but decreased from 2000 due to the increase in production and the lower cost of borrowing. The Company continues to benefit from the lower short-term interest rates as its fixed-rate debt accounts for only 40% of total debt outstanding (after interest rates swaps, see note 12 to the consolidated financial statements) as at December 31, 2002 (2001 - 21%, 2000 - 23%).

FOREIGN EXCHANGE

| ($ millions) | 2002 | 2001(1) | 2000(1) |
|---|---|---|---|
| Realized foreign exchange loss (gain) | $ 3.4 | $ (1.3) | $ (0.2) |
| Unrealized foreign exchange (gain) loss | (35.1) | 64.1 | 16.1 |
| | $ (31.7) | $ 62.8 | $ 15.9 |

(1) Restated for change in accounting policy (see consolidated financial statements - note 2).

Effective January 1, 2002, the Company retroactively adopted the Canadian Institute of Chartered Accountants' new accounting standard with respect to foreign currency translation. The new standard requires foreign exchange gains and losses on the Company's US dollar denominated debt to be expensed immediately rather than deferring and amortizing the gains and losses over the term of the related debt. The change in accounting policy was applied retroactively and foreign exchange losses for the year ended December 31, 2001 were increased by $48.1 million (2000 - $13.5 million). The majority of the foreign exchange amounts are due to the translation of the US dollar denominated debt.

The Company's US dollar denominated debt increased to US $1,968.0 million, up from US $899.0 million in 2001 and US $509.0 million in 2000. The increase in the US dollar denominated debt in 2002 was due to the following issuances:

- US $400 million of US dollar debt securities, maturing January 15, 2032, and bearing interest at 7.20%;
- US $350 million of US dollar debt securities, maturing October 1, 2012, and bearing interest at 5.45%; and

o US $350 million of US dollar debt securities, maturing June 30, 2033, and bearing interest at 6.45%.

US dollar denominated debt represented 76% of total debt outstanding at December 31, 2002 (2001 - 53%, 2000 - 31%). Due to the greater amount of US dollar denominated debt outstanding, the Company's net earnings were more affected by the fluctuations in the Canadian dollar. The US/Canadian dollar exchange rate fluctuated throughout 2002 due to economic and political uncertainties. The Canadian dollar averaged US $0.637 in 2002, down from US $0.646 in 2001 (2000 - US $0.673).

In order to mitigate a portion of the volatility associated with the Canadian dollar, the Company, effective July 1, 2002, designated certain US dollar denominated debt as a hedge against its net investment in US dollar based self-sustaining foreign operations. Accordingly, translation gains and losses on this US dollar denominated debt are included in the foreign currency translation adjustment in shareholders' equity in the consolidated balance sheets.





TAXES

| ($ millions, except for tax rates) | 2002 | 2001 | 2000 |
|---|---|---|---|
| Taxes other than income tax | | | |
| Current | $ 53.4 | $ 69.3 | $ 57.1 |
| Deferred | 9.5 | (0.2) | (7.6) |
| Total | $ 62.9 | $ 69.1 | $ 49.5 |
| Current income tax | | | |
| North Sea | $ (19.6) | $ 61.8 | $ 33.7 |
| Offshore West Africa | 6.0 | - | - |
| North America - Large Corporations Tax | 21.2 | 15.1 | 14.7 |
| Total | $ 7.6 | $ 76.9 | $ 48.4 |
| Future income tax | $ 401.0 | $ 282.5 | $ 464.0 |
| Effective income tax rate | 41.6% | 35.4% | 39.9% |

Taxes other than income tax consist of current and deferred petroleum revenue tax ("PRT"), other international taxes and provincial capital taxes. PRT is charged on certain fields in the North Sea at the rate of 50% of net operating income after certain deductions including abandonment expenditures. Taxes other than income tax decreased to $62.9 million or $0.41 per boe in 2002 from $69.1 million or $0.53 per boe in 2001 (2000 - $49.5 million or $0.44 per boe). The decrease in taxes other than income taxes was mainly due to the lower netback earned in the North Sea as a result of increased production costs. Taxes other than income taxes increased from the year 2000 due to a full year of production from the North Sea properties acquired in the Ranger Oil Limited ("Ranger") acquisition. North Sea PRT accounts for $51.1 million or $0.33 per boe in 2002 compared to $59.1 million or $0.45 per boe in 2001 (2000 - $33.3 million or $0.29 per boe).

In 2002, there was a recovery of current income tax in the North Sea of $19.6 million or $0.13 per boe compared to an income tax expense of $61.8 million or $0.47 per boe in 2001 (2000 - $33.7 million or $0.30 per boe). The decrease in the current income tax expense was partly due to the decision by the UK Government to increase the first year capital allowance rate for plant and machinery expenditures to 100% from the previous rate of 25%. The recovery of current income tax also resulted from the settlement of certain outstanding matters from prior years. Offshore West Africa current income tax expense increased from the prior year due to the commencement of operations at the Espoir field located offshore Cote d'Ivoire in February 2002. The Company did not incur any cash Canadian federal income taxes in 2002. It is anticipated that, based on the current availability of $3.1 billion of tax pools in Canada at the end of 2002 and the current pricing, the Company could be cash taxable in Canada in 2003. The Company is liable for the payment of federal Large Corporations Tax ("LCT"). LCT increased to $21.2 million or $0.14 per boe from $15.1 million or $0.11 per boe (2000 - $14.7 million, $0.13 per boe) due to the higher taxable capital base as a result of increased debt levels and shareholders' equity associated with the acquisition of Rio Alto.

The Company's future income tax provision for 2002 increased to $401.0 million ($2.61 per boe) from $282.5 million ($2.15 per boe) in 2001 (2000 - $464.0 million or $4.14 per boe) due to the increase in net earnings before tax. Future income tax expense for the year ended December 31, 2002 also increased over the prior year due to the introduction in the UK of a 10% supplementary charge on profits from North Sea oil and natural gas production. The supplementary charge is in addition to the current corporate tax rate of 30% and excludes any deduction for financing costs. As a result of this additional charge, the future income tax liability in the North Sea was increased by $34 million. The increase in the North Sea future income tax liability was partially offset by a $26 million decrease in the North American future income tax liability as a result of a reduction in a Canadian province's corporate income tax rate in the second quarter of 2002. In 2001, the North American future income tax liability was reduced by $63 million as a result of reductions in Canadian provinces' corporate income tax rates. Future income taxes also increased in 2002 because of the increased capital allowance rates in the North Sea, resulting in a lower current tax expense and a higher future income tax expense. Future income taxes in 2000 were higher due to higher product netbacks and higher current income tax rates in Canada.

The Company's effective tax rate increased to 41.6% in 2002 from 35.4% in 2001 (2000 - 39.9%). The increase is a result of the introduction of the 10% supplementary charge on profits from North Sea oil and natural gas production and the reductions in certain Canadian provinces' corporate income tax rates during 2001.





## LIQUIDITY AND CAPITAL RESOURCES

| ($ millions, except ratios) | 2002 | 2001(1) | 2000(1) |
|---|---|---|---|

| | | | |
|---|---|---|---|
| Working capital deficit | $ 13.8 | $ 5.6 | $ 77.3 |
| Long-term debt | 4,074.0 | 2,669.2 | 2,454.5 |
| Net debt | $ 4,087.8 | $ 2,674.8 | $ 2,531.8 |
| | | | |
| Shareholders' equity | | | |
| Preferred securities | $ 126.4 | $ 127.4 | $ 119.9 |
| Share capital | 2,303.8 | 1,698.3 | 1,692.6 |
| Retained earnings | 2,414.3 | 1,908.5 | 1,390.6 |
| Foreign currency translation adjustment | 23.6 | 72.8 | - |
| Total | $ 4,868.1 | $ 3,807.0 | $ 3,203.1 |
| | | | |
| Debt to cash flow (2) | 1.8x | 1.4x | 1.3x |
| Debt to book capitalization | 45.6% | 41.2% | 43.4% |
| Debt to market capitalization | 38.9% | 34.9% | 32.1% |
| After tax return on average common shareholders' equity (2) | 13.8% | 18.8% | 31.6% |
| After tax return on average capital employed (2) | 8.9% | 12.0% | 18.1% |

(1) Restated for change in accounting policy (see consolidated financial statements - note 2).
(2) Based on trailing 12-month period and does not include amounts related to acquired assets for the six-month period prior to June 30, 2002.

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

LONG-TERM DEBT

Long-term debt at December 31, 2002 amounted to $4,074 million and reflected a 1.8x debt to cash flow ratio and a debt to book capitalization of 45.6%. These ratios are within the Company's guidelines for balance sheet management.

At December 31, 2002 the Company had:

- Approximately $1.3 billion of available unused bank credit facilities;
- A fixed/floating interest rate mix of 40%/60%;
- An overall average cost of borrowing of approximately 4.5%;
- 76% of borrowings denominated in US dollars; and
- 76% of total long-term debt is non-bank based borrowing with an average maturity of 15.6 years.

During 2002, the Company issued US dollar debt securities and used the proceeds from the issuances to repay bank indebtedness. In January 2002, the Company issued US $400 million of 30-year US dollar debt securities maturing January 15, 2032, bearing interest at 7.20%. In September 2002, the Company issued US $350 million of ten-year US dollar debt securities maturing October 1, 2012, bearing interest at 5.45% and US $350 million of 30-year US dollar debt securities maturing June 30, 2033, bearing interest at 6.45%. Subsequent to these issuances, the Company entered into interest rate swap contracts that convert the fixed rate interest coupon into a floating interest rate (see consolidated financial statements - note 12). The Company has US $300 million remaining on a US $1 billion shelf prospectus filed on August 16, 2002 that allows for the issue of debt securities until September 2004. In addition, the Company maintains a shelf prospectus in Canada for the offering of up to $1 billion of medium-term notes in Canada. If issued, these securities will bear interest as determined at the date of issuance. Future offerings under the shelf prospectuses will provide flexibility to the Company's debt investment base, extend maturities and provide balance in the fixed to floating interest rate mix.

The ratings of the Company's debt securities and its relationships with principal banks are extremely important to the Company as it continues to expand and grow. Hence, the Company's management will continually undertake to strengthen its balance sheet and financial position. The Company's debt securities are rated "Baa1" by Moody's Investor Services Inc., "BBB+" by Standard & Poors Corporation and "BBB(high)" by Dominion Bond Rating Services Limited.

As at December 31, 2002, the Company had unsecured bank credit facilities of $2,275 million compared to $1,840 million at the close of 2001 (2000 - $2,800 million). During 2002, the Company repaid and cancelled a $725 million credit and term loan facility and a US $150 million credit and term loan facility. At December 31, 2002, the Company had approximately $1.3 billion of unutilized bank credit lines available to it, in addition to funds that are available through the Company's Canadian and US shelf prospectuses.





## SHARE CAPITAL

The Company issued 10.0 million common shares at an attributed value of $522.4 million as part of the consideration to acquire Rio Alto. A further 2.5 million shares were issued from the exercise of stock options throughout 2002 for proceeds of $82.1 million. In 2001, 1.5 million common shares from the exercise of stock options and warrants were issued for proceeds of $45.5 million. In 2000, 3.2 million common shares were issued from the exercise of stock options for proceeds of $65.3 million and 7.6 million common shares were issued at an attributed value of $358.0 million as part of the consideration to acquire Ranger.

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

In January 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. As at January 21, 2002, the Company had purchased 2,537,800 common shares, of the allowable 6,114,726 common shares for a total cost of $113.3 million. In January 2002, the Company renewed its Normal Course Issuer Bid. No common shares were purchased under the renewed Normal Course Issuer Bid in the period ended January 23, 2003.

In January 2003, the Company renewed its Normal Course Issuer Bid, allowing the Company to purchase up to 6,692,799 common shares or 5% of the Company's outstanding common shares on the date of announcement, during the 12-month period beginning January 24, 2003 and ending January 23, 2004. As at February 26, 2003, 175,600 common shares had been purchased under the Normal Course Issuer Bid for a total cost of $8.3 million.

In January 2001, the Company announced a regular quarterly dividend of $0.10 per common share payable in January, April, July and October of each year. In February 2002, the Board of Directors increased the Company's regular quarterly dividend to $0.125 per common share. In February 2003, the Board of Directors declared a 20% increase in the regular quarterly dividend to $0.15 per common share, or $0.60 per share per annum, commencing with the April 1, 2003 payment.

The Company declared dividends on common shares in the amount of $64.0 million ($0.50 per common share) during the year ended December 31, 2002, up from $48.5 million ($0.40 per common share) in 2001 (2000 - $ nil).

CAPITAL EXPENDITURES

| ($ millions) | 2002 | 2001(1) | 2000(1) |
|---|---|---|---|
| BUSINESS COMBINATIONS | $ 2,393.2 | $ - | $ 1,687.3 |
| EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT | | | |
| Net property acquisitions | $ 440.2 | $ 519.2 | $ 150.2 |
| Land acquisition and retention | 113.5 | 100.5 | 79.7 |
| Seismic evaluations | 63.4 | 94.6 | 40.5 |
| Well drilling, completion and equipping | 625.6 | 635.3 | 508.9 |
| Pipeline and production facilities | 292.2 | 395.0 | 335.7 |
| TOTAL NET RESERVE REPLACEMENT EXPENDITURES | 1,534.9 | 1,744.6 | 1,115.0 |
| Horizon Project | 68.1 | 26.8 | - |
| Midstream | 20.4 | 97.3 | - |
| Abandonments | 42.9 | 9.4 | 15.1 |
| Head office | 9.9 | 6.4 | 5.9 |
| TOTAL NET CAPITAL EXPENDITURES | $ 1,676.2 | $ 1,884.5 | $ 1,136.0 |
| BY SEGMENT (excluding business combinations) | | | |
| North America | $ 1,132.1 | $ 1,485.5 | $ 1,041.8 |
| North Sea | 333.3 | 97.8 | 54.9 |
| Offshore West Africa | 190.4 | 203.9 | 39.3 |
| Midstream | 20.4 | 97.3 | - |
| Total | $ 1,676.2 | $ 1,884.5 | $ 1,136.0 |

(1) Restated to conform to current year presentation.

The Company's strategy is focused on continuing to build a diversified asset base, that is balanced between products, namely natural gas, light oil, Pelican Lake oil, primary heavy oil and thermal heavy oil.

Capital expenditures totaled $1,676.2 million in the year 2002, excluding the acquisition of Rio Alto, compared to $1,884.5 million in 2001 (2000 - $1,136.0

million, excluding the acquisition of Ranger). Capital expenditures on North American properties accounted for 69% of total capital





expenditures (2001 - 84%, 2000 - 92%), with the remainder expended in the Company's core operating regions in the North Sea and Offshore West Africa. In 2002, the number of net wells drilled (excluding injection/stratigraphic test wells) decreased 39% to 453 from the 739 in 2001 (2000 - 775 net wells). The number of natural gas wells drilled was 162 net wells, down from 476 net wells in 2001 (2000 - 408 net wells), which reflects the Company's decision to defer natural gas drilling from 2002 to 2003 to offset anticipated Ladyfern production declines. In addition, during 2002 the Company drilled 293 net stratigraphic test wells on the oil sands leases in the Horizon Project. The first quarter of 2002 included natural gas exploration that concentrated on larger outlying pools in the Ladyfern area and the construction and commissioning of the Ladyfern natural gas pipeline.

North Sea capital expenditures in 2002 included the consolidation of interests in the Banff, Kyle, Ninian, Lyell, Murchison and Columba fields. The Company also acquired an interest in 12 licenses covering 20 exploration blocks and part blocks, and additional equity interests in the Brent and Ninian pipelines and the Sullom Voe Terminal. The consideration for these acquisitions included cash payments and the Company's interests in the Harding, Pierce and Claymore fields. As a result of these acquisitions, the Company was able to assume operatorship of several fields during 2002.

Offshore West Africa capital expenditures in Cote d'Ivoire included the continued development of the Espoir and Baobab fields. During 2002, three producing wells and two water injection wells were completed in the Espoir field. Unanticipated uphole faults delayed completion of the fourth producing well. Development continued on the Baobab field, where a second successful well was drilled and tested at a rate in excess of 10,000 bbls/d in the first quarter of 2002. The Company received approval for the Baobab development plan by the Government of Cote d'Ivoire in December 2002. During December 2002, a satellite pool, Emien, was drilled but encountered no hydrocarbons. The Company also acquired an interest in the exploration Block CI-400 in deeper waters offshore Cote d'Ivoire. This block is located adjacent to the Baobab discovery. The Company will operate Block CI-400 and retain a 90% working interest. In addition, during 2002 the Company entered into a production sharing agreement ("PSA") for Block 16, offshore Angola, in which the Company has a 50% working interest. The PSA was effective September 1, 2002 for an initial four-year period.

ENVIRONMENT

The Company's environmental management plan and operating guidelines focus on minimizing the impact of field operations while meeting regulatory requirements and corporate standards. The Company as part of this plan has implemented a proactive program than includes:

- An annual internal environmental compliance audit and inspection program of our operating facilities;

- An aggressive suspended well inspection program to support future development or eventual abandonment;

- Appropriate reclamation and decomissioning standards for wells and facilities ready for abandonment;
- An effective surface reclamation program;
- A progressive due diligence program related to groundwater monitoring;
- A rigorous program related to preventing and reclaiming spill sites; and
- A solution gas reduction and conservation program.

Internationally, the Company has established stringent operating standards in four areas:

- Using water-based, environmentally friendly drilling muds whenever possible;
- Implementing cost effective ways of reducing greenhouse natural gas emissions per unit of production;
- Exercising care with respect to all waste produced through effective waste management plans; and
- Minimizing produced water volumes onshore and offshore through cost-effective measures.

In 2002, the Company's capital expenditures included $42.9 million of abandonment expenditures, up from $9.4 million in 2001 (2000 - $15.1 million).

ESTIMATED FUTURE SITE RESTORATION LIABILITY
($ millions, excluding salvage value)

| | 2002 |
|---|---|
| North America | 1,206.0 |
| North Sea | 745.3 |
| Offshore West Africa | 34.9 |
| | 1,986.2 |
| North Sea PRT recovery | (304.9) |
| | 1,681.3 |

The estimate of the future site restoration liability is based on estimates of future costs to abandon and restore the wells, production facilities and offshore production platforms. There are numerous factors that affect these costs including such things as the number of wells drilled, well depth and the specific environmental legislation. The estimated costs are based on engineering estimates using current costs and technology in accordance with current legislation and industry practice. It is important to note that the future abandonment costs to be incurred by the Company in the North Sea

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will result in an estimated recovery of PRT of $304.9 million, as abandonment costs are an allowable deduction in determining PRT and may be carried back to reclaim PRT previously paid. The PRT recovery reduces the net abandonment liability of the Company to $1,681.3 million.

The Company's strategy in the North Sea consists of developing commercial hubs around its core operated properties with the goal of increasing production, lowering costs and extending the economic lives of its production facilities, thereby delaying the eventual abandonment dates.

RISKS AND UNCERTAINTIES

The Company is exposed to several operational risks inherent in exploring, developing, producing and marketing of oil and natural gas. These inherent risks include: economic risk of finding and producing reserves at a reasonable cost; financial risk of marketing reserves at an acceptable price given current market conditions; cost of capital risk associated with securing the needed capital to carry out the Company's operations; risk of fluctuating foreign exchange rates; risk of carrying out operations with minimal environmental impact; risk of governmental policies, social instability or other political, economic or diplomatic developments in its international operations; and credit risk of non-payment for sales contracts or non-performance by counterparties to contracts.

The Company uses a variety of means to help minimize these risks. The Company maintains a comprehensive insurance program to reduce risk to an acceptable level and to protect it against potentially significant losses. Operational control is enhanced by focusing efforts on large core regions with high working interests and by assuming operatorship of all key facilities. Product mix is diversified, ranging from the production of natural gas to the production of oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Sales of oil and natural gas are aimed at various markets to ensure that undue exposure to any one market does not exist. Financial instruments are utilized to help ensure targets are met and to manage commodity prices, foreign currency rates and interest rate exposure. The Company minimizes credit risks by entering into sales contracts and financial derivatives with only highly rated entities and financial institutions. In addition, the Company reviews its exposure to individual companies on a regular basis, and where appropriate ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default.

The Company's current position with respect to its financial instruments is detailed in note 12 of the Company's consolidated financial statements. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions.

The Company's capital structure mix is also monitored on a continual basis to ensure that it optimizes flexibility, minimizes cost, and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk that may exist.

The Company continues to employ an Environmental Management Plan (the "Plan") to ensure the welfare of its employees, the communities in which it operates, and the environment as a whole. Environmental protection is of fundamental importance and is undertaken in accordance with guiding principles approved by the Company's Board of Directors. A detailed copy of the Company's Plan is presented to, and reviewed by, the Board of Directors annually. The Plan is updated quarterly at the Directors' meetings.

KYOTO PROTOCOL

The Horizon Project is situated on leases containing over 6 billion bbls of mineable oil reserves, supporting a three-phase development that will produce 232,000 bbls/d of light, sweet oil for over 40 years. The Horizon Project encompasses four operational segments: minesite, extraction, primary upgrading and secondary upgrading. Additional development potential also exists on the leases to extract a further 2 billion bbls of mineable reserves and 1 billion bbls of in-situ reserves. To date, capital expenditures of $228.7 million have been incurred on the Horizon Project.

The Company believes that certainty of long-term costs and implementation consistency is required prior to the final commitment for an investment as large as the Horizon Project. In December 2002, the Canadian Federal Government ratified the Kyoto Protocol ("Kyoto") which has resulted in a decrease in cost certainty. Recently, the Canadian Federal Government has provided some limits to the cost of Kyoto implementation through 2012; however, beyond 2012 no implementation certainty exists. As the Horizon Project is scheduled to commence production in 2008 and produce for over 40 years, the lack of clarity on Kyoto implementation over the long term precludes the Company's ability to commit to the construction of the Horizon Project at this time.

The Company anticipates completion of its Design Basis Memorandum ("DBM") phase of engineering in the first quarter of 2003. Although sufficient levels of implementation certainty to start construction do not exist today, the Company anticipates such levels of certainty will be achieved, and therefore has decided to continue with the Engineering Design Specification ("EDS") phase of engineering. The EDS will commence after completion of the DBM, with related 2003 expenditures included in the Company's current Horizon Project budget of $211 million.

The Company will continue to work with the Canadian Federal Government to clarify long-term economic consequences of Kyoto implementation on the Horizon Project before any site clearing or pre-construction work begins in 2004.

COTE D'IVOIRE

The Company's development activities in Cote d'Ivoire remain unaffected by recent political insurrection in the country as the Company's operations are located offshore. The Company has established back-up facilities in a neighbouring country to ensure operations are not affected should conditions significantly deteriorate. To date, the Company has not needed to utilize this contingency.



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CRITICAL ACCOUNTING ESTIMATES

A comprehensive discussion of the Company's significant accounting policies is contained in note 1 to the consolidated financial statements. The following is a discussion of the accounting estimates that are critical in determining the Company's financial results.

FULL COST ACCOUNTING

The Company follows the full cost method of accounting for oil and natural gas properties and equipment as prescribed by the Canadian Institute of Chartered

Accountants. Accordingly, all costs relating to the exploration for and development of oil and natural gas reserves are capitalized and accumulated in country-by-country cost centres. The capitalized costs related to each cost centre from which there is production are depleted on the unit-of-production method based on the estimated proved reserves of that country. Capitalized costs in each cost centre may not exceed the sum of discounted future net revenues from proved properties and the cost of unproved properties, net of provision for impairment, less estimated future financing and administrative expenses and income taxes (the "ceiling test"). If the net capitalized costs of a cost centre are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates, the excess must be charged as an expense against net earnings. Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of profit or loss except where such disposal constitutes a significant portion of the Company's reserves in that country.

The alternate acceptable method of accounting for oil and natural gas properties and equipment is the successful efforts method. A major difference in applying the successful efforts method is that exploratory dry holes and geological and geophysical exploration costs would be charged against net earnings in the year incurred rather than being capitalized to property, plant and equipment. In addition, under this method cost centres are defined based on reserve pools rather than by country.

OIL AND NATURAL GAS RESERVES

The Company retains independent petroleum engineering consultants Sproule Associates Limited ("Sproule") to evaluate the Company's proved and probable oil and natural gas reserves and prepares an evaluation report on the Company's total reserves. In 2002, Sproule's report incorporated 89% of the Company's reserves with the Company internally evaluating the remaining 11%.

The estimation of reserves involves the exercise of judgement. Forecasts are based on engineering data, future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Company expects that over time its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depreciation, depletion and amortization. A revision to the reserve estimate could result in a higher or lower DD&A charge to net earnings. Downward revisions to reserve estimates could also result in a write-down of oil and natural gas property, plant and equipment under the ceiling test.

FUTURE SITE RESTORATION

The Company provides for the estimated future dismantlement, site restoration and abandonment costs of oil and natural gas properties using the unit-of-production method. Processing and production facilities are provided for using the straight-line method over their estimated useful lives of 20 years. The annual provision is included in depletion, depreciation and amortization. The estimated costs are based on engineering estimates using current costs and technology in accordance with current legislation and industry practice. The estimation of these costs can be affected by factors such as the number of wells drilled, well depth and area specific environmental legislation. These estimates are reviewed regularly and could impact the DD&A rate used by the Company. A revision to these estimated future costs could result in a higher or lower DD&A expense charged to net earnings.

STOCK-BASED COMPENSATION

The Company's Stock Option Plan (the "Option Plan") provides for granting of stock options to directors, officers and employees. Stock options granted under the Option Plan have a maximum term of six years to expiry and vest equally over a five-year period starting on the first anniversary date of the grant. The exercise price of each stock option granted is determined as the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the day of the grant. Each stock option granted permits the holder to purchase one common share of the Company at the stated exercise price. Currently, GAAP does not require the Company to record compensation expense in the consolidated financial statements for stock options granted. If the Company had used the fair-value method to account for its stock based compensation, compensation expense of $24.9 million would have been charged to net earnings in 2002. Further details regarding the Company's stock-based compensation are included in note 9 of the consolidated financial statements.

OUTLOOK

The Company continues its strategy of maintaining a large portfolio of varied projects, which enables the Company over an extended period of time to provide consistent growth in production and high shareholder returns. Annual budgets are developed, scrutinized throughout the year and changed if necessary in the context of project returns, product pricing expectations, and balance in project risk and time horizons. The Company maintains a high ownership level and operatorship level in all of its properties and can therefore control the nature, timing and extent of capital expenditures in each of its project areas.





The Company expects production levels in 2003 to average 1,280 to 1,330 mmcf/d of natural gas and 240 to 260 mbbls/d of oil and liquids, unchanged from previous expectations. First quarter 2003 production guidance for natural gas is 1,300 to 1,320 mmcf/d of natural gas and 235 to 240 mbbls/d of oil and liquids.

The budgeted capital expenditures for 2003 are as follows:

| | | |
|---|---|---|
| Canadian natural gas properties | $ | 691 million |
| Canadian oil properties | $ | 517 million |
| Horizon Project | $ | 211 million |
| International oil properties - North Sea | $ | 281 million |
| International oil properties - Offshore West Africa | $ | 280 million |
| Property acquisitions | $ | 300 million |
| Total capital expenditures | $ | 2,280 million |

In North America, the Company will commence development of the undeveloped land acquired in the Rio Alto acquisition with the drilling of 51 wells, 49 of which will be natural gas wells. Approximately 17 of the wells will be Cardium wells, which is a complex geological zone requiring both horizontal and vertical wells to test the production capabilities of the formation. The drilling in 2003 will be utilized to test and develop new geological theories on best practices for exploitation of the Cardium zone, thereby facilitating an expanded 2004 drilling program. In addition, an observation well will be drilled in the experimental Pelican Lake emulsion flood project in the first quarter of 2003 to assess the effectiveness of the injection to date. The Company will also be implementing a demonstration scale waterflood project to evaluate this secondary recovery technique, which should increase response time. If either project is successful, the recovery factor from the Pelican Lake sands is expected to increase. This field contains approximately three billion barrels of original oil-in-place but is only expected to achieve a 6% recovery factor using primary technologies.

Following regulatory approval in 2002 to utilize high-pressure steaming at its thermal oil project at Primrose in eastern Alberta, the Company will develop and drill new pads containing a total of 48 wells incorporating high-pressure steaming in 2003. Steaming of these wells will commence in the third quarter of 2003 with initial oil production following in mid 2004.

The Company anticipates receiving regulatory approvals for the Horizon Project from the Energy and Utilities Board in late 2003. The Company would be in a position to commence site clearing and pre-construction in 2004, with full construction commencing upon achieving a targeted 80% completion of detailed engineering and design. The first phase of the Horizon Project would then be commissioned in 2008 at 110,000 bbls/d of light synthetic oil. Phase two would be commissioned in 2010, increasing production to 155,000 bbls/d of production. Phase three would be completed in 2012, bringing total production to 232,000 bbls/d. The Company's leases could support further expansions beyond that date.

In 2003, the Company has budgeted to spend a total of $281 million on its international holdings in the North Sea. These funds will be directed towards drilling 18 wells in the North Sea. Other exploitation and waterflood optimization programs will also be carried out in both the northern and central areas of the North Sea to increase the productivity and recovery factors in these known pools of light oil.

Offshore West Africa budgeted capital expenditures total $280 million in 2003. In Cote d'Ivoire, the Company will complete the drilling and completion operations at Espoir, drill an exploration well at Acajou, and finalize the Baobab development plans with development drilling commencing in the fourth quarter of 2003. The Company also plans on drilling one of two identified prospects on its Block 16 exploration acreage, located offshore Angola, during the second half of 2003. This high-risk/high-potential exploration block, in which the Company is the operator with a 50% interest, is located in one of the world's most prolific oil basins.

The original budget was based on an average natural gas price of $5.20 per mcf at AECO, an oil price of US $24.00 per bbl for WTI and a heavy oil differential of US $8.50 per bbl. The current price-deck for our products, if maintained, could result in a significant increase in cash flow over the original budget established late in 2002. The Company will monitor its expected cash flow excess and at present intends to allocate a minimum of 50% of such excess towards debt repayment. The remaining excess will be directed to the Company's authorized share buy-back program and additional expenditures on conventional oil and natural gas opportunities. Such expenditures will only be incurred as excess cash flows are realized and will be subject to the same economic tests as regular budgeted expenditures. It is expected that the largest portion of the additional capital expenditures will take place late in the third and fourth quarters of 2003 and accordingly will not add materially to the Company's 2003 average production volumes. Should additional economic opportunities for share buy-backs or capital activities not present themselves to the extent allocated, such allocations of excess cash flow would revert to debt repayment.

SENSITIVITY ANALYSIS (1)

| | CASH FLOW FROM OPERATIONS(2) ($ millions) | CASH FLOW FROM OPERATIONS(2) ($/share, basic) | NET E ($ mi |
|---|---|---|---|
| PRICE CHANGES | | | |
| Oil - WTI US $1.00/bbl(3) | | | |
| Excluding financial derivatives | $104 | $0.78 | |
| Including financial derivatives | $69-$73 | $0.51-$0.55 | |
| Natural gas - AECO Cdn $0.10/mcf(3) | | | |
| Excluding financial derivatives | $38 | $0.28 | |
| Including financial derivatives | $38 | $0.28 | |
| Volume changes | | | |
| Oil - 10,000 bbls/d | $55 | $0.41 | |
| Natural gas - 10 mmcf/d | $12 | $0.09 | |
| Foreign currency rate change | | | |
| $0.01 change in Cdn $ in relation to US $(3) | | | |
| Excluding financial derivatives | $57 | $0.43 | |
| Including financial derivatives | $52-$55 | $0.39-$0.41 | |
| Interest rate change - 1% | $24 | $0.18 | |

(1) The sensitivities are calculated based on 2002 fourth quarter results.
(2) Attributable to common shareholders.
(3) For details of financial instruments in place, see consolidated financial statements note 12.

DAILY PRODUCTION BY SEGMENT

| | Q1 | Q2 | Q3 | Q4 | 2002 |
|---|---|---|---|---|---|
| OIL AND LIQUIDS (bbls/d) | | | | | |
| North America | 152,268 | 158,196 | 185,990 | 181,744 | 169,675 |
| North Sea | 30,910 | 25,685 | 47,114 | 51,478 | 38,876 |
| Offshore West Africa | 5,261 | 5,505 | 8,947 | 7,374 | 6,784 |
| Total | 188,439 | 189,386 | 242,051 | 240,596 | 215,335 |
| NATURAL GAS (mmcf/d) | | | | | |
| North America | 1,026 | 1,058 | 1,395 | 1,331 | 1,204 |
| North Sea | 27 | 20 | 29 | 32 | 27 |
| Offshore West Africa | - | - | 3 | 2 | 1 |
| Total | 1,053 | 1,078 | 1,427 | 1,365 | 1,232 |
| BARRELS OF OIL EQUIVALENT (boe/d) | | | | | |
| North America | 323,340 | 334,497 | 418,600 | 403,499 | 370,337 |
| North Sea | 35,389 | 29,020 | 51,946 | 56,879 | 43,391 |
| Offshore West Africa | 5,261 | 5,505 | 9,403 | 7,754 | 6,994 |

| | | | | | |
|---|---|---|---|---|---|
| Total | 363,990 | 369,022 | 479,949 | 468,132 | 420,722 |

PER UNIT RESULTS

| | Q1 | Q2 | Q3 | Q4 | 2002 |
|---|---|---|---|---|---|
| OIL AND LIQUIDS ($/bbl) | | | | | |
| Sales price | $ 24.50 | $ 28.27 | $ 33.57 | $ 31.10 | $ 29.76 |
| Royalties | 2.28 | 3.02 | 3.56 | 3.53 | 3.16 |
| Production expense | 7.81 | 7.95 | 8.67 | 9.10 | 8.45 |
| Netback | $ 14.41 | $ 17.30 | $ 21.34 | $ 18.47 | $ 18.15 |
| NATURAL GAS ($/mcf) | | | | | |
| Sales price | $ 3.06 | $ 3.68 | $ 3.13 | $ 5.00 | $ 3.76 |
| Royalties | 0.55 | 0.77 | 0.67 | 1.09 | 0.78 |
| Production expense | 0.58 | 0.57 | 0.55 | 0.57 | 0.57 |
| Netback | $ 1.93 | $ 2.34 | $ 1.91 | $ 3.34 | $ 2.41 |
| BARRELS OF OIL EQUIVALENT ($/boe) | | | | | |
| Sales price | $ 21.58 | $ 25.29 | $ 26.26 | $ 30.54 | $ 26.25 |
| Royalties | 2.78 | 3.79 | 3.80 | 4.98 | 3.91 |
| Production expense | 5.73 | 5.76 | 6.01 | 6.34 | 5.99 |
| Netback | $ 13.07 | $ 15.74 | $ 16.45 | $ 19.22 | $ 16.35 |

(1) Restated to conform to current year presentation.





NETBACK ANALYSIS

| ($/boe, except daily production) | 2002 | 2001(1) | 2000(1) |
|---|---|---|---|
| Daily production (boe/d) | 420,722 | 359,347 | 305,987 |
| Sales price | $ 26.25 | $ 27.15 | $ 28.77 |
| Royalties | 3.91 | 4.42 | 4.51 |
| Production expense | 5.99 | 5.69 | 5.02 |
| Netback | 16.35 | 17.04 | 19.24 |
| Midstream contribution | (0.25) | (0.12) | (0.26) |

| | | | |
|---|---|---|---|
| Administration | 0.40 | 0.29 | 0.25 |
| Interest | 1.03 | 1.05 | 1.45 |
| Realized foreign exchange loss (gain) | 0.02 | (0.01) | - |
| Taxes other than income tax (current) | 0.35 | 0.53 | 0.51 |
| Current income tax (North Sea) | (0.13) | 0.47 | 0.30 |
| Current income tax (Offshore West Africa) | 0.04 | - | - |
| Current income tax (Large Corporations Tax) | 0.14 | 0.11 | 0.13 |
| Cash flow | $ 14.75 | $ 14.72 | $ 16.86 |

(1) Restated to conform to current year presentation.

QUARTERLY FINANCIAL INFORMATION

| ($ millions, except per share amounts) | Q1 | Q2 | Q3 |
|---|---|---|---|
| 2002 | | | |
| Revenue | $ 717.5 | $ 862.8 | $ 1,172.6 |
| Cash flow from operations attributable to common shareholders | $ 359.1 | $ 474.5 | $ 643.8 |
| Per share - basic | $ 2.95 | $ 3.86 | $ 4.83 |
| - diluted | $ 2.85 | $ 3.70 | $ 4.71 |
| Net earnings attributable to common shareholders | $ 98.9 | $ 145.2 | $ 117.4 |
| Per share - basic | $ 0.81 | $ 1.18 | $ 0.88 |
| - diluted | $ 0.79 | $ 1.09 | $ 0.86 |
| 2001 | | | |
| Revenue | $ 1,130.7 | $ 981.2 | $ 810.5 |
| Cash flow from operations attributable to common shareholders | $ 629.3 | $ 527.6 | $ 437.4 |
| Per share - basic | $ 5.15 | $ 4.36 | $ 3.62 |
| - diluted | $ 5.03 | $ 4.17 | $ 3.54 |
| Net earnings attributable to common shareholders | $ 221.8 | $ 286.6 | $ 81.3 |
| Per share - basic | $ 1.82 | $ 2.37 | $ 0.67 |
| - diluted | $ 1.77 | $ 2.23 | $ 0.66 |

TRADING AND SHARE STATISTICS

| | Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|
| TSX - CDN $ | | | | |
| Trading volume (thousands) | 35,401 | 40,769 | 34,404 | 44,255 |
| Share price ($/share) | | | | |
| High | $ 53.05 | $ 54.54 | $ 53.91 | $ 50.50 |
| Low | $ 37.60 | $ 46.60 | $ 44.10 | $ 38.80 |
| Close | $ 51.60 | $ 51.52 | $ 50.35 | $ 46.80 |
| Market capitalization at December 31 ($ millions) | | | | |
| Shares outstanding (thousands) | | | | |
| NYSE - US $ | | | | |
| Trading volume (thousands) | 1,400 | 1,923 | 1,365 | 3,278 |
| Share price ($/share) | | | | |
| High | $ 33.25 | $ 34.48 | $ 34.88 | $ 31.81 |
| Low | $ 23.55 | $ 29.52 | $ 27.52 | $ 24.55 |

| | | | | |
|---|---|---|---|---|
| Close | $ 32.94 | $ 34.25 | $ 31.80 | $ 29.67 |
| Market capitalization at December 31 ($ millions) | | | | |
| Shares outstanding (thousands) | | | | |



DOCUMENT 3

# MANAGEMENT'S REPORT AND AUDITOR'S REPORT

## MANAGEMENT'S REPORT

The accompanying consolidated financial statements and all information in the annual report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies in the notes to the consolidated financial statements. Where necessary, management has made informed judgements and estimates in accounting for transactions which were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared within acceptable limits of materiality and are in accordance with Canadian generally accepted accounting principles appropriate in the circumstances. The financial information elsewhere in the annual report has been reviewed to ensure consistency with that in the consolidated financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized, assets are safeguarded from loss or unauthorized use and financial records are properly maintained to provide reliable information for preparation of financial statements.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent Annual General Meeting, to examine the consolidated financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion. Their report is presented with the consolidated financial statements.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee of the Board. This committee, which is comprised of non-management directors, meets with management and the external auditors to satisfy itself that management responsibilities are properly discharged and to review the consolidated financial statements before they are presented to the Board of Directors for approval. The consolidated financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

| | | |
|---|---|---|
| /s/ John G. Langille | /s/ Douglas A. Proll | /s/ Randall S. Davis |
| John G. Langille, CA | Douglas A. Proll, CA | Randall S. Davis, CA |
| President and Director | Senior Vice-president, Finance | Financial Controller |

February 26, 2003

AUDITORS' REPORT

To the Shareholders of Canadian Natural Resources Limited

We have audited the consolidated balance sheets of Canadian Natural Resources Limited as at December 31, 2002 and 2001 and the consolidated statements of earnings, retained earnings and cash flows for each of the years in the three year period ended December 31, 2002. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and 2001 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2002 in accordance with Canadian generally accepted accounting principles.

/s/ PriceWatershouseCooper LLP  
Chartered Accountants

Calgary, Alberta, Canada  
February 26, 2003

Comments by Auditor for US readers on Canada-US Reporting Differences

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Company's financial statements, such as the change described in note 2 to the consolidated financial statements. Our report to the shareholders dated February 26, 2003 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the Auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

/s/ PriceWatershouseCooper LLP  
Chartered Accountants

Calgary, Alberta, Canada  
February 26, 2003



## CONSOLIDATED FINANCIAL STATEMENTS

### CONSOLIDATED BALANCE SHEETS

As at December 31

| (millions of Canadian dollars) | 2002 | 2001 |
|---|---|---|

| | | |
|---|---|---|
| ASSETS | | |
| Current assets | | |
| Cash | $ 30.0 | $ 15.0 |
| Accounts receivable and other | 745.2 | 509.0 |
| | 775.2 | 524.0 |
| Property, plant and equipment (note 4) | 12,499.6 | 8,442.9 |
| Deferred charges | 84.1 | - |
| | 13,358.9 | 8,966.9 |
| LIABILITIES | | |
| Current liabilities | | |
| Accounts payable | 336.5 | 249.5 |
| Accrued liabilities | 428.4 | 264.2 |
| Current portion of long-term debt (note 5) | 24.1 | 15.9 |
| | 789.0 | 529.6 |
| Long term debt (note 5) | 4,074.0 | 2,669.2 |
| Future site restoration (note 6) | 440.4 | 193.8 |
| Future income tax (note 7) | 3,187.4 | 1,767.3 |
| | 8,490.8 | 5,159.9 |
| SHAREHOLDER'S EQUITY | | |
| Preferred securities (note 8) | 126.4 | 127.4 |
| Share capital (note 9) | 2,303.8 | 1,698.3 |
| Retained earnings | 2,414.3 | 1,908.5 |
| Foreign currency translation adjustment (note 10) | 23.6 | 72.8 |
| | 4,868.1 | 3,807.0 |
| | $ 13,358.9 | $ 8,966.9 |

Commitments (note 13) on behalf of the Board:

/s/ Gordon D. Giffin

Ambassador Gordon D. Giffin
Chairman of the Audit Committee
and Director

/s/ N. Murray Edwards

N. Murray Edwards
Vice-Chairman of the
Corporation and Director





CONSOLIDATED FINANCIAL STATEMENTS

| For the Years Ended December 31 (millions of Canadian dollars, except per common share amounts) | 2002 | 2001 |
|---|---|---|

| | | | | |
|---|---|---|---|---|
| REVENUE | $ | 4,083.2 | $ | 3,588.8 | $ |
| Less: royalties | | (600.3) | | (580.3) |
| | | 3,482.9 | | 3,008.5 |
| EXPENSES | | | | |
| Production | | 933.9 | | 757.9 |
| Depletion, depreciation and amortization | | 1,314.2 | | 903.8 |
| Administration | | 61.3 | | 37.6 |
| Interest | | 158.9 | | 137.8 |
| Foreign exchange (gain) loss (note 2) | | (31.7) | | 62.8 |
| Loss on sale of United States assets (note 4) | | - | | 24.1 |
| | | 2,436.6 | | 1,924.0 |
| EARNINGS BEFORE TAXES | | 1,046.3 | | 1,084.5 |
| Taxes other than income tax (note 7) | | 62.9 | | 69.1 |
| Current income tax (note 7) | | 7.6 | | 76.9 |
| Future income tax (note 7) | | 401.0 | | 282.5 |
| NET EARNINGS | | 574.8 | | 656.0 |
| Dividend on preferred securities, net of tax | | (6.0) | | (5.9) |
| Revaluation of preferred securities (note 2) | | 1.0 | | (7.5) |
| Net earnings attributable to common shareholders | $ | 569.8 | $ | 642.6 | $ |
| Net earnings attributable to common shareholders per common share (note 11) | | | | |
| Basic | $ | 4.46 | $ | 5.30 | $ |
| Diluted | $ | 4.31 | $ | 5.17 | $ |

CONOLIDATED STATEMENTS OF RETAINED EARNINGS

| For the Years Ended December 31 (millions of Canadian dollars) | | 2002 | | 2001 | |
|---|---|---|---|---|---|
| Balance - beginning of year as previously reported | $ | 1,979.5 | $ | 1,406.0 | $ |
| Change in accounting policy - foreign exchange (note 2) | | (71.0) | | (15.4) | |
| Balance - beginning of year as restated | | 1,908.5 | | 1,390.6 | |
| Net earnings | | 574.8 | | 656.0 | |
| Dividend on preferred securities, net of tax | | (6.0) | | (5.9) | |
| Revaluation of preferred securities (note 2) | | 1.0 | | (7.5) | |
| Dividend on common shares (note 9) | | (64.0) | | (48.5) | |
| Purchase of common shares (note 9) | | - | | (76.2) | |
| Balance - end of year | $ | 2,414.3 | $ | 1,908.5 | $ |

## CONSOLIDATED FINANCIAL STATEMENTS

| For the Years Ended December 31<br>(millions of Canadian dollars) | 2002 | 2001 | 2 |
|---|---|---|---|
| **OPERATING ACTIVITIES** | | | |
| Net earnings | $ 574.8 | $ 656.0 | $ |
| Non-cash items | | | |
| Depletion, depreciation and amortization | 1,314.2 | 903.8 | |
| Unrealized foreign exchange (gain) loss | (35.1) | 64.1 | |
| Deferred petroleum revenue tax | 9.5 | (0.2) | |
| Future income tax | 401.0 | 282.5 | |
| Loss on sale of United States assets | - | 24.1 | |
| Cash flow provided from operations | 2,264.4 | 1,930.3 | 1, |
| Deferred charges | (84.1) | - | |
| Net change in non-cash working capital | (156.9) | (42.2) | |
| | 2,023.4 | 1,888.1 | 1, |
| **FINANCING ACTIVITIES** | | | |
| Repayment of bank credit facilities | (1,234.3) | (442.3) | ( |
| Issue of medium-term notes | - | - | |
| Repayment of senior unsecured notes | (15.9) | (15.8) | |
| Issue of US dollar debt securities | 1,749.3 | 615.2 | |
| Repayment of obligations under capital leases | (3.9) | - | |
| Repayment of limited recourse loan | - | (11.8) | |
| Dividend on preferred securities | (10.4) | (10.3) | |
| Issue of common shares | 84.1 | 42.8 | |
| Dividend on common shares | (59.4) | (36.4) | |
| Purchase of common shares | - | (113.3) | |
| Net change in non-cash working capital | 26.0 | 7.4 | |
| | 535.5 | 35.5 | |
| **INVESTING ACTIVITIES** | | | |
| Business combinations, net of cash acquired (note 3) | (843.2) | - | ( |
| Expenditures on property, plant and equipment | (1,752.3) | (1,947.5) | (1, |
| Net proceeds on sale of property, plant and equipment | 76.1 | 63.0 | |
| Net expenditures on property, plant and equipment | (2,519.4) | (1,884.5) | (1, |
| Net change in non-cash working capital | (24.5) | (52.1) | |
| | (2,543.9) | (1,936.6) | (1, |
| Increase (decrease) in cash | 15.0 | (13.0) | |
| Cash - beginning of year | 15.0 | 28.0 | |

| | | | |
|---|---|---|---|
| Cash - end of year | $ 30.0 | $ 15.0 | $ |

Supplemental disclosure of cash flow information (note 14)



NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(tabular amounts in million of Canadian dollars, unless otherwise noted)

## 1. ACCOUNTING POLICIES

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

Within western Canada, the Company is developing its Horizon Oil Sands Project (the "Horizon Project") and maintains its midstream activities. The Horizon Project involves a plan to recover bitumen through mining operations, while the midstream activities include the Company's pipeline operations and an electricity co-generation system.

The consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in Canada. A summary of differences between accounting principles in Canada and those generally accepted in the United States ("US") is contained in note 16.

Significant accounting policies are summarized as follows:

### PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and all of its subsidiaries and partnerships. Portions of the Company's activities are conducted jointly with others and the consolidated financial statements reflect only the Company's proportionate interest in such activities.

### MEASUREMENT UNCERTAINTY

Management has made estimates and assumptions regarding certain assets, liabilities, revenues and expenses in the preparation of the consolidated financial statements. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts.

Depletion, depreciation and amortization and amounts used for ceiling test calculations are based on estimates of proved oil and natural gas reserves and future sales prices, production expenses and capital costs required to develop and produce those reserves. The majority of the Company's reserve estimates are evaluated annually by independent engineering firms. By their nature, estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact of differences between actual and estimated amounts on the consolidated financial statements of future periods could be material.

The measurement of petroleum revenue tax expense and the related provision in the consolidated financial statements are subject to uncertainty associated with future recoverability of oil and natural gas reserves, commodity prices and the timing of future events, which could result in material changes to deferred amounts.

CASH
Cash comprises cash on hand and demand deposits. Other investments (term deposits and certificates of deposit) with a term to maturity of three months or less from the transaction date are reported as cash equivalents.

PROPERTY, PLANT AND EQUIPMENT
The Company follows the full cost method of accounting for oil and natural gas properties and equipment as prescribed by the Canadian Institute of Chartered Accountants ("CICA"). Accordingly, all costs relating to the exploration for and development of oil and natural gas reserves are capitalized and accumulated in country-by-country cost centres. Administrative overhead incurred during the development phase of large capital projects is capitalized until commercial production commences. Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of profit or loss except where such disposal constitutes a significant portion of the Company's reserves in that country.

DEPLETION, DEPRECIATION AND AMORTIZATION
The costs related to each cost centre from which there is production are depleted on the unit-of-production method based on the estimated proved reserves of that country. Volumes of net production and net reserves before royalties are converted to equivalent units on the basis of estimated relative energy content. In determining its depletion base, the Company includes estimated future costs to be incurred in developing proved reserves and excludes the cost of unproved properties. The unproved properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the value of the unproved property is considered to be impaired, the cost of the unproved property or the amount of the impairment is added to costs subject to depletion. Certain costs in cost centres from which there has been no commercial production are not subject to depletion until commercial production commences.

Processing and production facilities, net of salvage value, are depreciated on a straight-line basis over their estimated useful lives of 20 years.

The Company carries its oil and natural gas properties at the lower of net capitalized cost and net recoverable amount (the "ceiling test"). The net capitalized cost of each cost centre is calculated as the net book value of the related assets less the accumulated provisions for future income taxes and future site restoration. Net recoverable amount is limited to the sum of undiscounted future net revenues from proved properties and the cost of unproved properties net of provisions for impairment less estimated future financing and administrative expenses and income taxes. Future net revenues are based on sales prices and costs prevailing at year end.

The Company carries its midstream assets at the lower of net capitalized cost and net recoverable amount. Midstream assets, net of salvage value, are depreciated on a straight-line basis over their estimated useful lives of 20 years.





Other capital assets are amortized on a declining balance basis over their estimated useful lives of five years.

DEFERRED CHARGES

Deferred charges include deferred financing costs associated with the issuance of long-term debt and settlement costs of long-term natural gas contracts. Deferred charges are amortized over the original term of the related instrument.

FUTURE SITE RESTORATION
Estimated future dismantlement, site restoration and abandonment costs of oil and natural gas properties are provided for using the unit-of-production method. Processing and production facilities are provided for using the straight-line method over their estimated useful lives of 20 years. The estimated costs are based on engineering estimates using current costs and technology in accordance with current legislation and industry practice. The annual provision is included in depletion, depreciation and amortization. Expenditures incurred to dismantle the processing and production facilities and to abandon and restore well sites are charged against the related site restoration liability.

FOREIGN CURRENCY TRANSLATION
Foreign operations that are operationally and financially independent are translated using the current rate method. Under this method, assets and liabilities are translated to Canadian dollars from their functional currency using the exchange rate in effect at the consolidated balance sheet date. Revenues and expenses are translated to Canadian dollars at the monthly average exchange rates. Gains or losses on translation are included in the foreign currency translation adjustment in shareholders' equity in the consolidated balance sheets.

Foreign operations that are not considered to be self-sustaining are translated using the temporal method. For foreign currency balances and integrated subsidiaries, monetary assets and liabilities are translated to Canadian dollars at the exchange rate in effect at the consolidated balance sheet date and non-monetary assets and liabilities are translated at the rate of exchange in effect when the assets were acquired or obligations incurred. Revenues and expenses are translated to Canadian dollars at the monthly average exchange rates. Provisions for depletion, depreciation and amortization are translated at the same rate as the related items.

PETROLEUM REVENUE TAX
The Company accounts for future United Kingdom petroleum revenue tax ("PRT") by the life-of-the-field method. The total future liability or recovery of PRT is estimated using current sales prices and costs. The estimated future PRT is apportioned to accounting periods on the basis of total estimated future revenues. Changes in the estimated total future PRT are accounted for prospectively.

PRODUCTION SHARING CONTRACT
Production generated from the Espoir field, offshore Cote d'Ivoire, is shared by the terms of the Production Sharing Contract ("PSC") with the State Oil Company of Cote d'Ivoire ("Petroci"). Revenues are divided into cost recovery revenues and profit revenues. Cost recovery revenues allow the Company to recover the capital and operating costs carried by the Company on behalf of Petroci. These revenues are reported as sales revenues. Profit revenues are allocated to the Espoir joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Cote d'Ivoire Government. The Government's share of revenues, attributable to the Company's equity interest, is reported as either a royalty expense or a current tax expense in accordance with the PSC.

INCOME TAX
The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences in the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted on the

consolidated balance sheet date. The effect of a change in income tax rates on the future income tax assets and liabilities is recognized in net earnings in the period of the change.

REVENUE RECOGNITION
Revenues are recognized when products have been delivered or services have been performed.

STOCK-BASED COMPENSATION PLANS
The Company accounts for its stock-based compensation using the intrinsic value method; therefore, no stock-based compensation expense is recorded either on granting or exercise of stock options under the Company's Stock Option Plan (the "Option Plan"). Consideration paid by employees, officers or directors on the exercise of stock options under the Option Plan is recorded as share capital. The Company matches employee contributions to the Company's Stock Savings Plan and these cash payments are recorded as compensation expense.

FINANCIAL INSTRUMENTS
Financial instruments are utilized by the Company 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's policy is to formally document relationships between hedging instruments and hedged items, the risk management objective, and the strategy for undertaking various hedge transactions. The Company assesses whether the financial instruments entered into are highly effective as fair value and cash flow hedges, both at the inception of the hedge and over the term of the financial instrument.

The Company enters into commodity price contracts to hedge anticipated sales of oil and natural gas production in order to protect cash flow for capital expenditure programs. Gains or losses on these contracts are included in oil and natural gas revenue at the time of sale of the related product.

Foreign exchange translation gains and losses on foreign currency denominated financial instruments used to hedge anticipated US dollar denominated oil and natural gas sales are recognized in revenue at the time of sale of the related product.

The Company has assumed, through the Rio Alto acquisition, a foreign currency swap agreement that hedges a foreign currency denominated long-term debt instrument through an offsetting forward exchange contract. The foreign exchange translation gains and losses on the financial instrument are used to offset the respective translation gains and losses recognized on the long-term debt.

The Company enters into interest rate swap agreements to manage its fixed to floating interest rate mix on long-term debt. These swaps are designated as hedges of the underlying debt. The interest rate swap agreements require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. Gains or losses on these financial instruments are included in interest expense in the consolidated statement of earnings when realized. The related amount receivable from or payable to counterparties is included as an adjustment to accrued interest in the consolidated balance sheets.

Realized gains and losses on the termination of financial instruments that have been accounted for as hedges are deferred under non-current assets or liabilities on the consolidated balance sheets and recognized in net earnings in the period in which the underlying hedged transaction is recognized.
In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any realized or unrealized gain or loss on such derivative instrument is recognized in net earnings.

PER COMMON SHARE AMOUNTS
The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. This method assumes that proceeds received from the exercise of in-the-money stock options and other dilutive instruments are used to purchase common shares at the average market price during the year.

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

2. CHANGE IN ACCOUNTING POLICY
FOREIGN CURRENCY TRANSLATION
Effective January 1, 2002, the Company retroactively adopted the CICA's new accounting standard with respect to foreign currency translation. As a result of adopting this new standard, gains or losses on the translation of long-term debt denominated in US dollars are no longer deferred and amortized over the term of the debt. Translation gains or losses are either recognized in net earnings immediately, or in the foreign currency translation adjustment (note 10) for translation gains or losses on that portion of the US dollar denominated debt designated as a hedge of self-sustaining foreign operations. This new standard has been adopted retroactively and prior periods have been restated.

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

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Consolidated balance sheets | | | |
| Decrease deferred foreign exchange loss | $ - | $ (61.9) | $ (13.8 |
| (Decrease) increase preferred securities | $ (1.0) | $ 9.1 | $ 1.6 |
| Decrease in opening retained earnings | $ (71.0) | $ (15.4) | $ (0.3 |
| Consolidated statements of earnings | | | |
| Foreign exchange (gain) loss | $ (53.3) | $ 48.1 | $ 13.5 |
| Revaluation of preferred securities (gain) loss | $ (1.0) | $ 7.5 | $ 1.6 |
| Increase (decrease) net earnings attributable to common shareholders per common share | | | |
| - Basic | $ 0.42 | $ (0.46) | $ (0.13 |
| - Diluted | $ 0.40 | $ (0.38) | $ (0.11 |

3. BUSINESS COMBINATIONS
RIO ALTO EXPLORATION LTD.
In July 2002, the Company paid cash of $850.0 million and issued 10,008,218 common shares with an attributed value of $522.4 million to acquire all of the issued and outstanding common shares of Rio Alto Exploration Ltd. ("Rio Alto") by way of a plan of arrangement (the "Plan of Arrangement").

## NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Rio Alto was engaged in the exploration for and production of oil and natural gas in western Canada and through wholly owned subsidiaries, in South America. Under the Plan of Arrangement, the subsidiaries of Rio Alto that held its South American properties were sold to a new company, Rio Alto Resources International Inc. ("Rio Alto International"), and each shareholder of Rio Alto received one common share of Rio Alto International for each Rio Alto common share held.

The acquisition was accounted for based on the purchase method. Results of Rio Alto are consolidated with the results of the Company since the date of acquisition. The allocation of the purchase price to assets acquired and liabilities assumed based on their fair values is set out in the following table:

| | July 1, 2002 |
|---|---|
| Purchase price: | |
| Cash consideration | $ 850.0 |
| Share consideration | 522.4 |
| Cash acquired | (6.8) |
| Non-cash working capital deficit assumed | 91.3 |
| Long-term debt assumed | 936.3 |
| Total purchase price | $ 2,393.2 |
| Purchase price allocated as follows: | |
| Property, plant and equipment | $ 3,411.8 |
| Future site restoration | (43.5) |
| Future income tax | (975.1) |
| | $ 2,393.2 |

RANGER OIL LIMITED

In July 2000, the Company paid cash of $722.8 million and issued 7,602,068 common shares with an attributed value of $358.0 million to acquire all of the issued and outstanding common shares of Ranger Oil Limited ("Ranger"). Ranger was engaged in the exploration for and development of oil and natural gas in the North Sea, North America and Offshore West Africa.

The acquisition was accounted for based on the purchase method. Results of Ranger are consolidated with the results of the Company since the date of acquisition. The allocation of the purchase price to assets acquired and liabilities assumed based on their fair values is set out in the following table:

| | July 1, 2000 |
|---|---|
| Purchase price: | |
| Cash consideration | $ 722.8 |

| | |
|---|---|
| Share consideration | 358.0 |
| Non-cash working capital deficit assumed | 111.6 |
| Long-term debt assumed | 376.6 |
| Preferred securities assumed | 118.3 |
| Total purchase price | $ 1,687.3 |

Purchase price allocated as follows:

| | |
|---|---|
| Property, plant and equipment | $ 1,966.4 |
| Future site restoration | (129.3) |
| Future income tax | (149.8) |
| | $ 1,687.3 |

4. PROPERTY, PLANT AND EQUIPMENT

| | 2002 | | |
|---|---|---|---|
| | COST | ACCUMULATED DEPLETION AND DEPRECIATION | NET |
| Oil and natural gas | | | |
| North America | $ 13,863.3 | $ 3,611.3 | $ 10,252.0 |
| North Sea | 1,621.2 | 344.2 | 1,277.0 |
| Offshore West Africa | 611.9 | 93.6 | 518.3 |
| Horizon Project | 228.7 | - | 228.7 |
| Midstream | 214.0 | 18.4 | 195.6 |
| Other | 50.1 | 22.1 | 28.0 |
| | $ 16,589.2 | $ 4,089.6 | $ 12,499.6 |





PROPERTY, PLANT AND EQUIPMENT (continued)

| | 2001 | | |
|---|---|---|---|
| | Cost | Accumulated depletion and depreciation | Net |
| Oil and natural gas | | | |
| North America | $ 9,424.7 | $ 2,617.1 | $ 6,807.6 |
| North Sea | 1,050.3 | 184.7 | 865.6 |
| Offshore West Africa | 425.2 | 15.3 | 409.9 |
| Horizon Project | 160.6 | - | 160.6 |
| Midstream | 193.6 | 10.8 | 182.8 |
| Other | 32.3 | 15.9 | 16.4 |

| | | | |
|---|---|---|---|
| | $ 11,286.7 | $ 2,843.8 | $ 8,442.9 |

During the year ended December 31, 2002, the Company capitalized administrative overhead of $13.0 million (2001 - $6.7 million; 2000 - $3.7 million) relating to exploration and development in the North Sea and Offshore West Africa and $3.9 million (2001 - $nil, 2000 - $nil) relating to the Horizon Project in North America. During 2001, the Company sold a large portion of its properties in the United States and recorded a loss on sale of $24.1 million.

Included in property, plant and equipment are undeveloped land and projects under development that are not subject to depletion or depreciation:

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Oil and natural gas | | | |
| North America | $ 666.8 | $ 424.0 | $ 351.5 |
| North Sea | 62.0 | 49.5 | 45.5 |
| Offshore West Africa | 131.8 | 398.8 | 175.3 |
| Horizon Project | 228.7 | 160.6 | 141.8 |
| | $ 1,089.3 | $ 1,032.9 | $ 714.1 |

5. LONG-TERM DEBT

| | |
|---|---|
| Bank credit facilities | |
| Bankers' acceptances | $ |
| US $ Bankers' acceptances (2002 - US $150.0 million, 2001 - US $196.0 million) | |
| US $ LIBOR advances (2002 - US $nil, 2001 - US $100.0 million) | |
| Medium-term notes | |
| 6.85% unsecured debentures due May 28, 2004 | |
| 7.40% unsecured debentures due March 1, 2007 | |
| Senior unsecured notes | |
| 6.95% due September 30, 2003 (2002 - US $10.0 million, 2001 - US $20.0 million) | |
| 6.42% due May 27, 2004 (US $40.0 million) | |
| 7.69% due December 19, 2005 (US $125.0 million) | |
| 6.50% due May 1, 2008 (US $50.0 million) | |
| Adjustable rate due May 27, 2009 (US $93.0 million) | |
| US dollar debt securities | |
| 6.70% due July 15, 2011 (US $400.0 million) | |
| 5.45% due October 1, 2012 (US $350.0 million) | |
| 7.20% due January 15, 2032 (US $400.0 million) | |
| 6.45% due June 30, 2033 (US $350.0 million) | |
| Obligations under capital leases | |
| | 4 |
| Less: current portion of long-term debt | |
| | $ 4 |

## NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

BANK CREDIT FACILITIES

The Company has unsecured bank credit facilities of $2,275.0 million comprised of a $100.0 million operating demand facility, a revolving credit and term loan facility of $1,675.0 million and a $500.0 million acquisition term credit facility repayable July 3, 2004. The Canadian dollar revolving credit and term loan facility is fully revolving for 364-day periods with a provision for extension at the mutual agreement of the Company and the lenders. If not extended, the facility converts to a non-revolving reducing loan with a term of three years. Principal payments during the term period amortize on the basis of one-third of the outstanding principal being due 12 months after the initiation of the term period followed by eight equal quarterly payments thereafter. The facility provides that the borrowings may be made by way of operating advances, prime loans, bankers' acceptances, US base rate loans or US dollar LIBOR advances which bear interest at the bank's prime rates or at money market rates plus applicable margins. During the year, the Company repaid and cancelled a $725.0 million credit and term loan facility and a US $150.0 million credit and term loan facility.

The weighted average interest rate of bank credit facilities outstanding at December 31, 2002 was 3.37% (2001 - 2.71%). Included in this rate is debt under the bank credit facilities totaling $100.0 million that is subject to an interest rate swap that fixes the interest rate at 5.08% plus a stamping fee (note 12).

In addition to the outstanding debt, letters of credit aggregating to $25.1 million have been issued.

MEDIUM-TERM NOTES

In July 2001, the Company authorized a medium-term note program in the aggregate principal amount of up to $1.0 billion for issue in Canada until July 2003. If issued, these notes will bear interest as determined at the date of issuance. No amounts are currently drawn under this program. The Company has $250.0 million of unsecured debentures outstanding from a previous medium-term note program.

SENIOR UNSECURED NOTES

The final principal repayment on the 6.95% senior unsecured notes is due September 30, 2003. The 6.42% senior unsecured notes are due in full May 27, 2004. Annual principal repayments of US $10.0 million on the 6.50% notes commence May 1, 2004, and are payable through May 1, 2008. The adjustable rate senior unsecured notes bear interest at 6.54% increasing to 6.64% under certain circumstances, and have annual principal repayments of US $31.0 million commencing on May 27, 2007, through May 27, 2009. The debt instruments contain covenants pertaining to the Company's net worth, certain financial ratios and the ability to grant security.

On July 1, 2002, as part of the Rio Alto acquisition, the Company assumed US $125.0 million of senior unsecured notes maturing December 19, 2005, bearing interest at 7.69%. Through a currency swap, the interest and principal repayment amounts are fixed at 7.30% and $193.7 million, respectively (note 12).

US DOLLAR DEBT SECURITIES

On July 24, 2001, the Company issued US $400.0 million of US dollar debt securities, maturing July 15, 2011, bearing interest at 6.70%. Subsequently, the Company entered into interest rate swap contracts that convert the fixed rate interest coupon into a floating interest rate for a portion of the term (note 12).

On January 23, 2002, the Company issued US $400.0 million of US dollar debt securities, maturing January 15, 2032, bearing interest at 7.20%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. Subsequently, the Company entered into interest rate swap contracts that convert the fixed rate interest coupon into a floating interest rate for a portion of the term (note 12).

On September 16, 2002, the Company issued US $350.0 million of US dollar debt securities maturing October 1, 2012, bearing interest at 5.45% and US $350.0 million of US dollar debt securities maturing June 30, 2033, bearing interest at 6.45%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. Subsequently, the Company entered into interest rate swap contracts that convert the fixed rate interest coupon into a floating interest rate for a portion of the ten-year securities (note 12).

The Company has US $300.0 million remaining on a US $1.0 billion shelf prospectus filed on August 16, 2002 that allows for the issue of debt securities until September 2004. If issued, these securities will bear interest as determined at the date of issuance.

OBLIGATIONS UNDER CAPITAL LEASES

The obligations under capital leases bear interest at an average interest rate of 6.91% and are secured by the related assets.

REQUIRED DEBT REPAYMENTS

Required debt repayments are as follows:

| Year | Repayment |
|---|---|
| 2003 | $ 24.1 |
| 2004 | $ 710.8 |
| 2005 | $ 209.5 |
| 2006 | $ 15.8 |
| 2007 | $ 189.8 |
| Thereafter | $ 2,483.2 |





No debt repayments are reflected for the bank credit facilities due to the extendable nature of the facilities, other than the $500.0 million acquisition term credit facility due July 3, 2004.

6. FUTURE SITE RESTORATION

| | 2002 | 2001 |
|---|---|---|
| Balance - beginning of year | $ 193.8 | $ 170.5 |
| Future site restoration provision | 69.4 | 34.1 |

| | | |
|---|---|---|
| Current year expenditures | (34.3) | (9.4) |
| Acquisitions and dispositions | 211.5 | (1.4) |
| Balance - end of year | $ 440.4 | $ 193.8 |

At December 31, 2002, the Company's total estimated future site restoration costs, excluding salvage values, were $1,986.2 million (2001 - $1,081.0 million, 2000 - $874.3 million). These costs are accrued over the life of the Company's proved reserves.

7. TAXES

| Taxes other than income tax | 2002 | 2001 | 2000 |
|---|---|---|---|
| Current petroleum revenue tax | $ 41.6 | $ 59.3 | $ 40.9 |
| Deferred petroleum revenue tax | 9.5 | (0.2) | (7.6) |
| Provincial capital taxes and surcharges | 11.1 | 8.5 | 12.3 |
| Other | 0.7 | 1.5 | 3.9 |
| | $ 62.9 | $ 69.1 | $ 49.5 |

Income tax
The provision for income tax is as follows:

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Current income tax expense | | | |
| Current income tax - North Sea | $ (19.6) | $ 61.8 | $ 33.7 |
| Current income tax - Offshore West Africa | 6.0 | - | - |
| Large Corporations Tax - North America | 21.2 | 15.1 | 14.7 |
| | 7.6 | 76.9 | 48.4 |
| Future income tax expense | 401.0 | 282.5 | 464.0 |
| Income taxes | $ 408.6 | $ 359.4 | $ 512.4 |

The provision for income taxes is different from the amount computed by applying the combined statutory Canadian federal and provincial income tax rates to earnings before taxes. The reasons for the difference are as follows:

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Canadian statutory income tax rate | 42.4% | 42.8% | 44.0% |
| Income tax provision at statutory rate | $ 443.6 | $ 464.2 | $ 586.7 |
| Effect on income taxes of: | | | |
| Non-deductible crown royalties, lease rentals and mineral taxes | 211.0 | 201.1 | 193.2 |

| | | | |
|---|---|---|---|
| Resource allowance | (243.4) | (219.5) | (238.1) |
| Large Corporations Tax | 21.2 | 15.1 | 14.7 |
| Deductible petroleum revenue tax | (21.7) | (25.3) | (14.6) |
| Foreign income tax rate differentials | (1.4) | (18.9) | (40.9) |
| Provincial income tax rate reductions | (20.5) | (63.1) | - |
| UK income tax rate increase | 34.0 | - | - |
| Foreign exchange | (21.7) | 20.6 | 5.9 |
| Other | 7.5 | (14.8) | 5.5 |
| Income taxes | $ 408.6 | $ 359.4 | $ 512.4 |





The following table summarizes the temporary differences that give rise to the future income tax liability:

| | 2002 | 2001 |
|---|---|---|
| Future income tax liabilities | | |
| Property, plant and equipment | $ 2,656.0 | $ 1,384.8 |
| Timing of partnership items | 736.9 | 493.2 |
| Other | 27.5 | 5.0 |
| Future income tax assets | | |
| Future site restoration | (160.5) | (54.1) |
| Attributed Canadian Royalty Income | (54.0) | (39.8) |
| Other | (14.1) | (9.9) |
| Deferred petroleum revenue tax | (4.4) | (11.9) |
| Future income tax liability | $ 3,187.4 | $ 1,767.3 |

8. PREFERRED SECURITIES

The US $80.0 million preferred securities are in the form of 8.30% subordinated notes. Principal repayments of US $26.7 million are required annually commencing June 25, 2009. The securities may be prepaid at the option of the Company at any time. The prepaid amount is subject to certain adjustments to compensate holders for any potential loss of return over the original life of the securities, based on market conditions at that time. The notes are subordinated to the long-term debt of the Company and contain, among other things, certain financial covenants restricting the granting of security for new borrowings and the maintenance of specified financial ratios.

The Company has the unrestricted right to pay dividends, principal and principal prepayment amounts by delivering common shares to the Trustee of the preferred securities. Accordingly, the preferred securities are classified as shareholders' equity in the consolidated balance sheets. Dividend payments, net of tax, are charged directly to retained earnings. The semi-annual dividend payments may be deferred at the option of the Company for up to two consecutive periods, with a maximum of eight deferral periods over the life of the securities.

9. SHARE CAPITAL

AUTHORIZED

200,000 Class 1 preferred shares with a stated value of $10.00 each. Unlimited number of common shares without par value.

ISSUED

| | 2002 | | |
|---|---|---|---|
| COMMON SHARES | NUMBER OF SHARES (THOUSANDS) | AMOUNT | NUMBE (T |
| Balance - beginning of year | 121,201 | $ 1,698.3 | |
| Issued upon acquisition of Rio Alto | 10,008 | 522.4 | |
| Issued upon exercise of stock options | 2,523 | 82.1 | |
| Issue of flow-through shares, net of tax | 60 | 1.3 | |
| Cancellation of common shares | (16) | (0.3) | |
| Exercise of warrants | - | - | |
| Purchase of common shares under Normal Course Issuer Bid | - | - | |
| Balance - end of year | 133,776 | $ 2,303.8 | |

The Company issued 10,008,218 common shares at an attributed value of $522.4 million as part of the consideration to acquire Rio Alto (note 3).

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





During the the year, 16,288 common shares were returned to treasury and cancelled on the expiry of the conversion period for exchanging shares of companies previously acquired for common shares of the Company.

NORMAL COURSE ISSUER BID

In January 2003, the Company renewed its Normal Course Issuer Bid, allowing the Company to purchase up to 6,692,799 common shares or 5% of the Company's outstanding common shares on the date of announcement, during the 12-month period beginning January 24, 2003 and ending January 23, 2004. As at February 26, 2003, 175,600 common shares for a total cost of $8.3 million have been purchased under this renewed Normal Course Issuer Bid.

Under a previous Normal Course Issuer Bid, the Company purchased 2,537,800 common shares in 2001 for a total cost of $113.3 million. The excess cost over book value of the common shares purchased was applied to eliminate contributed surplus and reduce retained earnings.

DIVIDEND POLICY

The Company pays regular quarterly dividends in January, April, July and October of each year. In February 2003, the Board of Directors set the Company's regular quarterly dividend at $0.15 per common share (2002 - $0.125 per common share, 2001 - $0.10 per common share, 2000 - $nil per common share) commencing with the April 1, 2003 payment.

WARRANTS

During 1999, the Company issued 500,000 warrants at an ascribed value of $2.9 million to acquire property, plant and equipment. Each warrant entitled the holder to acquire one common share of the Company at a price of $30.00 per common share until August 16, 2001.

STOCK OPTIONS

The Company's Stock Option Plan (the "Option Plan") provides for the granting of stock options to directors, officers and employees. Stock options granted under the Option Plan have a maximum term of six years to expiry and vest equally over a five-year period starting on the first anniversary date of the grant. The exercise price of each stock option granted is determined as the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the day of the grant. Each stock option granted permits the holder to purchase one common share of the Company at the stated exercise price.

The following table summarizes information relating to stock options outstanding and exercisable under the Option Plan at December 31, 2002 and 2001:

| | 2002 | | 2001 | |
|---|---|---|---|---|
| | STOCK OPTIONS (thousands) | WEIGHTED AVERAGE EXERCISE PRICE | STOCK OPTIONS (thousands) | |
| Outstanding - beginning of year | 12,051 | $ 34.77 | 10,664 | $ |
| Granted | 3,845 | $ 41.88 | 3,500 | $ |
| Exercised | (2,523) | $ 32.54 | (1,005) | $ |
| Forfeited | (491) | $ 40.03 | (1,108) | $ |
| Outstanding - end of year | 12,882 | $ 37.13 | 12,051 | $ |
| Exercisable - end of year | 3,508 | $ 32.53 | 3,615 | $ |

The range of exercise prices of stock options outstanding and exercisable under the Option Plan at December 31, 2002 is as follows:

| | STOCK OPTIONS OUTSTANDING | | | STOCK OP |
|---|---|---|---|---|
| RANGE OF EXERCISE PRICES | STOCK OPTIONS OUTSTANDING (thousands) | WEIGHTED AVERAGE REMAINING TERM (years) | WEIGHTED AVERAGE EXERCISE PRICE | STOCK OPTIONS EXERCISABLE (thousands |
| $19.90 to $24.99 | 1,106 | 1.8 | $ 22.02 | 750 |
| $25.00 to $29.99 | 1,069 | 1.2 | $ 27.13 | 691 |

| | | | | |
|---|---|---|---|---|
| $30.00 to $34.99 | 2,555 | 2.8 | $ 33.63 | 927 |
| $35.00 to $39.99 | 4,556 | 4.4 | $ 39.03 | 578 |
| $40.00 to $44.99 | 1,868 | 4.3 | $ 43.19 | 446 |
| $45.00 to $48.50 | 1,728 | 5.2 | $ 46.61 | 116 |
| | 12,882 | 3.7 | $ 37.13 | 3,508 |

STOCK-BASED COMPENSATION COSTS
The Company accounts for its stock-based compensation using the intrinsic value method and as a result, no compensation costs have been recorded in the consolidated financial statements for stock options granted or exercised. Had the Company adopted the fair value based method of accounting,





the compensation costs, along with the pro forma net earnings attributable to common shareholders and pro forma net earnings attributable to common shareholders per common share of the Company would be as follows:

| | 2002 | 2 |
|---|---|---|
| Stock-based compensation costs | $ 24.9 | $ 1 |
| Net earnings attributable to common shareholders | | |
| As reported | $ 569.8 | $ 64 |
| Pro forma | $ 544.9 | $ 62 |
| Net earnings attributable to common shareholders per common share | | |
| Basic | | |
| As reported | $ 4.46 | $ 5 |
| Pro forma | $ 4.26 | $ 5 |
| Diluted | | |
| As reported | $ 4.31 | $ 5 |
| Pro forma | $ 4.12 | $ 5 |

The stock-based compensation costs are recognized over the vesting period of the stock options granted. The pro forma amounts shown above do not include the stock-based compensation costs associated with stock options granted prior to January 1, 2000.

The fair value of each stock option granted is estimated on the date of grant using the Black-Scholes option pricing model based on the following:

| | 2002 |
|---|---|
| Fair value of stock options granted (per common share) | |

| | | |
|---|---|---|
| Directors, officers and executives | $ 14.70 | $ 1 |
| Other employees | $ 12.29 | $ 1 |
| Risk-free interest rate | 3.7% | |
| Expected life (years) | | |
| Directors, officers and executives | 5.5 | |
| Other employees | 3.7 | |
| Expected volatility | 35% | |
| Expected dividend yield | 1.2% | |

10. FOREIGN CURRENCY TRANSLATION ADJUSTMENT

The foreign currency translation adjustment represents the unrealized gain (loss) on the Company's net investment in self-sustaining foreign operations. Effective July 1, 2002, the Company designated certain US dollar denominated debt as a hedge against its net investment in US dollar-based self-sustaining foreign operations. Accordingly, gains and losses on this debt are included in the foreign currency translation adjustment.

| | 2002 | 2001 |
|---|---|---|
| Balance - beginning of year | $ 72.8 | $ - |
| Unrealized (loss) gain on translation of net investment | (11.6) | 72.8 |
| Hedge of net investment with US dollar denominated debt | (37.6) | - |
| Balance - end of year | $ 23.6 | $ 72.8 |





NET EARNINGS AND CASH FLOW FROM OPERATIONS PER COMMON SHARE

The following table provides a reconciliation between basic and diluted amounts per common share:

| (thousands) | 2002 |
|---|---|
| Weighted average common shares outstanding - basic | 127,883 |
| Effect of dilutive stock options and warrants | 2,744 |
| Assumed settlement of preferred securities with common shares | 2,681 |
| Weighted average common shares outstanding - diluted | 133,308 |
| Net earnings attributable to common shareholders | $ 569.8 |
| Dividend on preferred securities, net of tax | 6.0 |
| Revaluation of preferred securities | (1.0) |
| Diluted net earnings attributable to common shareholders | $ 574.8 |

| | | |
|---|---|---|
| Net earnings attributable to common shareholders per common share | | |
| Basic | $ | 4.46 |
| Diluted | $ | 4.31 |

| | | |
|---|---|---|
| Cash flow from operations attributable to common shareholders | $ | 2,254.0 |
| Dividend on preferred securities | | 10.4 |
| Diluted cash flow from operations attributable to common shareholders | $ | 2,264.4 |

| | | |
|---|---|---|
| Cash flow from operations attributable to common shareholders per common share | | |
| Basic | $ | 17.63 |
| Diluted | $ | 16.99 |

For the year ended December 31, 2002, 319,916 stock options with a weighted average exercise price of $48.33 (2001 - 692,790 stock options with a weighted average exercise price of $45.78, 2000 - 1,861,475 stock options with a weighted average exercise price of $44.38) were excluded from the calculation of per common share amounts as their effect on per common share amounts was anti-dilutive.

## 12. FINANCIAL INSTRUMENTS

### FINANCIAL CONTRACTS

The Company's financial instruments recognized in the consolidated balance sheets consist of cash, accounts receivable, accounts payable, accrued liabilities and long-term debt.

The estimated fair values of financial instruments have been determined based on the Company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The carrying value of cash, accounts receivable, accounts payable, accrued liabilities and long-term debt with variable interest rates approximate their fair value.

The estimated fair values of other financial instruments are as follows:

| | 2002 | | 2001 |
|---|---|---|---|
| | CARRYING VALUE | FAIR VALUE | CARRYING VALUE |
| ASSET (LIABILITY) | | | |
| Derivative financial instruments | $ - | $ 56.4 | $ - |
| Fixed rate notes | $ (3,259.6) | $ (3,573.2) | $ (1,328.6) |

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.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

The following summarizes transactions outstanding as at February 26, 2003, which includes all transactions outstanding at December 31, 2002:

| | REMAINING TERM | VOLUME | AVER |
|---|---|---|---|
| OIL | | | |
| Brent differential swaps | Jan. 2003 - Dec. 2003 | 15,000 bbls/d | |
| Oil price collars | Jan. 2003 - Mar. 2003 | 117,333 bbls/d | US $22.74 - |
| | Apr. 2003 - Jun. 2003 | 110,667 bbls/d | US $22.48 - |
| | Jul. 2003 - Sep. 2003 | 73,333 bbls/d | US $23.45 - |
| | Oct. 2003 - Dec. 2003 | 40,000 bbls/d | US $24.00 - |
| NATURAL GAS | | | |
| NYMEX collar | Jan. 2003 - Oct. 2003 | 30,000 mmbtu/d | US $ 2.88 - |
| Sumas fixed | Jan. 2003 - Oct. 2003 | 10,000 mmbtu/d | |
| AECO collars | Jan. 2003 - Mar. 2003 | 500,000 GJ/d | Cdn $4.16 - |
| | Apr. 2003 - Jun. 2003 | 240,000 GJ/d | Cdn $4.13 - |
| | Jul. 2003 - Sep. 2003 | 40,000 GJ/d | Cdn $3.50 - |
| | Oct. 2003 | 40,000 GJ/d | Cdn $3.50 - |

| | REMAINING TERM | AMOUNT ($ millions) |
|---|---|---|
| FOREIGN CURRENCY | | |
| Currency collars | Jan. 2003 - May 2003 | US $ 4.2/month |
| | Jan. 2003 - Aug. 2004 | US $25.0/month |

| | REMAINING TERM | AMOUNT ($ millions) | EXCHANGE RATE (US $/Cdn $) |
|---|---|---|---|
| Currency swap | Jan. 2003 - Dec. 2005 | US $125.0 | 1.55 |

| | REMAINING TERM | AMOUNT ($ millions) | FIXED RATE |
|---|---|---|---|
| INTEREST RATE | | | |
| Swaps - fixed into floating | Jan. 2003 - Jul. 2004 | US $200.0 | 6.70% |
| | Jan. 2003 - Jul. 2006 | US $200.0 | 6.70% |
| | Jan. 2003 - Jan. 2005 | US $200.0 | 7.20% |

| | | | |
|---|---|---|---|
| | Jan. 2003 - Jan. 2007 | US $200.0 | 7.20% |
| | Jan. 2003 - Oct. 2012 | US $200.0 | 5.45% |
| Swaps - floating into fixed | Jan. 2003 - Mar. 2004 | Cdn $100.0 | 5.08% |
| | Jan. 2003 - Mar. 2007 | Cdn $16.5 | 7.36% |

CREDIT RISK

Accounts receivable are mainly with customers in the oil and natural gas industry and are subject to normal industry credit risks. The Company minimizes this risk by entering into sales contracts with only highly rated entities. In addition, the Company reviews its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. The Company is also exposed to certain losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company minimizes this credit risk by entering into agreements with only highly rated financial institutions.

13. COMMITMENTS

The Company has committed to certain payments over the next five years as follows:

| | 2003 | 2004 | 2005 | |
|---|---|---|---|---|
| Natural gas transportation charges | $ 192.0 | $ 177.3 | $ 159.6 | $ |
| Oil transportation and pipeline charges | $ 12.9 | $ 14.6 | $ 13.3 | $ |
| Offshore equipment operating lease charges | $ 71.6 | $ 52.2 | $ 48.9 | $ |
| Electricity charges | $ 33.2 | $ 26.2 | $ 25.3 | $ |
| Office lease charges | $ 17.1 | $ 13.2 | $ 12.2 | $ |

14. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Interest paid | $ 132.2 | $ 127.4 | $ 169.3 |
| Taxes paid | $ 160.4 | $ 161.2 | $ 62.3 |





15. SEGMENTED INFORMATION

The Company's oil and natural gas activities are conducted in three geographic segments: North America, the North Sea and Offshore West Africa. These activities relate to the exploration, development, production and marketing of oil, natural gas liquids and natural gas.

The Company's Horizon Project has been classified as a separate segment at December 31, 2002. As the bitumen will be recovered through mining operations, this project constitutes a distinct segment from oil and natural gas activities. There are currently no revenues for this project and all directly related expenditures have been capitalized.

As a result of the Company's increasing midstream activities, the Company determined that effective January 1, 2002, the midstream activities within North America constitute a distinct operating segment. Midstream activities include the Company's pipeline operations and an electricity co-generation system.

| | Oil and Natural Gas | | | | |
|---|---|---|---|---|---|
| | North America | | | North | |
| | 2002 | 2001 | 2000 | 2002 | 2001 |
| REVENUE | | | | | |
| Revenue | $ 3,337.3 | $ 2,996.8 | $ 2,905.1 | $ 592.4 | $ 523. |
| Less: royalties | (564.2) | (551.3) | (491.1) | (32.7) | (27. |
| | 2,773.1 | 2,445.5 | 2,414.0 | 559.7 | 495. |
| Expenses | | | | | |
| Production | 656.4 | 596.4 | 492.0 | 228.8 | 123. |
| Depletion, depreciation and amortization | 1,032.8 | 747.1 | 585.9 | 193.3 | 129. |
| Administration | 61.0 | 37.1 | 26.4 | 0.3 | 0. |
| Interest | | 156.1 | 129.7 | 155.5 | 3. |
| Foreign exchange (gain) loss | (52.7) | 59.7 | 14.3 | 21.0 | 1. |
| Loss on sale of United States assets | - | 24.1 | - | - | |
| | 1,853.6 | 1,594.1 | 1,274.1 | 446.8 | 262. |
| Earnings before taxes | 919.5 | 851.4 | 1,139.9 | 112.9 | 232. |
| Taxes other than income tax | 11.1 | 8.5 | 12.3 | 51.1 | 59. |
| Current income tax | 21.2 | 15.1 | 14.7 | (19.6) | 61. |
| Future income tax | 322.5 | 290.4 | 466.5 | 82.5 | (9. |
| Net earnings | 564.7 | 537.4 | 646.4 | (1.1) | 120. |
| Dividend on preferred securities, net of tax | (6.0) | (5.9) | (2.8) | - | - |
| Revaluation of preferred securities | 1.0 | (7.5) | (1.6) | - | - |
| Net earnings attributable to common shareholders | $ 559.7 | $ 524.0 | $ 642.0 | $ (1.1) | $ 120. |

| | | | | Midstrea | |
|---|---|---|---|---|---|
| | Offshore West Africa | | | | |
| | 2002 | 2001 | 2000 | 2002 | 2001 |

| | | | | | |
|---|---|---|---|---|---|
| REVENUE | | | | | |
| Revenue | $ 101.5 | $ 41.6 | $ 34.6 | $ 52.0 | $ 27.4 |
| Less: royalties | (3.4) | (1.2) | - | - | - |
| | 98.1 | 40.4 | 34.6 | 52.0 | 27.4 |
| Expenses | | | | | |
| Production | 34.6 | 27.0 | 15.4 | 14.1 | 11.2 |
| Depletion, depreciation and amortization | 80.5 | 23.9 | 2.5 | 7.6 | 3.8 |
| Administration | - | - | - | - | - |
| Interest | 6.8 | (0.6) | (0.2) | - | - |
| Foreign exchange (gain) loss | - | 1.5 | (1.6) | - | - |
| Loss on sale of United States assets | - | - | - | - | - |
| | 114.5 | 52.2 | 16.3 | 21.7 | 15.0 |
| Earnings before taxes | (16.4) | (11.8) | 18.3 | 30.3 | 12.4 |
| Taxes other than income tax | 0.7 | 1.5 | 3.9 | - | - |
| Current income tax | 6.0 | - | - | - | - |
| Future income tax | (16.8) | (4.2) | 0.4 | 12.8 | 5.3 |
| Net earnings | (6.3) | (9.1) | 14.0 | 17.5 | 7.1 |
| Dividend on preferred securities, net of tax | - | - | - | - | - |
| Revaluation of preferred securities | - | - | - | - | - |
| Net earnings attributable to common shareholders | $ (6.3) | $ (9.1) | $ 14.0 | $ 17.5 | $ 7.1 |

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| REVENUE | | | |
| Revenue | $ 4,083.2 | $ 3,588.8 | $ 3,260.6 |
| Less: royalties | (600.3) | (580.3) | (506.2) |
| | 3,482.9 | 3,008.5 | 2,754 4 |
| Expenses | | | |
| Production | 933.9 | 757.9 | 571.0 |
| Depletion, depreciation and amortization | 1,314.2 | 903.8 | 644.6 |
| Administration | 61.3 | 37.6 | 27.2 |
| Interest | 158.9 | 137.8 | 162.3 |
| Foreign exchange (gain) loss | (31.7) | 62.8 | 15.9 |
| Loss on sale of United States assets | - | 24.1 | - |
| | 2,436.6 | 1,924.0 | 1,421.0 |
| Earnings before taxes | 1,046.3 | 1,084.5 | 1,333.4 |
| Taxes other than income tax | 62.9 | 69.1 | 49.5 |
| Current income tax | 7.6 | 76.9 | 48.4 |
| Future income tax | 401.0 | 282.5 | 464.0 |

| | | | |
|---|---|---|---|
| Net earnings | 574.8 | 656.0 | 771.5 |
| Dividend on preferred securities, net of tax | (6.0) | (5.9) | (2.8) |
| Revaluation of preferred securities | 1.0 | (7.5) | (1.6) |
| Net earnings attributable to common shareholders | $ 569.8 | $ 642.6 . | $ 767.1 |

CAPITAL EXPENDITURES

| 2002 | Cash Consideration | Non-cash Consideration | Capital Expenditures | Fai Adju |
|---|---|---|---|---|
| Oil and natural gas | | | | |
| North America - business combination | 843.2 | 1,550.0 | 2,393.2 | |
| North America - oil and natural gas | 1,026.3 | - | 1,026.3 | |
| North Sea | 323.3 | - | 323.3 | |
| Offshore West Africa | 185.3 | - | 185.3 | |
| | 2,378.1 | 1,550.0 | 3,928.1 | |
| Horizon Project | 68.1 | - | 68.1 | |
| Midstream | 20.4 | - | 20.4 | |
| Abandonments (2) | 42.9 | - | 42.9 | |
| Other | 9.9 | - | 9.9 | |
| | 2,519.4 | 1,550.0 | 4,069.4 | |

(1) Future income tax adjustments on non-tax base assets and other fair value adjustments.

(2) Abandonment expenditures were incurred in the following segments: $31.8 million North America, $8.6 million North Sea and $2.5 million Offshore West Africa (2001 - $9.4 million North America, $nil North Sea, $nil Offshore West Africa).

| 2001 | Cash Consideration | Non-cash Consideration | Capital Expenditures | Fai Adju |
|---|---|---|---|---|
| Oil and natural gas | | | | |
| North America - business combination | - | - | - | |
| North America - oil and natural gas | 1,443.2 | - | 1,443.2 | |
| North Sea | 97.5 | - | 97.5 | |
| Offshore West Africa | 203.9 | - | 203.9 | |
| | 1,744.6 | - | 1,744.6 | |
| Horizon Project | 26.8 | - | 26.8 | |

| | | | |
|---|---|---|---|
| Midstream | 97.3 | - | 97.3 |
| Abandonments (2) | 9.4 | - | 9.4 |
| Other | 6.4 | - | 6.4 |
| | 1,884.5 | - | 1,884.5 |





SEGMENTED PROPERTY, PLANT AND EQUIPMENT (NET)

| | 2002 | 2001 |
|---|---|---|
| Oil and natural gas | | |
| North America | $ 10,252.0 | $ 6,807.6 |
| North Sea | 1,277.0 | 865.6 |
| Offshore West Africa | 518.3 | 409.9 |
| Horizon Project | 228.7 | 160.6 |
| Midstream | 195.6 | 182.8 |
| Other | 28.0 | 16.4 |
| | $ 12,499.6 | $ 8,442.9 |

SEGMENTED ASSETS

| | 2002 | 2001 |
|---|---|---|
| Oil and natural gas | | |
| North America | $ 10,916.8 | $ 7,216.1 |
| North Sea | 1,426.6 | 941.0 |
| Offshore West Africa | 549.4 | 433.2 |
| Horizon Project | 228.7 | 160.6 |
| Midstream | 209.4 | 199.6 |
| Other | 28.0 | 16.4 |
| | $ 13,358.9 | $ 8,966.9 |

16. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Company's consolidated financial statements have been prepared in accordance with generally accepted accounting principles in Canada ("Canadian GAAP"). These principles conform in all material respects with those in the United States ("US GAAP") except for those noted below. Differences arising from US GAAP disclosure requirements are not addressed.

The application of US GAAP would have the following effects on consolidated net earnings as reported:

(millions of Canadian dollars, except per common share amounts)

| | NOTES | 2002 | 2001 | 2000 |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| Net earnings - Canadian GAAP | | $ 574.8 | $ 656.0 | $ 771.5 |
| Adjustments, net of tax | | | | |
| Depletion | (A) | 5.2 | 5.1 | 5.1 |
| Derivative financial instruments | (B) | 29.3 | 60.9 | (6.4) |
| Dividend on preferred securities | (C) | (6.0) | (5.9) | (2.8) |
| Revaluation of preferred securities | (C) | 1.0 | (7.5) | (1.6) |
| Tax effect of flow-through shares | (D) | (1.0) | - | - |
| Net earnings - US GAAP | | 603.3 | 708.6 | 765.8 |
| Net earnings - US GAAP per common share | | | | |
| Basic | | $ 4.72 | $ 5.84 | $ 6.56 |
| Diluted | | $ 4.56 | $ 5.70 | $ 6.38 |

Comprehensive income under US GAAP would be as follows:

| (millions of Canadian dollars) | NOTES | 2002 | 2001 | 2000 |
|---|---|---|---|---|
| Net earnings - US GAAP | | $ 603.3 | $ 708.6 | $ 765.8 |
| Adoption of FAS 133 | (B) | - | (124.5) | - |
| Amortization of FAS 133 adjustment | (B) | 31.1 | 54.1 | - |
| Foreign currency translation adjustment | (E) | (49.2) | 72.8 | - |
| Comprehensive income | | $ 585.2 | $ 711.0 | $ 765.8 |



The application of US GAAP would have the following effects on the consolidated balance sheets as reported:

| | | 2002 | | |
|---|---|---|---|---|
| (millions of Canadian dollars) | NOTES | CANADIAN GAAP | INCREASE (DECREASE) | US GAAP |
| Property, plant and equipment | (A) | $12,499.6 | $ (67.5) | $12,432.1 |
| Derivative financial instruments (asset) | (B) | $ - | $ (56.4) | $ (56.4) |
| Long-term debt | (C) | $ 4,074.0 | $ 126.4 | $ 4,200.4 |
| Future income tax | (A,B) | $ 3,187.4 | $ 4.3 | $ 3,191.7 |
| Shareholders' equity | | $ 4,868.1 | $ (141.8) | $ 4,726.3 |

| | | 2001 | | |
|---|---|---|---|---|
| (millions of Canadian dollars) | NOTES | CANADIAN GAAP | INCREASE (DECREASE) | US GAAP |
| Property, plant and equipment | (A) | $ 8,442.9 | $ (76.5) | $ 8,366.4 |
| Derivative financial instruments liability | (B) | - | $ 32.2 | $ 32.2 |
| Long-term debt | (C) | $ 2,669.2 | $ 127.4 | $ 2,796.6 |
| Future income tax | (A,B) | $ 1,767.3 | $ (27.7) | $ 1,739.6 |
| Shareholders' equity | | $ 3,807.0 | $ (208.4) | $ 3,598.6 |

NOTES:

(A) Using Canadian full cost accounting rules, costs capitalized in each cost centre, net of future income taxes and future site restoration costs, are limited to an amount equal to the undiscounted, unescalated future net revenues from proved reserves plus the lower of cost or estimated fair market value of unproved properties (the "ceiling test"). Under the full cost method of accounting as set forth by the US Securities and Exchange Commission, the ceiling test differs from Canadian GAAP in that future net revenues from proved reserves are discounted at 10% and estimated future financing and administrative expenses are not deducted from net revenues.

(B) The Company uses certain derivative financial instruments to manage its commodity prices and foreign currency exposure in relation to future firmly committed and anticipated sales transactions. The Company has also used interest rate swaps to manage its interest rate exposure. Under Canadian GAAP, these derivative financial instruments are accounted for as hedges.

Effective January 1, 2001, the Company adopted Statement of Financial Accounting Standards ("FAS") 133 "Accounting for Derivative Instruments and Hedging Activities" and FAS 138 "Accounting for Certain Derivative Instruments and Certain Hedging Activities" to account for its commodity prices and interest rate swap derivative financial instruments under US GAAP. Under FAS 133, all derivative financial instruments are recognized in the consolidated balance sheets at their fair value. Changes in the fair value of derivative financial instruments are recognized in consolidated net earnings unless specific criteria for hedging are met. In 2002 and 2001, no derivative financial instruments were designated as hedges for US GAAP purposes.

In 2001, the adoption of FAS 133 resulted in the Company recognizing a derivative financial instruments liability of $183.4 million and a charge to comprehensive income of $124.5 million, net of future income tax recoveries of $58.9 million. Of the initial liability recognized on January 1, 2001, a loss of $54.1 million, net of future income tax recoveries of $25.6 million, was reclassified to net earnings during 2001. For 2002, a loss of $31.1 million, net of future income tax recoveries of $14.5 million, was reclassified to net earnings.

Under US GAAP, foreign currency swap contracts used to hedge foreign currency exposure to anticipated, but not firmly committed, transactions cannot be accounted for as hedges under FAS 52, "Foreign Currency Translation". Accordingly, for US GAAP reporting, gains and losses from changes in the fair market value of foreign currency swap contracts related to these anticipated transactions are recognized in net earnings when those changes in market value occur.

(C) Under Canadian GAAP, the preferred securities are considered to be equity because the Company has the unrestricted right to pay dividends, principal and principal prepayments with common shares. Under US GAAP, the Company's preferred securities would be classified as long-term debt rather than as equity. Accordingly, the dividend on the preferred securities would be classified as interest expense rather than as a dividend and the revaluation of preferred securities would be included in foreign exchange (gain) loss in determining consolidated net earnings.

(D) Under Canadian GAAP, the future income tax effect of flow-through shares is deducted from share capital. However, under US GAAP, the future income tax effect of flow-through shares is expensed immediately.

(E) Under US GAAP, exchange gains and losses arising from the translation of self-sustaining foreign operations are included in comprehensive income.

(F) The Company has included transportation costs of $293.1 million, $84.2 million and $67.8 million as a reduction of oil and natural gas revenues for the years ended December 31, 2002, 2001 and 2000, respectively.





(G) Recently Issued Accounting Standards

ACCOUNTING FOR THE IMPAIRMENT OF LONG-LIVED ASSETS
In January 2003, the Canadian Institute of Chartered Accountants ("CICA") issued Section 3063 "Impairment of Long-lived Assets"indicates that impairment losses occur when the carrying value of the asset exceeds the sum of the undiscounted cash flows expected use and is measured as the amount by which the carrying amount exceeds its fair value. The effective date of the Section will be forbeginning on or after April 1, 2003. Application of the Section is prospective with earlier adoption encouraged. This Section will Company's midstream operating segment only.

ACCOUNTING FOR THE DISPOSAL OF LONG-LIVED ASSETS AND DISCONTINUED OPERATIONS
In January 2003, the CICA issued Section 3475 "Disposal of Long-lived Assets and Discontinued Operations". This Section outlines criteria for when a long-lived asset may be classified as held for sale and indicates that the value of such asset be measured at fair value less cost to sell. The Section also indicates that losses recognized do not include any expected future operating losses. Discontinued operations will be defined more broadly than previously. The effective date of the Section will apply to disposal activities initiated on or after May 1, 2003.

HEDGING
In December 2001, the CICA issued Accounting Guideline 13, "Hedging Relationships". This Guideline addresses the types of items that qualify for hedge accounting, the formal documentation required to enable the use of hedge accounting and the requiremen t to evaluate hedges for effectiveness. The Guideline does not specify how hedge accounting should be applied. The CICA has deferred the effective date of this Guideline by one year to fiscal years beginning on or after July 1, 2003. The Company is currently evaluating the impact of this Guideline on its consolidated financial statements.

ACCOUNTING FOR ASSET RETIREMENT OBLIGATIONS

In June 2001, the Financial Accounting Standards Board ("FASB") issued FAS 143 "Accounting for Asset Retirement Obligations". FAS 143 requires the recognition of the fair value of the retirement obligation for related long-lived tangible assets as a liability. Retirement costs equal to the retirement liability are capitalized as part of the cost of the related capital asset and amortized to expense over the life of the asset. This Standard is effective for fiscal years beginning on or after June 25, 2002. Adoption of this Standard may result in an adjustment to the future site restoration liability and to property, plant and equipment on the Company's consolidated balance sheets. The Canadian Accounting Standards Board (AcSB) has proposed a similar standard, which will be applicable for fiscal years beginning on or after January 1, 2004.

ACCOUNTING FOR COSTS ASSOCIATED WITH EXIT OR DISPOSAL ACTIVITIES

In July 2002, the FASB issued FAS 146, "Accounting for Costs Associated with Exit or Disposal Activities" to replace Emerging Issues Task Force Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an A ctivity (Including Certain Costs Incurred in a Restructuring)". FAS 146 requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of commitment to an exit or disposal plan. The Stan dard is effective for exit or disposal activities initiated after December 31, 2002.

ACCOUNTING GUIDANCE TO IMPROVE DISCLOSURE REQUIREMENTS FOR GUARANTEES

In November 2002, the FASB published Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others". The Interpretation expands on FAS 5, "Accounting for Contingencies", FAS 57, "Related Party Disclosures" and FAS 107, "Disclosures about Fair Value of Financial Instruments". It also incorporates, without change, Interpretation No. 34, "Disclosure of Indirect Guarantees". The Interpretation elaborates on the existing disclosure requirements for most guarantees. It also clarifies that at the time a company issues a guarantee, the company must recognize an initial liability for the fair value, or market value, of the obligations it assumes under that guarantee and must disclose that information in its interim and annual financial statements. The Interpretation is to be applied on a prospective basis to guarantees issued or modified after December 31, 2002, except for the disclosure requirements that are effective for interim or annual financial statements with periods ending after December 15, 2002. The Company is currently evaluating the impact of this Interpretation on its consolidated financial statements.