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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 40-F

[_] Registration Statement pursuant to section 12 of the Securities Exchange Act of 1934

[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, 2006 Commission File Number: 333-12138

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

ALBERTA
(Province or other jurisdiction of incorporation or organization)

1311
(Primary Standard Industrial Classification Code Numbers)

NOT APPLICABLE
(I.R.S. Employer Identification Number (if applicable))

2500, 855-2ND STREET S.W., CALGARY, ALBERTA, CANADA, T2P 4J8
TELEPHONE: (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 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:
TITLE OF EACH CLASS: 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

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.

537,903,260 Common Shares outstanding as of December 31, 2006

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Indicate by check mark whether the Registrant is furnishing the information contained in this Form 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 filing 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 [_]

This Annual Report on Form 40-F shall be incorporated by reference into, or as an exhibit to, as applicable, the Registrant's Registration Statement on Form F-9 (Registration No. 333-138873) under the Securities Act of 1933.

PRINCIPAL DOCUMENTS

The following documents have been filed as part of this Annual Report on Form 40-F, starting on the following page:

A. ANNUAL INFORMATION FORM

Annual Information Form of Canadian Natural Resources Limited ("Canadian Natural") for the year ended December 31, 2006.

B. AUDITED ANNUAL FINANCIAL STATEMENTS

Canadian Natural's audited consolidated financial statements for the years ended December 31, 2006 and 2005, including the auditors' report with respect thereto. For a reconciliation of important differences between Canadian and United States generally accepted accounting principles, see Note 16 of the notes to the consolidated financial statements.

C. MANAGEMENT'S DISCUSSION AND ANALYSIS

Canadian Natural's Management's Discussion and Analysis for the year ended December 31, 2006.

SUPPLEMENTARY OIL & GAS INFORMATION

For Canadian Natural's Supplementary Oil & Gas Information for the year ended December 31, 2006, see Exhibit 1 of this Annual Report on Form 40-F.

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CANADIAN NATURAL RESOURCES LIMITED

ANNUAL INFORMATION FORM

MARCH 28, 2007

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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:

"ARO" means Asset Retirement Obligation

"BBL" or "BARREL" means 34.972 Imperial gallons or 42 U.S. gallons.

"BCF" means one billion cubic feet.

"BBL/D" means barrels per day.

"BOE" means natural gas is converted to oil equivalent at the rate of six thousand cubic feet equals one barrel of oil equivalent.

"CANADIAN NATURAL RESOURCES LIMITED", "CANADIAN NATURAL", 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.

"CBM" means coalbed methane

"CONVENTIONAL CRUDE OIL, NGLS AND NATURAL GAS" includes all of the Company's light and medium crude oil, heavy crude oil, thermal in-situ, natural gas, coal bed methane and natural gas liquid activities. It does not include the Company's oil sands mining assets.

"DEVELOPMENT WELL" means a well drilled into a zone that is known to be productive and expected to produce crude oil or natural gas in the future.

"DRY WELL" means a well drilled that is not capable of producing commercial quantities of crude oil or natural gas to justify completion. A dry well will be plugged back, abandoned and reclaimed.

"EXPLORATORY WELL" means a well drilled into an unproven territory with the intention to discover commercial quantities of crude oil or natural gas.

"FPSO" means a Floating Production, Storage and Offtake vessel.

"GHG" means greenhouse gas.

"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.

"HORIZON PROJECT" means the Horizon Oil Sands Project

"MBBL" means one thousand barrels.

"MCF" means one thousand cubic feet.

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

"MMBBL" 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.

"PRODUCTIVE WELL" means a well that is not a dry well.

"PRT" means Petroleum Revenue Tax

"SAGD" means steam-assisted gravity drainage.

"UNDEVELOPED 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.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this document or documents incorporated herein by reference for Canadian Natural Resources Limited (the "Company") may constitute "forward-looking statements" within the meaning of the United States Private Securities 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 "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 or insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the availability and cost of seismic, drilling and other equipment; ability of the Company to complete its capital programs; 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 ability of the Company to attract the necessary labour required to build its projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas; availability and cost of financing; success of exploration and development activities; timing and success of integrating the business and operations of acquired companies; 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); asset retirement obligations; 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, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Statements relating to "reserves" are 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 were 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.

Except as required by law, the Company assumes no obligation to update forward-looking statements should circumstances or the Company's estimates or opinions change.

SPECIAL NOTE REGARDING CURRENCY, PRODUCTION AND RESERVES

In this document, all references to dollars refer to Canadian dollars unless otherwise stated. Reserves and production data is presented on a before royalties basis unless otherwise stated. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("boe"). A boe is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6mcf:1bbl). This conversion may be misleading,

particularly if used in isolation, since the 6mcf:1bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head.

For the year ended December 31, 2006, the Company retained qualified independent reserve evaluators, Sproule Associates Limited ("Sproule") and Ryder Scott Company ("Ryder Scott") to evaluate 100% of the Company's conventional proved, as well as proved and probable crude oil, natural gas liquids ("NGL") and natural gas reserves (not including the Company's oil sands mining assets) and prepare Evaluation Reports on these reserves. Sproule evaluated the Company's North America conventional assets and Ryder Scott evaluated the international conventional assets. The Company has been granted an exemption from National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada. This exemption allows the Company to substitute United States Security and Exchange Commission ("SEC") requirements for certain disclosures required under NI 51-101. There are two principal differences between the two standards (i) the requirement under NI 51-101 to disclose both proved and proved and probable reserves, as well as the related net present value of future net revenues using forecast prices and costs; and, (ii) the definition of proved reserves used by the SEC to that of NI 51-101. However with respect to the definition of proved reserves, as discussed in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), the standards that NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs should not be material.

For the year ended December 31, 2006, the Company retained a qualified independent reserves evaluator, GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate 100% of Phases 1 through 3 of the Company's Horizon Oil Sands Project ("Horizon Project") and prepare an Evaluation Report on the Company's proved, as well as proved and probable oil sands mining reserves incorporating both the mining and upgrading projects. These reserves were evaluated adhering to the requirements of SEC Industry Guide 7 using year-end constant pricing and have been disclosed separately from the Company's conventional proved and probable crude oil, NGLs and natural gas reserves.

The Company has disclosed proved conventional reserves and the Standardized Measure of discounted future net cash flows using year-end constant prices and costs as mandated by the SEC in the supplementary crude oil and natural gas information section of the Company's Annual Report. The Company has elected to provide the net present value of these same conventional proved reserves as well as its conventional proved and probable reserves and the net present value of these reserves under the same parameters as additional voluntary information. Net present values of conventional reserves are based upon discounted cash flows prior to the consideration of income taxes and existing asset abandonment liabilities. Only future development costs and associated material well abandonment liabilities have been applied.The Company has also elected to provide both proved, and proved and probable conventional reserves and the net present value of these reserves using forecast prices and costs as voluntary additional information, which is disclosed in this Annual Information Form.

The Reserve Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of Sproule, Ryder Scott and GLJ to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and net present value of remaining conventional crude oil, NGLs and natural gas reserves as well as the Company's quantity of oil sands mining reserves.

SPECIAL NOTE REGARDING NON-GAAP FINANCIAL MEASURES

Management's Discussion and Analysis ("MD&A") includes references to financial measures commonly used in the crude oil and natural gas industry, such as cash flow from operations, adjusted net earnings from operations and net asset value. These financial measures are not defined by generally accepted accounting principles ("GAAP") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with Canadian GAAP, as an indication of the Company's performance.

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. Canadian Natural 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.

Canadian Natural 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 ("Ranger"), including its subsidiaries, in July 2000. On October 1, 2000 Ranger 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.

On January 1, 2004 CanNat and the Company amalgamated pursuant to the BUSINESS CORPORATIONS ACT (Alberta) under the name Canadian Natural Resources Limited.

On September 14, 2006, the Company announced entering into an agreement to acquire Anadarko Canada Corporation, a subsidiary of Anadarko Petroleum Corporation for net cash consideration of $4,641 million including working capital and other adjustments. Pursuant to a Purchase and Sale Agreement, the Company acquired all of the outstanding shares of Anadarko Canada Corporation effective November 2, 2006. On November 3, 2006 Anadarko Canada Corporation and a wholly owned subsidiary of the Company, 1266701 Alberta Ltd. amalgamated to form ACC-CNR Resources Corporation. Subsequently, on January 1, 2007, ACC-CNR Resources Corporation and Canadian Natural Resources Limited amalgamated and the amalgamated company continued under the name Canadian Natural Resources Limited.

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

NAME OF COMPANY	JURISDICTION OF INCORPORATION
CanNat Energy Inc.	Delaware
CNR (ECHO) Resources Inc.	Alberta
CNR International (U. K.) Investments Limited	England
CNR International (U. K.) Limited	England
CNR International Cote d'Ivoire SARL	Cote d'Ivoire
CNR International (Olowi) Limited	Bahamas
Horizon Construction Management Ltd.	Alberta
Renata Resources Inc.	Alberta

Canadian Natural, as the managing partner, CNR (ECHO) Resources Inc. and Renata Resources Inc. are the partners of Canadian Natural Resources, a general partnership. Canadian Natural, as the managing partner, CNR (ECHO) Resources Inc., Renata Resources Inc., and Canadian Natural Resources are partners of Canadian Natural Resources Northern Alberta Partnership, a general partnership. The two partnerships hold the majority of the producing Canadian crude oil and natural gas properties of Canadian Natural. Canadian Natural, as the managing partner, and 1081840 Alberta Ltd. are the partners of 1081840 Alberta Partnership, which holds certain crude oil and natural gas properties of the Company situated in Alberta. Canadian Natural, as the managing partner, and CNR 2006 ULC are the partners of CNR 2006 Partnership, which holds certain crude oil and natural gas properties situated in the provinces of Alberta, Saskatchewan and British Columbia and in the Yukon Territories.The Company also has a 15 per cent interest in Cold Lake Pipeline Ltd., which is the general partner of Cold Lake Pipeline Limited Partnership in which Canadian Natural holds a separate 14.7 per cent partnership interest. Canadian Natural, as the managing partner, and Renata Resources Inc. are the partners of Canadian Natural Resources 2005 Partnership, a general partnership which holds certain natural gas facilities situated in Alberta.

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

GENERAL DEVELOPMENT OF THE BUSINESS

Canadian Natural'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 NGLs, natural gas and bitumen production.

The Company initiates, operates and maintains a large working interest in a majority of the prospects in which it participates. Canadian Natural's objective is to increase cash flow and net 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, 2006 the Company had 3,360 permanent employees in North America and 340 permanent employees in its international operations.

In February 2004, the Company completed the acquisition of certain resource properties located in East Central Alberta and Saskatchewan (collectively known as the Petrovera Partnership) for aggregate consideration of $701 million. In a separate transaction, the Company sold specific resource properties in the Petrovera Partnership, representing approximately one third of the total acquisition, to another independent producer for proceeds of $234 million, resulting in a net cost of $467 million for the retained properties. The net production from the working interests at the time of the acquisition retained by the Company was approximately 27.5 mbbl/d of heavy crude oil and 9 mmcf/d of natural gas together with volumes associated with royalty interests of 1.2 mbbl/d of heavy oil and 2 mmcf/d of natural gas. All of the retained properties are situated in the Company's core region of Northern Plains.

In April 2004, the Company completed an acquisition of certain crude oil and natural gas properties located in Northeast British Columbia and Northwest Alberta for consideration of $280 million. The properties at the time of acquisition were producing approximately 68 mmcf/d of natural gas and 200 bbl/d of light crude oil and NGLs and contained over 415 thousand acres of developed and undeveloped land. The properties included a further interest in the Ladyfern natural gas field. The portion of the Ladyfern field included in the acquisition included production of approximately 50 mmcf/d of natural gas. As part of this acquisition, the Company also acquired undeveloped acreage in the Foothills area of Alberta and British Columbia. This area is characterized by large, undeveloped pools with significant natural gas potential in deeper zones and has added a new exploration base in the Alberta Foothills, complementing the Company's existing holdings and production base in the British Columbia Foothills.

In the third quarter of 2004, the Company's wholly owned subsidiary CNR International (U.K.) Limited acquired certain crude oil and natural gas properties in the central North Sea. The acquired properties comprise operated interests in T-Block (Tiffany, Toni and Thelma fields) and B-Block (Balmoral, Stirling and Glamis fields) together with associated production facilities and adjacent exploration acreage.

On December 1, 2004, the Company issued US$350.0 million of 10 year 4.90 per cent unsecured notes maturing December 1, 2014 and US$350.0 million of 30 year 5.85 per cent unsecured notes maturing February 1, 2035 pursuant to a short form shelf prospectus dated May 8, 2003.

In December 2004, the Company acquired certain crude oil and natural gas properties located in Alberta and British Columbia, for an aggregate cash consideration of approximately $703 million, net of proceeds received from an agreement to concurrently dispose of a portion of such properties for approximately $50 million and cash flows realized from the effective date of September 1, 2004. At the time of the acquisition production from the properties acquired by Canadian Natural, after the above noted disposition, was estimated at 105 mmcf/d of natural gas and 7.5 mbbl/d of light crude oil and NGLs. The acquisition included over 510,000 net acres of undeveloped land. The vast majority of the acquired properties is located in the Company's core regions and extends its Northern Plains core region into the light crude oil operating area of Dawson.

During 2004, the Company completed 109 transactions (including the four acquisitions mentioned above) in the normal course to acquire additional interests in crude oil and natural gas properties at an aggregate net expenditure of $1.371 billion (excluding the Petrovera Partnership acquisition described above). 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 $7 million.

In February 2005, the Board of Directors of the Company approved Phase 1 of the Horizon Project. The Horizon Project is designed as a phased development and includes the mining of bitumen combined with an onsite upgrader. Phase 1 production is planned to begin in the second half of 2008 at 110 mbbl/d of 34(degree) API light, sweet synthetic crude oil ("SCO"). Future expansion using a phased approach would further increase production to 232 mbbl/d of SCO. The phased approach provides the Company with improved cost and project controls including labour and materials management, and directionally mitigates the effects of growth on local infrastructure.

Based upon stratigraphic drilling and the Company's own internal estimates it is believed that the Company's oil sands leases located near Fort McMurray, Alberta contain an estimated 6 billion barrels of potentially recoverable bitumen using existing mining and upgrading technologies. Additional in-situ potential also exists on the western portions of the leases. The first three phases of the Horizon Project, which encompasses only a portion of these oil sands leases, will deliver approximately 37 years of production without the declines normally associated with petroleum operations. GLJ Petroleum Consultants Ltd. ("GLJ"), a qualified independent third party petroleum consultant firm, was retained by the Reserves Committee of Canadian Natural's Board of Directors to evaluate the mining reserves associated with the Horizon Project. Their report estimated that 3.5 billion barrels of gross lease proved and probable bitumen reserves are located on the leases associated with the first three phases of the Horizon Project.

In August 2005, the Company entered into an agreement to obtain pipeline transportation service for the Horizon Project. This agreement allows Canadian Natural to gain access to major sales pipelines out of Edmonton for the Company's synthetic crude oil which will be produced at the Horizon Project, while at the same time provides significant quality benefits associated with being the only shipper on the Horizon Pipeline. The expected twinning of the existing Alberta Oil Sands Pipeline ("AOSPL"), resulting in two parallel pipelines, one of which will be dedicated to Canadian Natural, combined with a new pipeline constructed from the Horizon Project site down to the AOSPL Terminal (collectively, the "Horizon Pipeline"), will provide crude oil transportation service for the Horizon Project. The initial term of the agreement is 25 years, which will commence on the in-service date. In addition to having the option to renew the agreement for successive 10-year terms, Canadian Natural has the right to request incremental expansions of the Horizon Pipeline based upon applicable National Energy Board approved multi-pipeline economics. The construction of the Horizon Pipeline began in 2006 and is expected to be fully operational by mid 2008 to coincide with first production at the Horizon Project. See below "Horizon Oil Sands Project".

In April 2005, the Company monetized, through a sale, a large portion of its overriding royalty interests on various producing properties throughout Western Canada and Ontario for proceeds of approximately $345 million. In 2004 these interests produced approximately 3,700 boe/d and over the 2003 and 2004 fiscal years cash flow from these interests averaged approximately $50 million per year. As part of the transaction, the Company purchased 3,858,520 trust units of Freehold Royalty trust for $60 million and, after the mandatory hold period, the trust units were sold to an underwriting group pursuant to an agreement for a net gain of approximately $11 million.

On June 1, 2005, the Company issued $400 million of 10 year 4.95 per cent unsecured notes maturing June 1, 2015 pursuant to a short form shelf prospectus for the issuance of medium term notes in Canada dated August 1, 2003.

During 2005, the Company completed 96 transactions in the normal course to acquire additional interests in crude oil and natural gas properties at an aggregate net expenditure of $134 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 a large portion of its overriding royalty interests and operated and non-operated properties not located in the Company's core regions for proceeds of $454 million.

In January 2006 the Company issued a further $400 million of 4.50 per cent unsecured notes maturing January 23, 2013 as the first issuance under the short form Canadian base shelf prospectus dated August 29, 2005, which allows for the issuance of debt securities in an aggregate principal amount of up to C$2 billion.

On August 17, 2006, the Company issued US$250.0 million of 10 year 6.0 per cent unsecured notes maturing August 15, 2016 and US$450.0 million of 30 year 6.50 per cent unsecured notes maturing February 15, 2037 pursuant to a short form base shelf prospectus dated June 3, 2005.

In November 2006, the Company completed the acquisition of Anadarko Canada Corporation ("ACC") for net cash consideration of $4,641 million, including working capital and other adjustments. The Company immediately integrated ACC into its ongoing operations. The land and production base acquired are located substantially in Western Canada and are natural gas weighted assets with a long reserve life. The assets produce in excess of 350 mmcf/d of natural gas and approximately 9,000 bbl/d of light crude oil and NGLs production. The assets acquired also include approximately 1.5 million net undeveloped acres and key strategic facilities in Northeast British Columbia and Northwest Alberta. In conjunction with the closing of the acquisition of ACC, the Company executed a $3,850 million, three-year non-revolving syndicated credit facility maturing in October 2009. This facility is subject to certain prepayment requirements up to a maximum of $1,500 million.

During 2006, the Company completed 83 transactions in the normal course to acquire additional interests in crude oil and natural gas properties. The aggregate net expenditure of the transactions was $4,801 million, including the ACC acquisition of $4,755 million. The properties acquired are located in the Company's principal operating regions and are comprised of producing and non-producing leases together with related facilities. As well the Company participated in 48 transactions to dispose of non-core operated and non-operated properties for proceeds of $68 million. Included in this amount is a royalty disposition for $66 million.

On March 19, 2007, the Company issued US$1,100 million of 10 year 5.70 per cent unsecured notes maturing May 15, 2017 and US$1,100 million of 30 year 6.25 per cent unsecured notes maturing March 15, 2038 pursuant to a short form base shelf prospectus dated November 27, 2006. Concurrently, the Company entered into cross-currency interest-rate swaps to fix the Canadian dollar interest and principal repayment amounts on US$1,100 million of unsecured notes due May 15, 2017 at 5.10% and C$1,287 million. The Company also entered into a cross-currency interest-rate swap to fix the Canadian dollar interest and principal repayment amounts on US$550 million of unsecured notes due March 15, 2038 at 5.76% and C$644 million.

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 government legislation and regulations, which govern exploration, development, production, refining, marketing, prevention of waste and other activities.

The Company's Canadian properties are primarily located in Alberta, British Columbia, Saskatchewan, Manitoba and the Northwest and Yukon 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 the provinces of 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 and Yukon 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 approval of a 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. A 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 NGLs from each province. Government royalties are payable on NGLs, 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.

In addition to government royalties, the Company is currently subject to federal and provincial income taxes in Canada at a combined rate of approximately 34.91 per cent after allowable deductions.

UNITED KINGDOM

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

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. Approvals granted on or after March 16, 1993 are exempted from PRT and government royalties. 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 deductible for CT purposes. The CT rate, which became effective April 1, 1999, was set at 30 per cent. In its 2002 budget speech by the UK Chancellor of the Exchequer, the UK Government announced changes to taxation policies on UK North Sea crude oil and natural gas production. A Supplementary Charge Tax ("SCT") 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. During 2005, the UK Chancellor of the Exchequer announced a further increase to the SCT of 10% to 20% on profits from UK North Sea crude oil and natural gas production, effective January 1, 2006. In December 2006, the UK Government announced the abolition of PRT on profits of decommissioned fields subsequently redeveloped, subject to certain conditions being met.

OFFSHORE WEST AFRICA

Terms of licences, including royalties and taxes payable on production or profit sharing arrangements, vary by country and, in some cases, by concession within each country. Development of the Espoir field on CI-26 and the Baobab Field on CI-40, in Cote d'Ivoire, are subject to production sharing arrangements that provide 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"). In August 2006, the Government of Cote d'Ivoire announced a reduction in the rate of Corporate Income Tax from 35 to 27 per cent, effective January 1, 2006.

In October 2005, Canadian Natural completed the acquisition of the permit to develop the Olowi Field, offshore Gabon and received approval of its development plan for this acquisition from the Gabonese Government in early 2006 and from Canadian Natural's Board of Directors in November 2006. Development of this field 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.

RISK FACTORS

VOLATILITY OF CRUDE OIL AND NATURAL GAS PRICES

The Company's financial condition is substantially dependent on, and highly sensitive to, the prevailing prices of crude oil and natural gas. Fluctuations in crude oil or natural gas prices could have a material adverse effect on the Company's operations and financial condition and the value and amount of its reserves. Prices for crude oil and natural gas fluctuate in response to changes in the supply of and demand for, crude oil and natural gas, market uncertainty and a variety of additional factors beyond the Company's control. Crude oil prices are determined by international supply and demand. Factors which affect crude oil prices include the actions of the Organization of Petroleum Exporting Countries, the condition of the Canadian, United States, European and Asian economies, government regulation, political stability in the Middle East and elsewhere, the foreign supply of crude oil, the price of foreign imports, the availability of alternate fuel sources and weather conditions. Natural gas prices realized by the Company are affected primarily in North America by supply and demand, weather conditions and prices of alternate sources of energy. Any substantial or extended decline in the prices of crude oil or natural gas could result in a delay or cancellation of existing or future drilling, development or construction programs or curtailment in production at some properties or resulting unutilized long-term transportation commitments,

all of which could have a material adverse effect on Canadian Natural's revenues, profitability and cash flows.

Canadian Natural conducts an annual assessment of the carrying value of its assets in accordance with Canadian GAAP. If crude oil and natural gas prices decline, the carrying value of the assets could be subject to downward revisions, and net earnings could be adversely affected.

Approximately 27 percent of the Company's 2006 production on a boe basis was primary and thermal heavy crude oil. The market prices for heavy crude oil differ from the established market indices for light and medium grades of crude oil, due principally to the higher transportation and refining costs associated with heavy crude oil. As a result, the price received for heavy crude oil is generally lower than the price for medium and light crude oil, and the production costs associated with heavy crude oil may be higher than for lighter grades. Future differentials are uncertain and any increase in the heavy crude oil differentials could have a material adverse effect on the Company's business.

ENVIRONMENTAL RISKS

All phases of the crude oil and natural gas business are subject to environmental regulation pursuant to a variety of Canadian, United States, United Kingdom, European Union and other federal, provincial, state and municipal laws and regulations, as well as international conventions (collectively, "environmental legislation").

Environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. Environmental legislation also requires that wells, facility sites and other properties associated with the Company's operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and significant changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications. Compliance with environmental legislation can require significant expenditures and failure to comply with environmental legislation may result in the imposition of fines and penalties. The costs of complying with environmental legislation in the future may have a material adverse effect on Canadian Natural's financial condition or results of operations.

The crude oil and natural gas industry is experiencing incremental increases in costs related to environmental regulation, particularly in North America and the North Sea. Existing and expected legislation and regulations will require the Company to address and mitigate the effect of its activities on the environment. This will include dismantling production facilities and remediating damage caused by the disposal or release of specified substances. Increasingly stringent laws and regulations may have an adverse effect on the Company's future net earnings and cash flow from operations.

The Company's associated risk management strategies focus on working with legislators and regulators to ensure that any new or revised policies, legislation or regulations properly reflect a balanced approach to sustainable development. Specific measures in response to existing or new legislation include a focus on the Company's energy efficiency, air emissions management, released water quality, reduced fresh water use and the minimization of the impact on the landscape. The Company's strategy employs an Environmental Management Plan known as the Stewardship Report (the "Plan"), a detailed copy of of the Plan is presented to, and reviewed by, Health, Safety and

Environmental Committee of the Board of Directors annually. The Plan is updated quarterly at the Health, Safety and Environmental Committee meetings.

The Company's Plan and operating guidelines focus on minimizing the impact of operations while meeting regulatory requirements and internal corporate standards. The Company, as part of this Plan, has implemented a proactive program that includes:

o An annual internal environmental compliance audit and inspection program of the Company's operating facilities;

o A suspended well inspection program to support future development or eventual abandonment;

o Appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment;

o An effective surface reclamation program;

o A due diligence program related to groundwater monitoring;

o An active program related to preventing and reclaiming spill sites;

o A solution gas reduction and conservation program; and

o A program to replace the majority of fresh water for steaming with brackish water.

The Company has also established stringent operating standards in four areas:

1. The use of water-based, environmentally friendly drilling muds;

2. Implementing cost effective ways of reducing greenhouse gas emissions per unit of production;

3. Exercising care with respect to all waste produced through effective waste management plans; and

4. Minimizing produced water volumes onshore and offshore through cost-effective measures.

In 2006, the Company's capital expenditures included $75 million for abandonment expenditures, an increase from $46 million in 2005 (2004 - $32 million).

The Company's estimated undiscounted ARO at December 31, 2006 was as follows:

<TABLE>
<CAPTION>

Estimated ARO, undiscounted ($millions)	2006	2005
<S>	<C>	<C>
North America	$ 2,826	$ 2,050
North Sea	1,543	1,185
Offshore West Africa	128	90
	4,497	3,325
North Sea PRT recovery	(625)	(370)
	$ 3,872	$ 2,955

</TABLE>

The estimate of the ARO is based on estimates of future costs to abandon and restore the wells, production facilities and offshore production platforms. Factors that affect costs include number of wells drilled, well depth and the specific environmental legislation. The estimated costs are based on engineering estimates using current costs in accordance with present legislation and industry operating practice. 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. The future abandonment costs incurred in the North Sea are expected to result in an estimated PRT recovery of $625 million (2005 - $370 million), as abandonment costs are an allowable deduction in determining PRT and may be carried back to reclaim PRT previously paid. The expected PRT recovery reduces the Company's net abandonment liability to $3,872 million (2005 - $2,955 million).

GREENHOUSE GAS ("GHG") AND OTHER AIR EMISSIONS

The Company is concurrently working with legislators and regulators on the design of new greenhouse gas emission laws and regulations and is pursuing an integrated emissions reduction strategy, to ensure the Company is able to comply with existing and future emission reductions requirements. The Company continues to develop strategies that will enable it to deal with the risks and opportunities associated with new climate change policies. In addition, the Company is working with relevant parties to ensure that new policies encourage innovation, energy efficiency, targeted research and development while not impacting competitiveness.

The Company continues to work with Canadian federal and provincial governments on the regulatory framework for greenhouse gases for larger emitters. The Company is actively promoting a harmonized regulatory framework between the two levels of government. Both levels of government have indicated that existing legislation will be amended in 2007 to create further requirements for reporting emissions, facility-based emission intensity targets and regulatory compliance. Compliance with emission intensity targets is expected for 2008 and possibly a part of 2007 for larger facilities in Alberta.

Issues to be resolved include, but are not limited to: the outcome of discussions between the Federal and Provincial Governments, the impact of implementing legislation, the allocations of reduction obligations among industry sectors and international developments.

Canadian Natural anticipates that changes in environmental legislation may require, among other things, reductions in emissions to the air from its operations. Any required reductions in the greenhouse gases emitted from the Company's operations could increase capital expenditures and operating expenses, especially those related to the Horizon Project and the Company's other existing and planned large oil sands projects. This may have an adverse effect on the Company's net earnings and cash flow from operations. Future changes in environmental legislation could result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse effect on the Company's financial condition or results of operations.

NEED TO REPLACE RESERVES

Canadian Natural's future crude oil and natural gas reserves and production, and therefore its cash flows and results of operations, are highly dependent upon success in exploiting its current reserve base and acquiring or discovering additional reserves. Without additions to reserves through exploration, acquisition or development activities, the Company's production will decline over time as reserves are depleted. The business of exploring for,

developing or acquiring reserves is capital intensive. To the extent the Company's cash flows from operations are insufficient to fund capital expenditures and external sources of capital become limited or unavailable, the Company's ability to make the necessary capital investments to maintain and expand its crude oil and natural gas reserves will be impaired. In addition, Canadian Natural may be unable to find and develop or acquire additional reserves to replace its crude oil and natural gas production at acceptable costs.

COMPETITION IN ENERGY INDUSTRY

The energy industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of supply, the construction and operation of crude oil and natural gas pipelines and facilities, the acquisition of crude oil and natural gas interests and the transportation and marketing of crude oil, natural gas, NGLs and electricity. Canadian Natural will compete not only among participants in the energy industry, but also between petroleum products and other energy sources. The Company's competitors will include integrated oil and natural gas companies and numerous other senior oil and natural gas companies, some of which may have greater financial and other resources than the Company.

OTHER BUSINESS RISKS

Other business risks relate to operational risks, the cost of capital available to fund exploration and development programs, fluctuation in foreign exchange rates, the availability of skilled labour and manpower, regulatory issues and taxation and the requirements of new environmental laws and regulations. Exploring for, producing and transporting petroleum substances involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. These activities are subject to a number of hazards which may result in fires, explosions, spills, blow-outs or other unexpected or dangerous conditions causing personal injury, property damage, environmental damage and interruption of operations. The Company has developed a comprehensive health and safety management framework to mitigate physical risks. The Company also mitigates insurable risks to protect against significant losses by maintaining a comprehensive insurance program, while maintaining levels and amounts of risk within the Company which management believes to be acceptable. However, Canadian Natural's liability, property and business interruption insurance may not and possibly will not provide adequate coverage in all circumstances.

FOREIGN INVESTMENTS

The Company's foreign investments involve risks typically associated with investments in developing countries such as uncertain political, economic, legal and tax environments. These risks may include, among other things, currency restrictions and exchange rate fluctuations, loss of revenue, property and equipment as a result of hazards such as expropriation, nationalization, war, insurrection and other political risks, risks of increases in taxes and governmental royalties, renegotiation of contracts with governmental entities and quasi-governmental agencies, changes in laws and policies governing operations of foreign-based companies and other uncertainties arising out of foreign government sovereignty over the Company's international operations. In addition, if a dispute arises in its foreign operations, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of a court in the United States or Canada.

Canadian Natural's private ownership of crude oil and natural gas properties in Canada differs distinctly from its ownership interests in foreign crude oil and natural gas properties. In some foreign countries in which the Company does and

may do business in the future, the state generally retains ownership of the minerals and consequently retains control of, and in many cases participates in, the exploration and production of reserves. Accordingly, operations outside of Canada may be materially affected by host governments through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses and other charges. In addition, changes in prices and costs of operations, timing of production and other factors may affect estimates of crude oil and natural gas reserve quantities and future net cash flows attributable to foreign properties in a manner materially different than such changes would affect estimates for Canadian properties. Agreements covering foreign crude oil and natural gas operations also frequently contain provisions obligating the Company to spend specified amounts on exploration and development, or to perform certain operations or forfeit all or a portion of the acreage subject to the contract.

UNCERTAINTY OF RESERVE ESTIMATES

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond the Company's control. In general, estimates of economically recoverable crude oil, NGLs and natural gas reserves and the future net cash flow therefrom are based upon a number of factors and assumptions made as of the date on which the reserve estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable crude oil, NGLs and natural gas reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Canadian Natural's actual production, revenues, taxes and development, abandonment and operating expenditures with respect to its reserves will likely vary from such estimates, and such variances could be material.

Estimates with respect to reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves.

PRIORITY OF SUBSIDIARY INDEBTEDNESS; CONSEQUENCES OF HOLDING CORPORATION STRUCTURE

The Company carries on business through corporate and partnership subsidiaries. The majority of the Company's assets are held in one or more corporate or partnership subsidiaries. The results of operations and ability to service indebtedness, including debt securities, are dependent upon the results of operations of these subsidiaries and the payment of funds by these subsidiaries to the Company in the form of loans, dividends or other means employed for the payment of funds to the Company. In the event of the liquidation of any corporate or partnership subsidiary, the assets of the subsidiary would be used first to repay the indebtedness of the subsidiary, including trade payables or obligations under any guarantees, prior to being used by the Company to pay its indebtedness.

ENVIRONMENTAL MATTERS

The Company carries out its activities in compliance with all relevant regional, national and international regulations and industry standards. 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 in turn reports on environmental matters directly to the Health, Safety and Environmental Committee of 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 by changes in applicable legislation. 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 management 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 environmental compliance audit and inspection program of its 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. Canadian Natural participates in both the Canadian federal and provincial regulated GHG emissions reporting for facilities with GHG emissions greater than 100 thousand tonnes of CO2 equivalent per year. The Company continues to quantify annual GHG emissions for internal reporting purposes. The Company has participated in the Canadian Association of Petroleum Producers ("CAPP") Stewardship Program since 2000 and is currently a Gold Level Reporter. Canadian Natural continues to invest in proven and new technologies and in improved operating strategies to help us achieve our overall goal of a net reduction of GHG emissions per unit of production.

Canadian Natural is committed to managing air emissions through an integrated corporate approach which considers opportunities to reduce both air pollutants and GHG emissions. Air quality programs continue to be an essential part of our environmental work plan and are operated within all regulatory standards and guidelines. Our strategy for managing GHG emissions is based on four core principles: energy conservation and efficiency; reduced intensity; innovative technology and associated research and development; and, trading capacity; both domestically and globally.

The Company continues to implement flaring, venting and fuel and solution gas conservation programs. In 2006 the Company completed approximately 122 gas conservation projects, resulting in reduction of 1.24 million tonnes/year of carbon dioxide equivalents ("CO2E"). Over the past five years the Company has spent over $100 million to conserve the equivalent of over 5 million tonnes of CO2E. In heavy crude oil production Canadian Natural is evaluating tank heater efficiciencies in an effort to conserve fuel gas at facilities with field tanks. The Company also monitors the performance of its compressor fleet and it is continually modified and optimized for maximum efficiency. Another project of note is the trial of "no emissions" chemical injection pumps which are designed to eliminate fuel gas venting. These programs also influence and

direct the Company's plans for new projects and facilities. It is planned that the Horizon Project will incorporate advancements in technology to reduce further GHG emissions through maximizing heat integration, the use of cogeneration to meet steam and electricity demands and the design of the hydrogen production facility to enable carbon dioxide ("CO2") capture.

In its North Sea operations the Company is operating below its CO2 allocation and continues to implement an improvement program based on efficiency audits of its major facilities. Canadian Natural also began a Produced Water Re-injection trial which has resulted in re-injecting approximately 30 thousand barrels of produced water each day.

The costs incurred by the Company for compliance with environmental matters and site restoration exceeded three per cent of the total exploration and development expenditures incurred by the Company in each of the years ended December 31, 2006, 2005 and 2004.

DESCRIPTION OF THE BUSINESS

Canadian Natural is a Canadian based senior independent energy company engaged in the acquisition, exploration, development, production, marketing and sale of crude oil, NGLs, natural gas and bitumen production. 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 Canadian Natural 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 presence 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, NGLs, light/medium crude oil, Pelican Lake crude oil, primary heavy crude oil and thermal heavy crude 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 42 per cent of 2006 production. Virtually all of the Company's natural gas and NGLs production is located in the Canadian provinces of Alberta and British Columbia and is marketed in Canada and the United States. Light/medium crude oil and NGLs, representing 26 per cent of 2006 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 crude oil operations in the Provinces of Alberta and Saskatchewan account for 27 per cent of 2006 production. Other heavy crude oil, which accounts for five per cent of 2006 production, is produced from the Pelican Lake area in north Alberta. This production, which has medium crude oil netback characteristics, is developed through a staged horizontal drilling program complimented by water flooding. Midstream assets, comprised of three crude oil pipelines and an electricity co-generation facility, provide cost effective infrastructure supporting the heavy and Pelican Lake crude oil operations. Canadian Natural expects its ownership of oil sands leases near Fort McMurray, Alberta to provide a basis for long-term synthetic crude oil production growth. The first three phases of the Horizon Project, which encompasses only a portion of these oil sands leases are expected to deliver approximately 37 years of synthetic crude oil production.

As a result of the Company's core undeveloped land base of 12.8 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, NATURAL GAS AND OIL SANDS PROPERTIES

Set forth below is a summary of the principal crude oil, natural gas and oil sands properties as at December 31, 2006. The information reflects the working interests owned by the Company.

<TABLE>
<CAPTION>

YEAR ENDED 2006 AVERAGE DAILY PRODUCTION RATES			DECEMBER 31, 2006	MAJOR INFRASTRUCTURE AS AT DECEMBER 31, 2006
REGION	CRUDE OIL & NGLs (mbbl)	NATURAL GAS (mmcf)	UNDEVELOPED ACREAGE (thousands)	BATTERIES/ COMPRESSORS & PLANTS/ PLATFORMS /FPSO
<S>	<C>	<C>	<C>	<C>
NORTH AMERICA				
Northeast B. C.	6.7	408	2,721	1/11/-/-
Northwest Alberta	15.0	454	1,750	-/14/-/-
Northern Plains	194.5	437	7,211	12/6/-/-
Southern Plains	10.5	165	870	-/3/-/-
Southeast Saskatchewan	8.4	3	117	-/-/-/-
Non - core regions	0.2	1	249	-/-/-/-
Horizon Oil Sands	-	-	116	-/-/-/-
INTERNATIONAL				
North Sea UK Sector	60.1	15	299	-/-/6/1
Offshore West Africa				
Cote d'Ivoire	36.7	9	55	-/-/-/2
Gabon	-	-	152	-/-/-/-
Non - core regions				
South Africa	-	-	4,002	-/-/-/-
TOTAL	332.1	1,492	17,542	13/34/6/3

</TABLE>

DRILLING ACTIVITY

Set forth below is a summary of the drilling activity, excluding stratigraphic test and service wells, of the Company for each of the last three fiscal years ending December 31, 2006 by geographic region:

<TABLE>
<CAPTION>
2006

NET EXPLORATORY			NET DEVELOPMENT		
PRODUCTIVE	DRY HOLES	TOTAL	PRODUCTIVE	DRY HOLES	TOTAL
<S>	<C>	<C>	<C>	<C>	<C>
CANADA					
17.2	5.6	22.8	158.9	14.1	173.0
Northeast B. C.					
17.7	9.5	27.2	149.6	14.6	164.2
Northwest Alberta					
104.1	28.2	132.3	598.5	36.1	634.6
Northern Plains					
31.8	8.4	40.2	78.6	1.0	79.6
Southern Plains					
-	-	-	72.7	2.0	74.7
Southeast Saskatchewan					
0.6	-	0.6	2.7	-	2.7
Non - core regions					
NORTH SEA UK SECTOR		-	-	-	7.4	-	7.4
OFFSHORE WEST AFRICA					
Cote d'Ivoire		-	-	-	4.1	-	4.1
TOTAL		171.4	51.7	223.1	1,072.5	67.8	1,140.3

2005

NET EXPLORATORY			NET DEVELOPMENT		
PRODUCTIVE	DRY HOLES	TOTAL	PRODUCTIVE	DRY HOLES	TOTAL
CANADA					
32.1	7.2	39.3	179.9	21.1	201.0
Northeast B. C.					
29.9	9.0	38.9	135.2	7.3	142.5
Northwest Alberta					
63.5	11.5	75.0	671.4	51.9	723.3
Northern Plains					
50.6	5.0	55.6	294.9	2.0	296.9
Southern Plains					
1.0	-	1.0	43.0	-	43.0
Southeast Saskatchewan					
-	-	-	0.3	-	0.3
Non - core regions					
NORTH SEA UK SECTOR		-	0.8	0.8	11.5	0.9	12.4
OFFSHORE WEST AFRICA					
Cote d'Ivoire		-	0.6	0.6	3.5	-	3.5
TOTAL		177.1	34.1	211.2	1,339.7	83.2	1,422.9

2004

NET EXPLORATORY			NET DEVELOPMENT		
PRODUCTIVE	DRY HOLES	TOTAL	PRODUCTIVE	DRY HOLES	TOTAL
CANADA					
23.8	6.2	30.0	146.8	14.4	161.2
Northeast B. C.					
42.8	7.6	50.4	100.4	3.9	104.3
Northwest Alberta					
116.6	26.6	143.2	333.8	23.2	357.0
Northern Plains					
18.5	7.0	25.5	209.9	4.0	213.9
Southern Plains					
-	-	-	12.5	-	12.5
Southeast Saskatchewan					
-	-	-	0.5	0.3	0.8
Non - core regions					
NORTH SEA UK SECTOR		-	2.0	2.0	9.2	-	9.2
OFFSHORE WEST AFRICA					
Cote d'Ivoire		-	0.7	0.7	2.3	-	2.3
TOTAL		201.7	50.1	251.8	815.4	45.8	861.2

</TABLE>

PRODUCING CRUDE OIL & NATURAL GAS WELLS

Set forth below is a summary of the number of gross and net wells within the Company that were producing or capable of producing as of December 31, 2006:

<TABLE>
<CAPTION>

	NATURAL GAS WELLS		CRUDE OIL WELLS		TOTAL WELLS	
	GROSS	NET	GROSS	NET	GROSS	NET
<S>	<C>	<C>	<C>	<C>	<C>	<C>
CANADA						
Northeast B. C.	1,548.0	1,305.5	243.0	203.5	1,791.0	1,509.0
Northwest Alberta	1,681.0	1,294.7	521.0	305.9	2,202.0	1,600.6
Northern Plains	4,022.0	3,233.4	5,705.0	5,204.6	9,727.0	8,438.0
Southern Plains	6,955.0	5,986.9	1,140.0	1,032.0	8,095.0	7,018.9
Southeast Saskatchewan	-	-	1,092.0	694.8	1,092.0	694.8
Non - core regions	316.0	118.6	665.0	202.1	981.0	320.7
UNITED STATES	4.0	0.5	4.0	0.7	8.0	1.2
NORTH SEA UK SECTOR	2.0	0.1	118.0	96.8	120.0	96.9
OFFSHORE WEST AFRICA						
Cote d'Ivoire	0.0	0.0	15.0	8.7	15.0	8.7
TOTAL	14,528.0	11,939.7	9,503.0	7,749.1	24,031.0	19,688.8

</TABLE>

All reserves data in the following property report is based on the applicable independent engineering report. See below "Conventional Crude Oil, NGLs and Natural Gas Reserves" and "Oil Sands Mining Disclosure".

NORTHEAST BRITISH COLUMBIA

[GRAPHIC OMITTED - MAP]

Significant geological variation extends throughout the productive reservoirs in region, producing light crude oil, NGLs and natural gas. The Company holds working interests ranging up to 100 per cent and averaging 74 per cent in 5,107,623 gross (3,721,424 net) acres of producing and undeveloped land in the region.

Crude oil reserves are found primarily in the Halfway formation, while natural gas and associated NGLs are found in numerous carbonate and sandstone formations at depths up to 4,500 vertical meters. The exploration strategy focuses on comprehensive evaluation through two-dimensional seismic, three-dimensional seismic and targeting economic prospects close to existing infrastructure. The region has a mix of low risk multi-zone targets, deep higher risk exploration plays and emerging unconventional natural gas plays including shale gas and CBM. The 2006 acquisition of ACC significantly increases the Company's asset base in Northeast British Columbia with the addition of the ACC properties in Adsett, Caribou and Ft. St. John West. The southern portion of this region encompasses the Company's BC Foothills assets; here natural gas is produced from the deep Mississippian and Triassic aged reservoirs in this highly deformed structural area. In 2006 the Company's assets in Monkman and Ojay were augmented by the assets previously owned by ACC in the area.

Natural gas production from the region averaged 408 mmcf/d in 2006 compared to the average of 434.4 mmcf/d in 2005. Crude oil and NGLs production was steady at 6,700 bbl/d in 2006, unchanged from an average of 6,700 bbl/d in 2005.

During 2005, the Company initiated a new exploration and development play that targets natural gas found in the shallow Notikewin formation in the Fort St. John area. Wells drilled into this formation generally produce at rates of up to 500 to 700 mmcf/d. In combination with the Company's extensive land base and the recently reduced royalty rates in British Columbia, this shallow gas drilling program will add to the Company's opportunities in this region. Development of this play continued in 2006 with the drilling of 45 wells at Ladyfern. Another shallow gas play was pursued in 2006 with the drilling of 50 Banff wells at Shekelie.

During 2006, the Company drilled 12.9 (2005 - 10.9) net crude oil wells, 163.2 (2005 - 201.1) net natural gas wells, 0.0 (2005 - 1.0) net stratigraphic/service wells and 19.7 (2005 - 28.3) net dry wells on its lands in this region for a total of 195.8 (2005 - 241.3) net wells. The Company held an average 86 per cent working interest in these wells.

NORTHWEST ALBERTA

[GRAPHIC OMITTED - MAP]

The Company holds working interests ranging up to 100 per cent and averaging 73 per cent in 3,537,210 gross (2,582,042 net) acres of producing and undeveloped land in the region located along the border of British Columbia and Alberta west of Edmonton.

The majority of the Company's initial holdings in the region were obtained through the 2002 acquisition of RAX; subsequent to 2002 the Company augmented these holdings with additional land purchases, acquisitions and in 2006 the purchase of the ACC assets. The ACC acquisition added two very prospective properties to this region, Wild River and Peace River Arch. The Wild River assets will provide a premium developed and undeveloped land base in the deep basin, multi-zone gas fairway and the Peace River Arch assets provides premium lands in a multi-zone region along with key infrastructure. Northwest Alberta provides exploration and exploitation opportunities in combination with an extensive 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 700 to 4,500 meters. The northern portion of this core region provides extensive multi-zone Cretaceous opportunities similar to the geology of the Company's Northern Plains core region. The Company is also pursuing development of a Doig shale gas play in this region. The southern portion provides exploration and development opportunities in the regionally extensive Cretaceous Cardium formation and in the deeper, tight gas formations throughout the region. The Cardium is a complex, tight natural gas reservoir where high productivity may be achieved due to greater matrix porosity or natural fracturing. Recent regulatory changes have improved the economics of multi-zone production by providing the opportunity to commingle multiple zones within a single wellbore. The south western portion of this region also contains significant Foothills assets with natural gas produced from the deep Mississippian and Triassic aged reservoirs. In 2006 Canadian Natural had significant success in this Foothills region with drilling successes at Copton, Dinosaur and Cabin Creek.

Natural gas production from the region averaged 454 mmcf/d in 2006 compared to an average of 403.4 mmcf/d in 2005. Crude oil and NGLs production increased to 15.0 thousand bbl/d in 2006 from 13.5 thousand bbl/d in 2005.

During 2006, the Company drilled 14.5 (2005-12.9) net crude oil wells, 152.8 (2005-152.4) net natural gas wells, 0.0 (2005 - 0.7) net stratigraphic/service wells, and 24.1 (2005-16.3) net dry wells on its lands in this region for a total of 191.4 (2005-182.3) net wells. The Company held an average 72 per cent working interest in these wells.

NORTHERN PLAINS

[GRAPHIC OMITTED - MAP]

The Company holds working interests ranging up to 100 per cent and averaging 83 per cent in 12,781,313 gross (10,711,563 net) acres of producing and undeveloped land in the region located just south of Edmonton north to Fort McMurray and from the Northwest Alberta area east to the border with Saskatchewan and extending into western Saskatchewan.

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, NGLs and light crude oil are also encountered at slightly greater 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 437 mmcf/d in 2006 compared to 419.2 mmcf/d in 2005. Crude oil and NGLs production from this region increased to 194.5 thousand bbl/d in 2006 from 181.8 thousand bbl/d in 2005. Production of natural gas was negatively impacted by the shut-in effective July 1, 2004 of approximately 11 mmcf/d in the Athabasca Wabiskaw-McMurray oil sands area pursuant to the decision of the Alberta Energy and Utilities Board.

In February 2004, the Company purchased the Petrovera Partnership which added additional properties in this region. Approximately one third of the total acquisition was sold to another independent producer. The properties that were retained further consolidated the Company's position in the area.

Natural gas in this region is produced from shallow, low-risk, multi-zone prospects and more recently from the Horseshoe Canyon coal bed methane ("CBM"). The Company targets low-risk exploration and development opportunities and plans to expand its commercial Horseshoe Canyon CBM project. During 2006, natural gas development drilling included 120.5 net wells and 48.0 net Horseshoe Canyon CBM locations. Evaluation of the potential for production of CBM from the Mannville coals commenced in 2006 with the drilling of three horizontal wells; these wells will be tested and produced to determine the economic viability of this play.

In the area near Lloydminster, Alberta, reserves of heavy crude 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 crude oil to the wellbore in this type of heavy crude oil reservoir comes from solution gas. The crude oil viscosity and the reservoir quality will determine the amount of crude oil produced from the reservoir, which will vary from 3 to 20 per cent of the original crude oil in place. A key component to maintaining profitability in the production of heavy crude oil is to be a low-cost producer. The Company continues to achieve low costs producing heavy crude oil by holding a dominant position that includes a significant land base and an extensive infrastructure of batteries and disposal facilities.

The Company's holdings in this region of primary heavy oil production are both the result of Crown land purchases and several acquisitions including major acquisitions from Sceptre Resources, Koch Exploration, Ranger Oil and Petrovera. 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 north to the Company operated Beartrap field during 2001 and to the Morgan field in 2006 enhancing development and reducing operating costs for the Company's extensive holdings in the area. This pipeline was capable of transporting 57 thousand bbl/d of hot, unblended crude oil to sales facilities at Hardisty, Alberta and in 2003 its capacity was expanded to handle up to 72 thousand bbl/d. 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. This transportation control enhances the Company's ability to control the full spectrum of costs associated with the development and marketing of its heavy crude oil. The ECHO Pipeline system permits the Company to transport approximately 80 per cent of its heavy crude oil to the international mainline liquids pipelines.

Production from the 100% owned Primrose and Wolf Lake Fields located near Bonnyville, Alberta involves processes that utilize steam to increase the recovery of the heavy (10(Degree)-11(Degree)API) crude oil. The two processes employed by the Company are cyclic steam stimulation and Steam Assisted Gravity Drainage ("SAGD"). Both recovery processes inject steam to heat the heavy crude oil deposits, reducing the oil viscosity and thereby improving its flow characteristics. There is also an infrastructure of gathering systems, a processing plant with a capacity of 80 thousand bbl/d of crude oil and a 50 per cent interest in a co-generation facility capable of producing 84 megawatts of electricity for the Company's use and sale into the Alberta power grid at pool prices. Since acquiring the assets from BP Amoco in 2000, the Company has successfully converted the field from low-pressure steaming to high-pressure steaming. This conversion resulted in a significant improvement in well productivity and in ultimate oil recovery. Canadian Natural drilled 58 high-pressure wells in 2004. In 2004, the Company started to proceed with its Primrose North expansion project, which was effectively completed in late 2005 with total capital expenditures of approximately $300 million incurred. The Primrose North expansion entails a remote steam generation facility and additional high pressure cyclic steam wells. First crude oil production from the expansion project began in January 2006. Also in 2004 the Company filed a public disclosure document for regulatory approval of its Primrose East project, a new facility located about 15 kilometers from its existing Primrose South steam plant and 25 kilometers from its Wolf Lake central processing facility. The development application for Primrose East was submitted to the Alberta Energy and Utilities Board in January 2006, with potential impacts associated with the use of bitumen as fuel being evaluated in the Environmental Impact Assessment. The Company received regulatory approval for the project in February, 2007 and construction will begin in 2007, with the first steam injection scheduled for first quarter 2009. A mature 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. In December 2006 Canadian Natural issued a Public Disclosure Document outlining our proposed development plan for the 30 thousand bbl/d Kirby In-Situ Oil Sands Project located approximately 85 km northeast of Lac La Biche. Regulatory applications for the project are expected to be submitted in late 2007.

In 2006 the Company undertook a Scoping Study to evaluate the construction of an upgrader to process the Company's Athabasca and Cold Lake thermal production. The study included evaluating the product alternatives, location, technology, gasification and integration with existing assets. The next steps in this process would include a Design Base Memorandum ("DBM") and Engineering Design Specifications ("EDS") which would be required to be completed prior to construction and sanctioning of the project by the Board of Directors of the Company. Based upon the results of the Scoping Study, which identified growing concerns relating to increased environmental costs for upgraders located in Canada, inflationary capital cost pressures and narrowing heavy oil differentials in North America, the Company has, at this point in time, deferred the DBM and EDS pending clarification on the cost of future environmental legislation and a more stable cost environment.

Included in the northern part of this region, approximately 200 miles north of Edmonton, are the Company's holdings at Pelican Lake. These assets produce crude oil from the Wabasca formation with gravities of 11(Degree)-17(Degree)

API. Production costs are low due to the absence of sand production, its associated disposal requirements and the gathering and pipeline facilities in place. 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 economic development of the large crude oil pool located on the lands. The Company holds and controls approximately 75 percent of the known crude oil pool in this area.

It is estimated this field contains approximately four billion barrels of original crude oil in place but is only expected to achieve less than a five percent average recovery factor using existing primary production on the Company's developed leases. Hence, in 2002 the Company embarked upon an Enhanced Oil Recovery ("EOR") scheme using an emulsion flood to increase the ultimate recoveries from the field. The experimental Pelican Lake emulsion flood showed that the recovery mechanism was very efficient; however, response time was slow. Due to the slow response time, the Company reverted to a waterflood scheme for this field. The waterflood provided initial production increases as expected and has shown positive waterflood response. To date approximately 11% of the field has been converted to waterflood. To further enhance the expected crude oil recovery from the waterflood, in the second quarter of 2005, the Company initiated a five well polymer flood pilot test. Performance of the polymer flood pilot test has been positive, with crude oil production rates from the three production wells increasing from approximately 60 bbl/d in 2005 to over 500 bbl/d by December 2006. These results have led to the commercial expansion of this EOR technology with 36 additional wells undergoing polymer flooding by year end 2006. Pelican Lake production averaged approximately 30 thousands bbl/d in 2006.

During 2006, the Company drilled 484.0 (2005 - 536.1) net crude oil wells, 218.6 (2005 - 198.9) net natural gas wells, 206.9 (2005 - 108.9) net stratigraphic/service wells, and 64.3 (2005 - 63.4) net dry wells for a total of 973.8 (2005 - 907.3) net wells. The Company's average working interest in these wells was 88.4 per cent.

SOUTHERN PLAINS AND SOUTHEAST SASKATCHEWAN

[GRAPHIC OMITTED - MAP]

In the Southern Plains area, the Company holds interests ranging up to 100 per cent and averaging 86 per cent in 2,147,945 gross (1,838,811 net) acres of producing and undeveloped land in the region, principally located south of the Northern Plains area to the United States border and extending into western Saskatchewan.

Reserves of natural gas, condensate and light 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 throughout the year. It is economic to drill shallow wells with reduced well spacings in this region despite having smaller overall reserves and lower productivity per well since they achieve a favourable rate of return on capital employed with low drilling costs and long life reserves. The Company's extensive shallow gas assets in this region have been augmented in 2006 as a result of the Company's development of the Senate shallow gas play in SW Saskatchewan and the purchase of the ACC Hatton assets in SW Saskatchewan. Other assets acquired from ACC in this region include the crude oil producing assets at Taber.

The Company maintains a large inventory of drillable locations on its land base in this region. This region is one of the more mature regions of the Western Canadian Sedimentary Basin and requires continual operational cost control through efficient utilization of existing facilities, flexible infrastructure design and consolidation of interests where appropriate.

The Company's share of production in the Southern Plains area averaged 10.5 thousand bbl/d of crude oil and NGLs compared to 10.7 thousand bbl/d in 2005. Natural gas production amounted to 165 mmcf/d in 2006 compared to the 155.4 mmcf/d averaged in 2005.

During 2006, the Company drilled a total of 6.2 (2005 - 9.0) net crude oil wells, 104.2 (2005 - 336.5) net natural gas wells, 0.0 (2005 - 1.7) net stratigraphic/service wells and 9.4 (2005 - 7.0) net dry wells in this region for a total of 119.8 (2005 - 354.2) net wells. The Company's average working interest in these wells was 57.3 per cent.

The Williston Basin is located in Southeast Saskatchewan with lands extending into Manitoba. This region 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 82 per cent in 220,266 gross (181,691 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. The Company's share of production in the Southeast Saskatchewan area averaged 8,400 bbl/d of crude oil and NGLs in 2006 compared to 8,800 bbl/d in 2005. Natural gas production averaged 3 mmcf/d in 2006 (2005 - 3.1 mmcf/d).

The Company drilled 72.7 (2005 - 43.0) net crude oil wells, 0.0 (2005 - 1.0) net natural gas well, 0.0 (2005 - 7.6) net stratigraphic/service wells and 2.0 (2005 - 0.0) net dry wells in this region in 2006, for a total of 74.7 (2005 - 51.6) net wells. The Company's average working interest in these wells is 86.9 per cent.

HORIZON OIL SANDS PROJECT

[GRAPHIC OMITTED - MAP]

Canadian Natural owns a 100 per cent working interest in its Athabasca Oil Sands leases in Northern Alberta, of which a portion (being lease 18) is subject to a 5 per cent net carried interest in the bitumen development. The Horizon Project is located on these leases, about 70 kilometers north of Fort McMurray. The project includes surface oil sands mining, bitumen extraction, bitumen upgrading to produce a 34 o API synthetic light crude oil ("SCO"), and associated infrastructure.

The project, which has two aspects; namely, bitumen production and bitumen upgrading to SCO, is designed as a phased development. Site clearing and pre-construction preparation activities commenced in 2004 and construction is planned to continue through 2011 or 2012. Phase 1 production is targeted to begin in the second half of 2008 at 110 thousand bbl/d of SCO. Subsequent expansion is expected to increase production to 232 thousand bbl/d of SCO. These targeted rates of production represent nominal design capacity. The Company is currently evaluating the opportunity to combine Phase 2 and Phase 3, for which certain major items were ordered in 2006 and certain major facility components had construction commence on them in 2006. Canadian Natural will seek to maximize resource recovery and overall production through ongoing optimization of operations. The phased approach provides the Company with improved cost and project controls in terms of labour and materials management and may mitigate any negative effects of growth on local infrastructure.

Canadian Natural filed an application for regulatory approval of the Horizon Project in June 2002. The application included a comprehensive environmental impact assessment and a social and economic assessment and was accompanied by public consultation. A federal-provincial regulatory Joint Review Panel (the "Panel") examined the project in a public hearing in September 2003. The Panel issued its decision report in January 2004, finding that the Horizon Project is in the public interest. An Alberta Order-in-Council approval was received in February 2004. Subsequently, key approvals were received from Alberta Environment under the ENVIRONMENTAL PROTECTION ACT and WATER ACT, and from Fisheries and Oceans Canada under the FISHERIES ACT.

The Company is concurrently working with legislators and regulators on the design of new greenhouse gas emission laws and regulations and is pursuing an integrated emissions reduction strategy, to ensure the Company is able to comply with existing and future emission reductions requirements. The Company continues to develop strategies that will enable it to deal with the risks and opportunities associated with new climate change policies. In addition, the Company is working with relevant parties to ensure that new policies encourage

innovation, energy efficiency, targeted research and development while not impacting competitiveness.

The Company continues to work with Canadian Federal and Provincial governments on the regulatory framework for greenhouse gases for larger emitters. The Company is actively promoting a harmonized regulatory framework between the two levels of government. Both levels of government have indicated that existing legislation will be amended in 2007 to create further requirements for reporting emissions, facility-based emission intensity targets and regulatory compliance. Compliance with emission intensity targets is expected for 2008 and possibly a part of 2007 for larger facilities in Alberta.

Canadian Natural used a structured system called Front End Loading to ensure that project definition is adequate and complete before proceeding with implementation. This system is used successfully worldwide to mitigate risk on large capital projects in a variety of industries. The process is well documented at every step and is audited by an independent organization. In June 2002, the Company commenced the Design Basis Memorandum ("DBM"), which is the second of three front-end engineering phases. The DBM was completed for all project components in February 2004. In August 2003, the Company commenced work on the third and final front-end engineering phase for Phase 1, completing the work in December 2004. The products of this phase include a detailed project execution plan, Engineering Design Specifications ("EDS") and a detailed cost estimate (plus or minus 10%). The EDS provided sufficient definition for a lump sum inquiry for the Detailed Engineering, Procurement and Construction of the various project components. With this information a "cost certainty" estimate was developed as a basis for project sanction by the Board of Directors, which was given in February 2005, authorizing management to proceed with Phase 1 of the Horizon Project. The Company is now developing various cost effective options for execution of additional construction on Phase 2 and Phase 3 of the Horizon Project taking into account the current business environment.

The Horizon Project is designed to use proven technology and will seek to take advantage of technology improvements that advance environmental performance, enhance the work environment for workers, increase reliability and production and reduce capital and production costs. By the end of 2004 the Company had acquired all key technologies for the project. At year end 2006, Canadian Natural's Horizon Project team, consisted of 705 permanent employees and several interim contractors to fill 79% of the projected team position requirements.

Horizon Project Phase 1 construction costs were approximately $2.77 billion in 2006 and cumulative expenditures were approximately $4.0 billion through the end of 2006. Construction costs for 2007 are budgeted to range from $2.4 billion to $2.8 billion reflecting major expenditures for detailed engineering, procurement and construction of Phase 1 of the Project. In addition, capital expenditures of $109 million are budgeted for Phase 2 and Phase 3 development and construction in 2007. These expenditures are direct project costs only and do not include capitalized interest, stock based compensation, lease evaluation, or Front End Engineering.

During 2006, the Company drilled 163.0 (2005 - 126.0) stratigraphic test wells to further delineate the ore body and confirm resource quality and quantity.

UNITED KINGDOM NORTH SEA

[GRAPHIC OMITTED - MAPS]

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 367,251 gross (296,658 net) acres of producing and non-producing properties in the UK sector of the North Sea. In 2006, the Company produced from 16 crude oil fields.

The northerly fields are centered around the Ninian Field where the Company has an 87.1 per cent working interest. The central processing facility is connected to other fields including the Columba Terraces and Lyell Fields where the Company operates with working interests of 91.6 per cent to 100 per cent. In 2002, the Company completed property acquisitions in the northern North Sea that increased its ownership levels in the Ninian, Murchison, Lyell and Columba Terraces 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. In 2003, the Company further consolidated its ownership with the acquisition of additional working interests in the Ninian and Columba Fields, associated facilities and adjacent exploration acreage.

In the central portion of the North Sea, in 2003, the Company increased its equity in the Banff Field to 87.6 per cent and took over as operator. The Company also owns a 45.7 per cent operated working interest in the Kyle Field. Beginning in the third quarter of 2005, all production for the Kyle Field was processed through the Banff FPSO facilities. The consolidation of these production facilities resulted in lower combined production costs from these fields.

In 2004, the Company acquired 100 per cent working interest in T-block (comprising the Tiffany, Toni and Thelma Fields) and 68.7 per cent to 75.3 per cent interests in the Fields known as B-block (comprising Balmoral, Stirling and Glamis). The Company took over as operator of these fields.

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 field owners for the processing of

crude oil and natural gas through some of the processing facilities. Opportunities for further long-reach well development on adjacent fields are provided by the existing processing facilities.

During 2006, production to the Company from this region averaged 60.1 thousand bbl/d of crude oil (2005 - 68.6 thousand bbl/d). Natural gas production averaged 15.0 mmcf/d in 2006 (2005 - 18.4 mmcf/d).

During 2006 the Company drilled 7.4 (2005 - 11.5) net crude oil wells, 1.8 (2005 - 0.9) net stratigraphic/service wells and 0.0 (2005 - 1.7) net dry wells in this region for a total of 9.2 (2005 - 14.1) net wells. The Company's average working interest in these wells is 92.0 per cent.

OFFSHORE WEST AFRICA

[GRAPHIC OMITTED - MAP]

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. As a result, the Company owned working interests ranging from 50 per cent to 100 per cent in 1,596,013 gross (887,657 net) acres in those countries. During 2005, the Company either relinquished or sold all of its interests in offshore Angola. In 2006, certain exploration acreage in Cote d'Ivoire was also relinquished.

In 2005, the Company acquired the permit to develop the Olowi Field, offshore Gabon, West Africa, consisting of 151,818 acres. The Company has a 90 per cent interest in a production sharing agreement for the block.

The Company also has a 100 per cent interest in 4,001,574 acres offshore South Africa where it is shooting and evaluating seismic data and undertaking environmental studies.

COTE D'IVOIRE

The Company owns interests in two exploration licences offshore Cote d'Ivoire comprising 55,408 net acres. During 2001, the Company increased its interest in Block CI-26, which contains the Espoir Field, to a 58.7 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 approximately 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 first phase of development of East Espoir, which included the drilling of both producing and water injection wells from a single wellhead tower, was completed in 2003. The construction and installation of a new wellhead tower for the West Espoir part of the field were completed in 2005. Due to a successful infill drilling program completed at East Espoir in early 2006 the Company achieved 24.0 thousand bbl/d of net production from the Field. Following the infill drilling at East Espoir, development drilling commenced at West Espoir with first oil from the Field delivered July, 2006.

Crude oil from the East and West Espoir Fields is produced to an FPSO with the associated natural gas delivered onshore through a subsea pipeline for local power generation. In 2003, the Company drilled a satellite pool, Acajou, which encountered a reservoir with good quality and hydrocarbons. The extent of this accumulation was further appraised by a well drilled in 2004 which did not encounter commercial hydrocarbons.

The unsuccessful Zaizou exploration well was drilled in block CI-40 in 2005.

In the first quarter of 2001, the Company drilled and tested the Baobab exploration prospect, identified on Block CI-40, eight kilometers south of the Espoir facilities, in which the Company has a 58 per cent interest. 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. The Company established a field development plan, which was approved by the Government of Cote d'Ivoire in December 2002. In 2003, the Company awarded four major contracts for the development of the Baobab Field. These contracts included the deep water drilling rig to drill 8 producing and 3 water injection wells, the FPSO, supplies for the subsea equipment and the supply of pipeline and risers, and installation of the subsea infrastructure. Development commenced in late 2003 and first oil was achieved in August 2005 producing at approximately 30 thousand bbl/d net to Canadian Natural from 4 wells. Upon completion of drilling additional wells in 2006, production levels increased as expected. Subsequent problems with the control of sand and solids production lead to five of the ten production wells being shut in by the end of the year, resulting in approximately 15.5 thousand bbl/d of net production capacity being shut in. The Company does not plan to complete these wells until such time as a deepwater rig can be secured on commercially acceptable terms.

To date 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 a nearby country if the situation warrants such a move.

During 2006, Company production averaged 36.7 thousand bbl/d of crude oil (2005 - - 22.9 thousand bbl/d). Company natural gas production amounted to 9.5 mmcf/d in 2006 (2005 - 4.2 mmcf/d).

In 2006, the Company drilled 4.1 (2005 - 3.5) net crude oil wells, 1.7 (2005 - 1.1) net stratigraphic/service wells and 0.0 (2005 - 0.6) net dry wells for a total of 5.8 (2005 - 5.2) net wells. The Company's average working interest in these wells is 58.7 per cent.

ANGOLA

During 2002, the Company was awarded operatorship and a 50 per cent working interest in exploration Block 16 situated offshore The People's Republic of Angola. 3-D seismic data was obtained over the entire Block 16 before obtaining title and identified two targets: Omba in the north and Zenza in the west central portion of the Block. The Company had a two well commitment over a four year time frame expiring August 31, 2006. The first well, Zenza-1, was drilled

during the fourth quarter of 2003 and was not considered commercial. Following further evaluation of seismic data and the well results during 2004 and even though additional review of seismic and geological data on Block 16 indicated that significant upside remained a possibility, the risk level associated with Block 16 was outside the normal operating parameters of the Company. As a result, the Company entered into an agreement to dispose of its interest in Block 16 effective December 31, 2005. As of the sale of Block 16, the Company no longer has any holdings in Angola.

GABON

[GRAPHIC OMITTED - MAP]

The Company acquired permit No. G4-187 comprising a 90 per cent operating interest in the production sharing agreement for the block containing the Olowi Field, located about 20 kilometers from the Gabonese coast and in 30 meters water depth. Olowi has been delineated by the drilling of 15 wells on the block. Based on estimates from the previous owner it was estimated that the properties held 500 million barrels of original oil in place and 1 trillion cubic feet of original gas in place. Subsequent to acquiring the assets and all technical data, the Company performed a detailed analysis on the geological, geophysical and engineering data and has reestimated the pool size. The Company's internal estimates for Olowi are that the pool contains up to 215 million barrels of 34(0) API light crude original oil in place, with an underlying gas cap containing up to 590 billion cubic feet of original gas in place. A development plan, comprising an FPSO and four drilling towers, was filed with the Gabonese Government in late 2005 and approved in February 2006. The development plan for the pool commenced in late 2006 and first production is targeted for late 2008.

B. CONVENTIONAL CRUDE OIL, NGL, AND NATURAL GAS RESERVES

For the year ended December 31, 2006, Canadian Natural retained qualified independent reserve evaluators, Sproule Associates Limited ("Sproule") and Ryder Scott Company ("Ryder Scott"), to evaluate 100% of the Company's conventional proved as well as proved and probable crude oil, NGL and natural gas reserves and prepare Evaluation Reports on these reserves. Sproule evaluated the Company's North America conventional assets and Ryder Scott evaluated its international conventional assets. The Company has been granted an exemption from the National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada. This exemption allows the Company to substitute United States Securities and Exchange Commission ("SEC") requirements for certain disclosures required under NI 51-101. There are two principal differences between the two standards (i) the requirement under NI 51-101 to disclose both proved and proved and probable reserves, as well as the related net present value of future net revenues using forecast prices and costs; and, (ii) the definition of proved reserves used by the SEC to that of NI 51-101. However with respect to the definition of proved reserves, as discussed in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), the standards that NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs should not be material.

The Company has disclosed proved conventional reserves and the Standardized Measure of discounted future net cash flows using constant prices and costs as mandated by the SEC in the supplemental oil and gas information section of its annual report. The Company has also elected to provide the net present value of these same conventional proved reserves as well as the conventional proved and probable reserves and the net present value of these reserves under the same parameters as additional voluntary information. In addition to the constant price and cost scenario, the Company has also elected to provide both conventional proved and conventional proved and probable reserves, as well as the net present value of these reserves, using forecast prices and costs as voluntary additional information.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of Sproule and Ryder Scott to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and net present value of remaining conventional crude oil, NGL and natural gas reserves.

The following tables summarize the evaluations of conventional reserves and estimated net present values of these reserves at December 31, 2006.

THE ESTIMATED NET PRESENT VALUES OF RESERVES 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 ESTIMATED FUTURE NET REVENUES DERIVED FROM THE ASSETS ARE PREPARED PRIOR TO CONSIDERATION OF INCOME TAXES AND EXISTING ASSET ABANDONMENT LIABILITIES. ONLY FUTURE DEVELOPMENT COSTS AND ASSOCIATED FUTURE MATERIAL WELL ABANDONMENT LIABILITIES HAVE BEEN APPLIED. 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 FORECAST CASES WILL BE ATTAINED AND VARIANCES COULD BE SUBSTANTIAL.

<TABLE>
<CAPTION>
NET CONVENTIONAL CRUDE OIL, NGL AND NATURAL GAS RESERVES (NET OF ROYALTIES)

Constant Prices and Costs			
Crude Oil & NGLs (mmbbl)		Natural Gas (bcf)	
Total Proved Reserves	Total Proved and Probable Reserves	Total Proved Reserves	Total Proved and Probable Reserves
<S>	<C>	<C>	<C>
NORTH AMERICA			
Canada	887	1,502	3,703	4,855
United States	-	-	2	2
INTERNATIONAL			
United Kingdom	299	422	37	93
Cote d'Ivoire	115	173	56	99
Gabon	15	22	-	-
TOTAL	1,316	2,119	3,798	5,049

</TABLE>

<TABLE>
<CAPTION>
CONVENTIONAL CRUDE OIL, NGL AND NATURAL GAS RESERVES

Constant Prices and Costs			
Crude Oil & NGLs (mmbbl)		Natural Gas (bcf)	
Company Gross	Net	Company Gross	Net
<S>	<C>	<C>	<C>
Proved developed reserves	779	697	3,619	2,963
Proved undeveloped reserves	708	619	994	835
TOTAL PROVED RESERVES	1,487	1,316	4,613	3,798
TOTAL PROVED AND PROBABLE RESERVES	2,397	2,119	6,112	5,049

<CAPTION>
ESTIMATED NET PRESENT VALUES

($ millions)	Constant Prices and Costs		
Undiscounted	Discounted at		
10%	15%	20%	
<S>	<C>	<C>	<C>
Proved developed reserves	31,286	20,028	17,296	15,321
Proved undeveloped reserves	17,974	7,469	5,247	3,787
TOTAL PROVED RESERVES	49,260	27,497	22,543	19,108
TOTAL PROVED AND PROBABLE RESERVES	75,787	37,291	29,350	24,102

</TABLE>

<TABLE>
<CAPTION>
CONVENTIONAL CRUDE OIL, NGL AND NATURAL GAS RESERVES

Forecast Prices and Costs

Crude Oil & NGLs (mmbbl)		Natural Gas (bcf)	
Company Gross	Net	Company Gross	Net
<S>	<C>	<C>	<C>
Proved developed reserves	771	698	3,643	2,982
Proved undeveloped reserves	706	633	994	831
TOTAL PROVED RESERVES	1,477	1,331	4,637	3,813
TOTAL PROVED AND PROBABLE RESERVES	2,540	2,294	6,141	5,067

ESTIMATED NET PRESENT VALUES

($ millions)	Forecast Prices and Costs			
Undiscounted	Discounted at			
	10%	15%	20%	
Proved developed reserves	33,483	21,734	18,975	16,973
Proved undeveloped reserves	17,446	7,410	5,267	3,856
TOTAL PROVED RESERVES	50,929	29,144	24,242	20,829
TOTAL PROVED AND PROBABLE RESERVES	78,155	38,896	30,883	25,604

</TABLE>

NOTES

1. "Company Gross" reserves means the total working interest share of remaining recoverable reserves owned by the Company before consideration of royalties.

2. "Net" reserves mean the Company's gross reserves less all royalties payable to others plus royalties receivable from others.

3. "Proved developed" reserves were evaluated using SEC standards and can be expected to be recovered through existing wells with existing equipment and operating methods. SEC standards require that these be evaluated using year-end constant prices and costs and be disclosed net of royalties. The Company has also provided these reserves using forecast prices and costs as well as before royalties and their associated net present values as additional voluntary information.

4. "Proved undeveloped" reserves were evaluated using SEC standards and 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. SEC standards require that these be evaluated using year-end constant prices and costs and be disclosed net of royalties. The Company has also provided these reserves using forecast prices and costs as well as before royalties and their associated net present values as additional voluntary information.

5. "Proved" reserves were evaluated using SEC standards and are those quantities of crude oil, natural gas and NGLs, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. SEC standards require that these be evaluated using year-end constant prices and costs and be disclosed net of royalties. The Company has also provided these reserves using forecast prices and costs as well as before royalties and their associated net present values as additional voluntary information.

6. "Total Proved and Probable" reserves were evaluated using the COGEH standards of NI 51-101 and are those reserves where there is at least a 50 per cent probability that the quantities actually recovered will equal or exceed the stated values. The Company has elected to disclose proved plus probable reserves using both constant prices and costs as well as forecast prices and costs and has disclosed these before and net of royalties and their associated net present values. The calculation of a probable reserves and value component by subtracting the proved reserves from the proved plus probable reserves may be subject to immaterial error

due to the different standards applied in the determination of each value.

7. Canadian securities legislation and policies permit the disclosure, of probable reserves which may not be disclosed in reports filed with the SEC by United States companies. 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.

8. All values are shown in Canadian dollars.

9. The constant price and cost case assumes that prices in effect at year-end 2006 adjusted for quality and transportation as well as the 2006 costs are held constant over life. 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 been held constant at the 2007 values shown below. In addition, operating and capital costs have not been increased on an inflationary basis.

The crude oil and natural gas constant prices used in the Evaluation Reports are as follows (based on a foreign exchange rate of US$0.860/C$1.00):

<TABLE>
<CAPTION>

NATURAL GAS			CRUDE OIL & NGLs						
Average Price	Henry Hub Louisiana	AECO	Company Huntingdon/ Sumas	Average Price	WTI @ Cushing(i)	Hardisty 12(degree)	Edmonton Heavy API	North Par(ii)	Sea Brent
YEAR	C$/MCF	US$/MMBTU	C$/MMBTU	C$/MMBTU	C$/BBL	C$/BBL	US$/BBL	C$/BBL	C$/BBL	US$/BBL
<S>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>
2007	6.07	5.52	6.13	6.52	51.11	61.05	41.94	67.59	58.93	

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

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

10. The forecast 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 and transportation. Reference prices and costs are escalated at 1.5 per cent per year. Future crude oil, NGLs and natural gas price forecasts were based on Sproule's December 31, 2006 crude oil, NGLs and natural gas pricing model. The Company's weighted average crude oil and NGLs price and the weighted average natural gas price in 2006 were $51.11 per barrel and $6.07 per mcf respectively, before adjustments due to hedging. The crude oil and natural gas forecast prices used in the Evaluation Reports are as follows:
<TABLE>
<CAPTION>

NATURAL GAS			CRUDE OIL & NGLs						
Average Price	Henry Hub Louisiana	AECO	Company Huntingdon/ Sumas	Average Price	WTI @ Cushing(i)	Hardisty 12(degree)	Edmonton Heavy API	North Par(ii)	Sea Brent
YEAR	C$/MCF	US$/MMBTU	C$/MMBTU	C$/MMBTU	C$/BBL	C$/BBL	US$/BBL	C$/BBL	C$/BBL	US$/BBL
<S>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>
2007	7.57	7.85	7.72	7.48	53.95	65.73	42.98	74.10	63.73	
2008	8.45	8.39	8.59	8.45	56.07	68.82	45.02	77.62	66.78	
2009	7.58	7.65	7.74	7.60	52.36	62.42	40.74	70.25	60.34	
2010	7.35	7.48	7.55	7.41	48.60	58.37	38.03	65.56	56.24	
2011	7.49	7.63	7.72	7.58	45.62	55.20	35.90	61.90	53.04	
2012	7.64	7.75	7.85	7.71	47.26	56.31	36.63	63.15	54.10	
2013	7.80	7.86	7.99	7.85	47.45	57.43	37.36	64.42	55.18	
2014	7.97	7.98	8.12	7.98	48.75	58.58	38.12	65.72	56.29	
2015	8.13	8.10	8.26	8.12	49.55	59.75	38.88	67.04	57.41	
2016	8.27	8.22	8.40	8.26	48.95	60.95	39.67	68.39	58.56	
2017	8.43	8.34	8.54	8.40	50.25	62.17	40.46	69.76	59.73	

</TABLE>
(i) Foreign exchange rate used was US$0.870/C$1.00 throughout the forecast

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

12. The estimated total development capital costs net to the Company necessary to achieve the estimated future net "proved" and "proved and probable" production revenues are:

<TABLE>
<CAPTION>

PROVED		PROVED AND PROBABLE	
FORECAST PRICE CASE ($ millions)	CONSTANT PRICE CASE ($ millions)	FORECAST PRICE CASE ($ millions)	CONSTANT PRICE CASE
<S>	<C>	<C>	<C>	<C>
2007	1,781	1,783	2,138	2,097
2008	1,555	1,615	2,275	2,040
2009	1,819	1,718	2,561	2,054
2010	915	841	2,096	1,479
2011	838	745	1,764	1,294
2012	420	370	630	549
2013	281	251	601	510
2014	344	299	709	603
2015	197	172	602	500
2016	193	168	418	341
2017	115	102	346	220
2018	215	180	424	332
Thereafter	1,143	919	2,317	1,694

</TABLE>

13. The Evaluation Reports involved data supplied by the Company with respect to quality, heating value and transportation adjustments, interests owned, royalties payable, operating costs and contractual commitments. This data was found by Sproule and Ryder Scott to be reasonable and no field inspection was conducted.

A report on conventional reserves data by Sproule and Ryder Scott and a report on oil sands mining reserves data by GLJ are provided in Schedule "A" to this Annual Information Form. A report by the Company's management and directors on crude oil and natural gas disclosure is provided in Schedule "B" to this Annual Information Form. The Company does not file estimates of its total crude oil and natural gas reserves with any U. S. agency or federal authority other than the SEC.

C. RECONCILIATION OF CHANGES IN NET CONVENTIONAL RESERVES

The following table summarizes the changes during the past year in reserves after deduction of royalties payable to others and using constant prices and costs:

<TABLE>
<CAPTION>

Crude Oil & NGLs (mmbbl)				Natural Gas (bcf)			
Offshore North America	North Sea	West Africa	Total	Offshore North America	North Sea	West Africa	Total
<S>	<C>	<C>	<C>	<C>	<C>	<C>	<C>
PROVED RESERVES							
RESERVES, DECEMBER 31, 2004	648	303	115	1,066	2,591	27	72	2,690
Extensions & Discoveries	98	-	-	98	506	-	-	506
Infill Drilling	3	3	2	8	22	-	-	22
Improved Recovery	-	-	-	-	8	-	-	8
Property purchases	-	-	15	15	6	-	-	6
Property disposals	(3)	-	-	(3)	(23)	-	-	(23)
Production	(70)	(25)	(8)	(103)	(411)	(7)	(1)	(419)
Revisions of prior estimates	18	9	10	37	42	9	1	52
RESERVES, DECEMBER 31, 2005	694	290	134	1,118	2,741	29	72	2,842
Extensions & Discoveries	53	3	-	56	250	-	-	250
Infill Drilling	190	14	-	204	71	-	-	71
Improved Recovery	-	12	-	12	3	-	-	3
Property purchases	26	-	-	26	1,111	-	-	1,111
Property disposals	-	-	-	-	(1)	-	-	(1)
Production	(75)	(22)	(13)	(110)	(433)	(5)	(3)	(441)
Revisions of prior estimates	(1)	2	9	10	(37)	13	(13)	(37)
RESERVES, DECEMBER 31, 2006	887	299	130	1,316	3,705	37	56	3,798
PROVED AND PROBABLE RESERVES							
RESERVES, DECEMBER 31, 2004	926	415	196	1,537	3,319	57	90	3,466
Extensions & Discoveries	200	-	-	200	645	-	-	645
Infill Drilling	3	5	6	14	23	-	1	24
Improved Recovery	-	-	-	-	14	-	-	14
Property purchases	-	-	17	17	8	-	-	8
Property disposals	(4)	-	-	(4)	(30)	-	-	(30)
Production	(70)	(25)	(8)	(103)	(411)	(7)	(1)	(419)
Revisions of prior estimates	(20)	22	(5)	(3)	(20)	19	20	19
RESERVES, DECEMBER 31, 2005	1,035	417	206	1,658	3,548	69	110	3,727
Extensions & Discoveries	128	3	-	131	307	-	-	307
Infill Drilling	384	17	-	401	95	-	-	95
Improved Recovery	-	12	-	12	4	-	-	4
Property purchases	34	-	-	34	1,466	-	-	1,466
Property disposals	-	-	-	-	(1)	-	-	(1)
Production	(75)	(22)	(13)	(110)	(433)	(5)	(3)	(441)
Revisions of prior estimates	(4)	(5)	2	(7)	(129)	29	(8)	(108)
RESERVES, DECEMBER 31, 2006	1,502	422	195	2,119	4,857	93	99	5,049

</TABLE>

Information on the Company's conventional crude oil, NGLs and natural gas reserves is provided in accordance with United States FAS 69, "Disclosures About Oil and Gas Producing Activities" in the Company's Form 40-F filed with the SEC and in the Company's 2006 Annual Report under "Supplementary Oil and Gas Information" on pages 99 to 103 and is incorporated herein by reference.

D. OIL SANDS MINING DISCLOSURE

INTRODUCTION

Canadian Natural holds a 100 per cent working interest in its Athabasca Oil Sands leases in Northern Alberta, of which a portion (being lease 18), is subject to a 5 per cent net carried interest in the bitumen development. The Horizon Project was initiated in 2000 to evaluate the potential for mining and processing the oil sands on these leases.

The Horizon Project is located in northeastern Alberta approximately 70 kilometers north of Fort McMurray in Townships 96 and 97, Ranges 11, 12 and 13, west of the 4th Meridian. The project site is accessible by a private road as well as a private airstrip. Figure 1 shows the location of the Horizon Project within Alberta, Canada and within the region. The leases being developed for the Horizon Project are 18, 25, 10, 19 and 20. Canadian Natural's development plan for the Horizon Project is to produce 232,000 barrels of synthetic crude oil per day. The project production schedule has been developed such that production rates are increased over three phases. Synthetic crude oil production is planned for the second half of 2008 at 110 thousand bbl/d and is targeted to to reach 232 thousand bbl/d with future expansion. Mining of the oil sands will be done using conventional truck and shovel technology. The ore is then processed through extraction and froth treatment to produce bitumen, which is upgraded on-site into synthetic crude oil. The synthetic crude oil is transported from the site by pipeline to the Edmonton area for distribution. An on-site cogeneration plant provides power and steam for the operation.

An independent qualified reserves evaluator, GLJ Petroleum Consultants ("GLJ"), was retained to evaluate 100 per cent of the first three phases of the Horizon Project's development plan. GLJ's Evaluation Report indicates that the gross lease proved and probable reserves associated with the Horizon Project are 3.0 billion barrels of synthetic crude oil with a production life of 37 years.

Since 1999, Canadian Natural has acquired over 46,000 hectares, comprising 11 leases in the Fort McMurray area.

FIGURE 1 - LOCATION OF THE HORIZON OIL SANDS PROJECT

[GRAPHIC OMITTED - MAPS]

TABLE 1 - CANADIAN NATURAL ATHABASCA REGION OIL SAND LEASES

SHORT LEASE NAME	OFFICIAL LEASE NUMBER	LEASE EXPIRY DATE(1)	AREA IN HECTARES
Lease 18 Producing(2)	727912T18	Continued	19,988
Lease 10	7400120010	December 14, 2015	3,840
Lease 25	7401050025	May 17, 2016	1,536
Lease 11	7400120011	December 14, 2015	518
Lease 12	7400120012	December 14, 2015	9,216
Lease 13	7400120013	December 14, 2015	69
Lease 15	7400120015	December 14, 2015	1,536
Lease 19	7402050019	May 30, 2017	5,120
Lease 20	7402050020	May 30, 2017	768
Lease 6	7597050T06	May 6, 2012	2,584
Lease 7	7597050T07	May 6, 2012	1,144

(1) The Company can apply for an extension of the leases past the expiry date.
(2) Pursuant to section 14 of the Oil Sands Tenure Regulation.

Lease 18, the main oil sand lease for the Horizon Project, has a gradual topographic slope from west to east. To the west, the topography begins to rise into the Birch Mountains and reaches an elevation of 485 meters above sea level in the northwest corner of the lease. To the east, the elevation drops sharply at the Athabasca River escarpment to 230 meters above sea level along the river. The Tar and Calumet Rivers flow through the lease.

PROJECT DEVELOPMENT

On June 28, 2002, Pursuant to Sections 10 and 11 of the Oil Sands Conservation Act, Canadian Natural filed Application No. 1273113 for approval for an oil sands mine, a bitumen extraction plant, a bitumen upgrader and associated facilities for the proposed Horizon Project. As part of the application to the Alberta Energy and Utilities Board ("EUB"), the Company also submitted an Environmental Impact Assessment ("EIA") report to the Director of the Regulatory Assurance Division, Alberta Environment, pursuant to the Environmental Protection Enhancement Act ("EPEA"). On June 26, 2003, the Federal Minister of Fisheries and Oceans referred the EIA of the project to a review panel charged with fulfilling the review as required by both the Canadian Environmental Assessment Act ("CEAA") and the Energy Resources Conservation Act ("ERCA"). A public hearing was held in Fort McMurray, Alberta on September 15-19, 22-26 and 29, 2003. The application and hearing provided significant background detail on the geology, mine planning and development scheme and formed the basis for the approval from the EUB in February 2004 and Alberta Environment ("AENV") under the Environmental Protection and Enhancement Act, in April 2004.

The following are the primary regulatory applications and approvals for the Horizon Project, which contain information pertaining to the project of a material engineering, geologic or metallurgic nature:

1. Application for Approval of Horizon Oil Sands Project submitted in June 2002 to the EUB (Application No.1273113) and AENV (Application No. 001-149968) (available at the EUB library, 640 5th Ave. SW, Calgary, Alberta - Tel: (403) 297-8311).

2. Supplemental Information for the Horizon Oil Sands Project (Application No. 1273113 and Application No. 001-149968) submitted in March 2003 to the EUB and AENV) (available at the EUB library, 640 5th Ave. SW, Calgary, Alberta - Tel: (403) 297-8311).

3. Horizon Oil Sands Project Decision 2004-005 by a joint panel review established by the EUB and the Government of Canada dated January 27, 2004 (available online at www.eub.gov.ab.ca).

4. Horizon Oil Sands Project Order in Council Authorization 26/2004 by the Province of Alberta dated February 4, 2004 (available at the EUB library, 640 5th Ave. SW, Calgary, Alberta - Tel: (403) 297-8311).

5. Horizon Oil Sands Project Approval No. 9752 by the EUB dated February 10, 2004 (available at the EUB library, 640 5th Ave. SW, Calgary, Alberta - Tel: (403) 297-8311).

6. Horizon Oil Sands Project Environmental Protection and Enhancement Act Approval No. 149968-00-01 from AENV dated April 6, 2004 (available online at WWW.GOV.AB.CA/ENV/WATER/APPROVALVIEWER.HTML search parameter - Approval No. 149968-00-01).

7. Horizon Oil Sands Project Water Act Approval No. 00201931-00-00 from AENV dated April 6, 2004 (available online at WWW.GOV.AB.CA/ENV/WATER/APPROVALVIEWER.HTML search parameter - Approval No. 149968-00-01).

As of year-end 2006, key development achievements associated with the Horizon Project were as follows:

- Phase 1 is 57 per cent complete.
- Mine overburden has removed 25.1 million bank cubic meters of material.
- Majority of foundations are complete.
- Main Piperack on site and set.
- Coke drums transported and erected.
- Hydrotreating reactors erected.

REGIONAL AND PROJECT GEOLOGY

In the area of the Horizon Project, the oil sands resource is found within the Cretaceous McMurray Formation. The McMurray Formation is comprised of a sequence of uncemented quartz sands and associated shales that reside above the unconformity with the underlying Upper Devonian carbonates (limestone) of the Waterways Formation. The general stratigraphy of the Horizon Project is shown in Figure 2.

The McMurray Formation was formed by the infilling of a broad northwest trending depression in the exposed Devonian limestone landscape by mostly non-marine and estuarine sediments about 115 million years ago. The deposition of these terrestrial derived sediments ended when the Boreal Sea transgressed the entire region, ushering in marine conditions that formed the Clearwater Formation shales and glauconitic Wabiskaw member. This interplay between rising sea level and sediment transport from the northeast gave rise to various depositional environments (fluvial, estuarine, and marine). The entire McMurray/Clearwater succession was (most recently about 10,000 years ago) covered by unconsolidated sands, silts, and clays (glacial drift) deposited by glaciers as they melted and receded from the region at the end of the last ice age.

The McMurray Formation at the site of the Horizon Project is subdivided into three informal members: lower, middle, and upper. These informal divisions correspond to changes in the depositional environments within the McMurray from predominantly fluvial to tidal/estuarine through to tidal/marine conditions. Most of the Horizon Project's oil sands resource is found within the lower and middle McMurray.

The lower McMurray, where present, is comprised of predominantly fluvial channel deposits. The lower McMurray occupies lows on the Devonian (Paleozoic) surface resulting in the thickest McMurray intervals. Clean sands in these fluvial channels result in excellent quality ore. Flood plain deposits of significant thickness are found in the upper portions of the lower McMurray and are typically removed as waste. In the deepest portions of the mine area, the lower McMurray is comprised of "water sands". These sands are barren of bitumen; having never been saturated with bitumen or, in some places, originally containing bitumen that has since been removed from the sands through the movement of basal waters over time producing "swept" zones.

The middle McMurray is comprised of thick estuarine channel successions and tidal flat deposits resulting in interbedded sands and muds. The estuarine channel sands provide good quality ore. The muddier intervals within the channels and the tidal flat deposits within the middle McMurray represent zones of interburden in the mining area.

The upper McMurray consists of shoreface/channel transition deposits and is typically thin, less than five meters. Locally, this member may be entirely eroded. Exceptional thickness of about 15 meters can be found within the upper

McMurray. In most cases, the bitumen saturation in the upper McMurray is poor and the material is included with the overburden.

FIGURE 2 - GENERAL STRATIGRAPHY OF THE HORIZON OIL SANDS PROJECT

[GRAPHIC OMITTED]

HORIZON OIL SANDS PROJECT MINING RESERVES

For the year ended December 31, 2006, the Company retained GLJ to evaluate 100 per cent of Phases 1, 2 and 3 of the Horizon Project and prepare an Evaluation Report on the Company's proved, and probable oil sands mining reserves incorporating both the mining and upgrading projects. These reserves were evaluated adhering to the requirements of SEC Industry Guide 7 using constant pricing and have been disclosed separately from the Company's conventional proved and probable crude oil, NGLs and natural gas reserves.

The pit limits and mine plans were updated in 2006 incorporating the results from the most recent and past drilling programs. Figure 3 shows the mining areas associated with the reserves and Figure 4 shows the drill hole coverage used to develop the mine plan. The oil sands mining reserves from GLJ's Evaluation Report are provided in Table 2. The 3.0 billion barrels of gross lease proved and probable synthetic crude oil reserves shown in the table are produced from 37 years of projected production from the first three phases of the project commencing in 2008.

The Reserve Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with GLJ to review the qualifications of and procedures used by the evaluator in determining the estimate of the Company's oil sands mining reserves.

FIGURE 3 - HORIZON OIL SANDS PROJECT RESOURCE AREAS AND GENERAL LAYOUT


[GRAPHIC OMITTED - PLOT MAP]

FIGURE 4 - HORIZON OIL SANDS PROJECT CORE HOLE COVERAGE



OIL SANDS MINING RESERVES

The following table sets out Canadian Natural's reserves of bitumen and synthetic crude oil from the Horizon Project as of December 31, 2006:

<TABLE>
<CAPTION>
Constant Prices

Bitumen (mmbbl)		Synthetic Crude Oil (1) (mmbbl)	
Gross Lease (2)	Net	Gross Lease (2)	Net
<S>	<C>	<C>	<C>	<C>
Total proved reserves	2,275	1,853	1,866	1,596
Total proved and probable reserves	3,530	2,872	2,962	2,542

</TABLE>

(1) Synthetic crude oil reserves are based on the upgrading of bitumen using technologies implemented at the Horizon Project. The reserves shown for bitumen and synthetic crude oil are not additive.

(2) Gross Lease reserves are the total remaining recoverable reserves on the Lease before consideration of Company interests or royalties.

E. CRUDE OIL, NGLS AND NATURAL GAS PRODUCTION

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

<TABLE>
<CAPTION>
YEAR ENDED DECEMBER 31

2006	2005	2004
<S>	<C>	<C>	<C>
Daily Production, before royalties			
Crude Oil and NGLs (bbl/d)	331,998	313,168	282,489
Natural Gas (mmcf/d)	1,492	1,439	1,388
Annual Production, before royalties			
Crude Oil and NGLs (mbbl)	121,179	114,306	103,391
Natural Gas (bcf)	545	525	508

</TABLE>

<TABLE>
<CAPTION>
NETBACKS
INFORMATION BY QUARTER

	YEAR 2006					YEAR 2005				
	1ST QUARTER	2ND QUARTER	3RD QUARTER	4TH QUARTER	YEAR ENDED	1ST QUARTER	2ND QUARTER	3RD QUARTER	4TH QUARTER	YEAR ENDED
<S>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>
Average Daily Production Volumes, before royalties										
Crude oil and NGLs (bbl/d)	323,662	338,852	321,665	343,705	331,998	287,803	289,064	334,724	340,268	313,168
Natural Gas (mcf/d)	1,436	1,475	1,437	1,620	1,492	1,455	1,454	1,423	1,423	1,439
PRODUCT NETBACKS										
Crude oil and NGLs ($/bbl)										
Sales Price (1)	43.79	60.05	62.55	47.27	53.65	$ 39.81	$ 42.51	$ 57.35	$ 46.38	$ 46.86
Royalties	3.48	5.14	5.11	4.10	4.48	$ 3.39	$ 3.33	$ 5.11	$ 3.89	$ 3.97
Production Expenses	11.33	11.92	13.47	12.32	12.29	$ 11.30	$ 11.66	$ 11.48	$ 10.33	$ 11.17
NETBACK	28.98	42.99	43.97	30.85	36.88	$ 25.12	$ 27.52	$ 40.76	$ 32.16	$ 31.72
Natural Gas ($mcf)										
Sales Price (1)	8.30	6.16	5.83	6.66	6.72	$ 6.68	$ 7.33	$ 8.61	$ 11.67	$ 8.57
Royalties	1.70	1.11	1.11	1.26	1.29	$ 1.30	$ 1.48	$ 1.93	$ 2.30	$ 1.75
Production Expenses	0.80	0.80	0.84	0.86	0.82	$ 0.69	$ 0.71	$ 0.76	$ 0.76	$ 0.73
NETBACK	5.80	4.25	3.88	4.54	4.61	$ 4.69	$ 5.14	$ 5.92	$ 8.61	$ 6.09
Light/Pelican Lake/NGLs ($/bbl)										
Sales Price (1)	58.28	69.02	71.65	57.68	64.33	$ 53.14	$ 56.85	$ 66.81	$ 58.87	$ 59.16
Royalties	4.65	5.53	5.39	4.39	5.00	$ 5.20	$ 4.55	$ 5.50	$ 4.40	$ 4.90
Production Expenses	11.15	11.18	14.12	12.99	12.42	$ 11.58	$ 12.28	$ 11.47	$ 8.90	$ 10.93
NETBACK	42.48	52.31	52.14	40.30	46.91	$ 36.36	$ 40.02	$ 49.84	$ 45.57	$ 43.33
Heavy Crude Oil ($/bbl)										
Sales Price (1)	25.22	50.08	51.38	36.11	41.20	$ 25.21	$ 27.82	$ 47.25	$ 30.27	$ 33.09
Royalties	1.98	4.71	4.76	3.78	3.88	$ 1.41	$ 2.07	$ 4.83	$ 3.08	$ 2.92
Production Expenses	11.55	12.73	12.67	11.60	12.15	$ 11.00	$ 11.03	$ 11.50	$ 12.18	$ 11.44
NETBACK	11.69	32.64	33.95	20.73	25.17	$ 12.80	$ 14.72	$ 30.92	$ 15.01	$ 18.73

</TABLE>
NOTE: Pelican Lake crude oil has an API of 12(0) to 17(0), but receives medium quality crude netbacks due to exceptionally low operating costs and low royalty rates.

(1) NET OF TRANSPORTATION AND BLENDING COSTS AND EXCLUDING RISK MANAGEMENT ACTIVITIES.

<TABLE>
<CAPTION>
NETBACKS
INFORMATION BY QUARTER

YEAR 2004	1ST QUARTER	2ND QUARTER	3RD QUARTER	4TH QUARTER	YEAR ENDED
<S>	<C>	<C>	<C>	<C>	<C>
Average Daily Production Volumes					
Crude oil and NGLs (bbl/d)	261,286	275,398	297,262	295,704	282,489
Natural Gas (mcf/d)	1,294	1,452	1,396	1,410	1,388
PRODUCT NETBACKS					
Crude oil and NGLs ($/bbl)					
Sales Price (1)	$ 34.21	$ 36.72	$ 43.50	$ 36.92	$ 37.99
Royalties	$ 2.91	$ 3.15	$ 3.59	$ 2.95	$ 3.16
Production Expenses	$ 9.58	$ 9.92	$ 10.21	$ 10.41	$ 10.05
NETBACK	$ 21.72	$ 23.65	$ 29.70	$ 23.56	$ 24.78
Natural Gas ($/mcf)					
Sales Price (1)	$ 6.31	$ 6.64	$ 6.24	$ 6.77	$ 6.50
Royalties	$ 1.27	$ 1.38	$ 1.39	$ 1.34	$ 1.35
Production Expenses	$ 0.65	$ 0.66	$ 0.71	$ 0.68	$ 0.67
NETBACK	$ 4.39	$ 4.60	$ 4.14	$ 4.75	$ 4.48
CRUDE OIL AND NGLS NETBACKS BY TYPE					
Light/Pelican Lake/NGLs ($/bbl)					
Sales Price (1)	$ 40.75	$ 45.28	$ 51.54	$ 48.60	$ 46.71
Royalties	$ 3.71	$ 3.98	$ 3.99	$ 4.12	$ 3.95
Production Expenses	$ 9.77	$ 10.36	$ 10.70	$ 11.20	$ 10.53
NETBACK	$ 27.27	$ 30.94	$ 36.85	$ 33.28	$ 32.23
Heavy Crude Oil ($/bbl)					
Sales Price (1)	$ 27.00	$ 28.08	$ 35.33	$ 25.16	$ 28.99
Royalties	$ 2.02	$ 2.31	$ 3.18	$ 1.77	$ 2.34
Production Expenses	$ 9.38	$ 9.47	$ 9.72	$ 9.62	$ 9.56
NETBACK	$ 15.60	$ 16.30	$ 22.43	$ 13.77	$ 17.09

</TABLE>
NOTE: Pelican Lake crude oil has an API of 12(0) to 17(0), but receives medium quality crude netbacks due to exceptionally low operating costs and low royalty rates.

(1) NET OF TRANSPORTATION AND BLENDING COSTS AND EXCLUDING RISK MANAGEMENT ACTIVITIES.

<TABLE>
<CAPTION>
NETBACKS
INFORMATION BY QUARTER

	YEAR 2006					YEAR 2005				
	1ST QUARTER	2ND QUARTER	3RD QUARTER	4TH QUARTER	YEAR ENDED	1ST QUARTER	2ND QUARTER	3RD QUARTER	4TH QUARTER	YEAR ENDED
<S>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>
SEGMENTED										
NORTH AMERICA PRODUCT NETBACKS										
Light/Pelican Lake/NGLs ($/bbl)										
Sales Price (1)	$48.83	$64.35	$65.15	$48.47	$56.52	$45.80	$49.78	$61.21	$52.10	$52.35
Royalties	$ 8.98	$10.87	$10.86	$ 7.80	$ 9.59	$10.64	$ 8.77	$11.49	$ 9.62	$10.13
Production Expenses	$ 9.86	$ 9.75	$10.81	$13.18	$10.93	$ 8.30	$ 8.40	$ 9.27	$ 8.60	$ 8.65
NETBACK	$29.99	$43.73	$43.48	$27.49	$36.00	$26.86	$32.61	$40.45	$33.88	$33.57
Heavy Crude Oil ($/bbl)										
Sales Price (1)	$25.22	$50.08	$51.38	$36.11	$41.20	$25.21	$27.82	$47.25	$30.27	$33.09
Royalties	$ 1.98	$ 4.71	$ 4.76	$ 3.78	$ 3.88	$ 1.41	$ 2.07	$ 4.83	$ 3.08	$ 2.92
Production Expenses	$11.55	$12.73	$12.67	$11.60	$12.15	$11.00	$11.03	$11.50	$12.18	$11.44
NETBACK	$11.69	$32.64	$33.95	$20.73	$25.17	$12.80	$14.72	$30.92	$15.01	$18.73
Natural Gas ($/mcf)										
Sales Price (1)	$ 8.39	$ 6.21	$ 5.86	$ 6.70	$ 6.77	$ 6.73	$ 7.38	$ 8.69	$11.79	$ 8.65
Royalties	$ 1.73	$ 1.13	$ 1.12	$ 1.29	$ 1.31	$ 1.33	$ 1.50	$ 1.96	$ 2.34	$ 1.78
Production Expenses	$ 0.79	$ 0.79	$ 0.83	$ 0.84	$ 0.81	$ 0.66	$ 0.68	$ 0.74	$ 0.74	$ 0.71
NETBACK	$ 5.87	$ 4.29	$ 3.91	$ 4.57	$ 4.65	$ 4.74	$ 5.20	$ 5.99	$ 8.71	$ 6.16
NORTH SEA PRODUCT NETBACKS										
Light Crude Oil ($/bbl)										
Sales Price (1)	$68.05	$73.19	$78.68	$67.72	$72.62	$59.56	$64.81	$74.46	$66.88	$66.57
Royalties	$ 0.12	$ 0.17	$ 0.11	$ 0.14	$ 0.13	$ 0.05	$ 0.11	$ 0.12	$ 0.14	$ 0.10
Production Expenses	$16.85	$17.18	$20.28	$14.76	$17.57	$14.91	$17.41	$15.15	$12.11	$14.94
NETBACK	$51.08	$55.84	$58.29	$52.82	$54.92	$44.60	$47.29	$59.19	$54.63	$51.53
Natural Gas ($/mcf)										
Sales Price (1)	$ 2.38	$ 2.33	$ 2.38	$ 3.48	$ 2.66	$ 3.52	$ 3.07	$ 2.64	$ 3.40	$ 3.17
Royalties	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Expenses	$ 1.26	$ 1.47	$ 1.30	$ 1.54	$ 1.40	$ 2.52	$ 2.92	$ 2.30	$ 1.96	$ 2.44
NETBACK	$ 1.12	$ 0.86	$ 1.08	$ 1.94	$ 1.26	$ 1.00	$ 0.15	$ 0.34	$ 1.44	$ 0.73
OFFSHORE WEST AFRICA PRODUCT NETBACKS										
Light Crude Oil ($/bbl)										
Sales Price (1)	$65.23	$72.97	$70.59	$63.50	$67.99	$62.34	$58.24	$59.09	$60.19	$59.91
Royalties	$ 1.55	$ 1.87	$ 4.89	$ 3.02	$ 2.81	$ 1.90	$ 1.81	$ 1.54	$ 1.57	$ 1.62
Production Expenses	$ 6.08	$ 5.61	$ 7.97	$10.05	$ 7.45	$11.43	$ 8.47	$ 5.81	$ 5.62	$ 6.50
NETBACK	$57.60	$65.49	$57.73	$50.43	$57.73	$49.01	$47.96	$51.74	$53.00	$51.79
Natural Gas ($/mcf)										
Sales Price (1)	$ 5.59	$ 5.30	$ 4.97	$ 5.72	$ 5.37	$ 7.67	$ 6.88	$ 5.52	$ 5.13	$ 5.91
Royalties	$ 0.13	$ 0.14	$ 0.34	$ 0.27	$ 0.22	$ 0.23	$ 0.21	$ 0.13	$ 0.14	$ 0.16
Production Expenses	$ 1.00	$ 0.36	$ 1.39	$ 2.01	$ 1.19	$ 1.25	$ 1.37	$ 1.09	$ 0.80	$ 1.05
NETBACK	$ 4.46	$ 4.80	$ 3.24	$ 3.44	$ 3.96	$ 6.19	$ 5.30	$ 4.30	$ 4.19	$ 4.70

</TABLE>

NOTE: Pelican Lake crude oil has an API of 12(0) to 17(0), but receives medium quality crude netbacks due to exceptionally low operating costs and low royalty rates.

(1) NET OF TRANSPORTATION AND BLENDING COSTS AND EXCLUDING RISK MANAGEMENT ACTIVITIES.

<TABLE>
<CAPTION>
NETBACKS
INFORMATION BY QUARTER

YEAR 2004				
1ST QUARTER	2ND QUARTER	3RD QUARTER	4TH QUARTER	YEAR ENDED
<S>	<C>	<C>	<C>	<C>
SEGMENTED				
NORTH AMERICA PRODUCT NETBACKS				
Light/Pelican Lake/NGLs ($/bbl)				
Sales Price (1)	$37.54	$ 41.03	$ 44.89	$ 43.80	$ 41.81
Royalties	$ 7.20	$ 7.91	$ 8.59	$ 8.76	$ 8.12
Production Expenses	$ 7.30	$ 7.74	$ 7.75	$ 7.85	$ 7.66
NETBACK	$23.04	$ 25.38	$ 28.55	$ 27.19	$ 26.03
Heavy Crude Oil ($/bbl)					
Sales Price (1)	$27.00	$ 28.08	$ 35.33	$ 25.16	$ 28.99
Royalties	$ 2.02	$ 2.31	$ 3.18	$ 1.77	$ 2.34
Production Expenses	$ 9.38	$ 9.47	$ 9.72	$ 9.62	$ 9.56
NETBACK	$15.60	$ 16.30	$ 22.43	$ 13.77	$ 17.09
Natural Gas ($/mcf)					
Sales Price (1)	$ 6.37	$ 6.78	$ 6.36	$ 6.88	$ 6.61
Royalties	$ 1.33	$ 1.44	$ 1.45	$ 1.39	$ 1.40
Production Expenses	$ 0.60	$ 0.60	$ 0.63	$ 0.63	$ 0.62
NETBACK	$ 4.44	$ 4.74	$ 4.28	$ 4.86	$ 4.59
NORTH SEA PRODUCT NETBACKS					
Light Crude oil ($/bbl)					
Sales Price (1)	$44.27	$ 49.22	$ 57.39	$ 52.77	$ 51.37
Royalties	$ 0.06	$ 0.10	$ 0.09	$ 0.08	$ 0.08
Production Expenses	$13.26	$ 13.84	$ 13.88	$ 14.96	$ 14.03
NETBACK	$30.95	$ 35.28	$ 43.42	$ 37.73	$ 37.26
Natural Gas ($/mcf)					
Sales Price (1)	$ 5.08	$ 3.28	$ 3.17	$ 3.26	$ 3.73
Royalties	$ -	$ -	$ -	$ -	$ -
Production Expenses	$ 1.65	$ 1.92	$ 2.48	$ 2.29	$ 2.07
NETBACK	$ 3.43	$ 1.36	$ 0.69	$ 0.97	$ 1.66
OFFSHORE WEST AFRICA PRODUCT NETBACKS					
Light Crude oil ($/bbl)					
Sales Price (1)	$42.08	$ 49.34	$ 53.86	$ 51.28	$ 49.05
Royalties	$ 1.28	$ 1.52	$ 1.42	$ 1.52	$ 1.43
Production Expenses	$ 7.09	$ 7.43	$ 8.05	$ 7.82	$ 7.59
NETBACK	$33.71	$ 40.39	$ 44.39	$ 41.94	$ 40.03
Natural Gas ($/mcf)					
Sales Price (1)	$ 4.80	$ 5.18	$ 6.31	$ 4.73	$ 5.25
Royalties	$ 0.15	$ 0.16	$ 0.17	$ 0.14	$ 0.15
Production Expenses	$ 1.23	$ 1.38	$ 1.39	$ 1.31	$ 1.33
NETBACK	$ 3.42	$ 3.64	$ 4.75	$ 3.28	$ 3.77

</TABLE>

NOTE: Pelican Lake crude oil has an API of 12(0) to 17(0), but receives medium quality crude netbacks due to exceptionally low operating costs and low royalty rates.

(1) NET OF TRANSPORTATION AND BLENDING COSTS AND EXCLUDING RISK MANAGEMENT ACTIVITIES..

F. HISTORICAL DRILLING ACTIVITY BY PRODUCT

The following table sets forth the gross and net wells (excluding service and stratigraphic test wells) in which the Company has participated for the period indicated:

<TABLE>
<CAPTION>
YEAR ENDED DECEMBER 31

2006		2005	
Gross	Net	Gross	Net
<S>	<C>	<C>	<C>	<C>	<C>
Natural Gas	855	641	1,071	890
Crude Oil	666	603	685	627
Service/Stratigraphic	376	375	251	248
Dry Holes	133	119	136	117
Total	2,030	1,738	2,143	1,882
Total Success Rate	91%		93%	

</TABLE>

G. NET 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. Net capital expenditures do not include non-cash property, plant and equipment additions and disposals.

<TABLE>
<CAPTION>

YEAR ENDED DECEMBER 31		
	2006	2005
$millions		
<S>	<C>	<C>
Net property acquisitions (dispositions)	(1) 4,733	(320)
Land acquisition and retention	210	254
Seismic evaluations	130	132
Well drilling, completion and equipping	2,340	2,000
Pipeline and production facilities	1,314	1,295
Reserve replacement expenditures	8,727	3,361
Horizon Project:		
Phase 1 construction costs (2)	2,768	1,249
Phase 2 and 3 costs	79	-
Capitalized interest, stock based compensation and other (2)	338	250
Total Horizon Project	3,185	1,499
Midstream	12	4
Abandonments (3)	75	46
Head office	26	22
Total Net Capital Expenditures	12,025	4,932

</TABLE>

<TABLE>
<CAPTION>
2006 THREE MONTHS ENDED

($ millions)

CAPITAL EXPENDITURES BY QUARTER	MAR. 31	JUNE 30	SEPT. 30	DEC. 31
<S>	<C>	<C>	<C>	<C>
Net property acquisitions (dispositions) (1)	12	7	(6)	4,720
Land acquisition and retention	99	54	29	28
Seismic evaluation	52	35	26	17
Well drilling, completion and equipping	936	418	524	462
Pipeline and production facilities	500	233	270	311
Reserve replacement expenditures	1,599	747	843	5,538
Horizon Project:				
Phase 1 construction costs (2)	616	680	727	745
Phase 2 and 3 costs	1	6	18	54
Capitalized interest, stock based compensation and other (2)	69	96	39	134
Total Horizon Project	686	782	784	933
Midstream	3	6	2	1
Abandonments (3)	15	17	24	19
Head office	6	6	8	6
Total Net Capital Expenditures	2,309	1,558	1,661	6,497

</TABLE>

<TABLE>
<CAPTION>
2005 THREE MONTHS ENDED

($ millions)

CAPITAL EXPENDITURES BY QUARTER	MAR. 31	JUNE 30	SEPT. 30	DEC. 31
<S>	<C>	<C>	<C>	<C>
Net property acquisitions (dispositions)(1)	2	(341)	-	19
Land acquisition and retention	36	52	69	97
Seismic evaluation	41	20	31	40
Well drilling, completion and equipping	634	306	431	629
Pipeline and production facilities	432	283	266	314
Reserve replacement expenditures	1,145	320	797	1,099
Horizon Project				
Phase 1 construction costs (2)	131	236	413	469
Phase 2 and 3 costs	-	-	-	-
Capitalized interest, stock based compensation and other (2)	84	39	39	88
Total Horizon Project	215	275	452	557
Midstream	4	-	(1)	1
Abandonments (3)	4	7	19	16
Head office	4	7	5	6
Total Net Capital Expenditures	1,372	609	1,272	1,679

</TABLE>

(1) Includes Business Combinations

(2) Certain prior period amounts have been reclassified with respect to stock-based compensation costs.

(3) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

H. UNDEVELOPED ACREAGE

The following table summarizes the Company's working interest holdings in core region undeveloped acreage as at December 31, 2006:

	GROSS ACRES	NET ACRES
	(thousands)	(thousands)
NORTH AMERICA		
Alberta	11,298	9,363
British Columbia	3,752	2,692
Saskatchewan	787	719
Manitoba	11	11
NORTH SEA		
United Kingdom	367	299
OFFSHORE WEST AFRICA		
Cote d'Ivoire	95	55
Gabon	152	152
Total	16,462	13,291

I. DEVELOPED ACREAGE

The following table summarizes the Company's working interest holdings in core region developed acreage as at December 31, 2006:

	GROSS ACRES	NET ACRES
	(thousands)	(thousands)
NORTH AMERICA		
Alberta	6,398	5,078
British Columbia	1,319	996
Saskatchewan	340	287
Manitoba	5	5
NORTH SEA		
United Kingdom	138	93
OFFSHORE WEST AFRICA		
Cote d'Ivoire	7	4
Total	8,207	6,463

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:

<TABLE>
<CAPTION>

YEAR ENDED DECEMBER 31		
	2006	2005
($ millions, except per share information)		
<S>	<C>	<C>
Revenues (1) (net of royalties)	10,398	9,764
Cash flow from operations	4,932	5,021
Per common share - basic	9.18	9.36
- diluted	9.18	9.33
Net earnings	2,524	1,050
Per common share - basic	4.70	1.96
- diluted	4.70	1.95
Total assets	33,160	21,852
Total long-term debt	11,043	3,321

</TABLE>

<TABLE>
<CAPTION>

2006 THREE MONTHS ENDED				
	MARCH 31	JUNE 30	SEPT. 30	DEC. 31
($ millions, except per share information)				
<S>	<C>	<C>	<C>	<C>
Revenues (1) (net of royalties)	2,352	2,739	2,798	2,509
Net earnings	57	1,038	1,116	313
Per common share - basic	0.11	1.93	2.08	0.58
- diluted	0.11	1.93	2.08	0.58

2005 THREE MONTHS ENDED				
	MARCH 31	JUNE 30	SEPT. 30	DEC. 31
($ millions, except per share information)				
Revenues (1) (net of royalties)	1,969	2,137	2,760	2,898
Net (loss) earnings	(424)	219	151	1,104
Per common share - basic	(0.79)	0.41	0.28	2.06
- diluted	(0.79)	0.41	0.28	2.06

</TABLE>

(1) Blending costs previously netted against gross revenues in prior years have been reclassified to transportation and blending expense to conform to the presentation adopted in 2006..

CAPITAL STRUCTURE

COMMON SHARES

The Company is authorized to issue an unlimited number of common shares, without nominal or par value. Holders of common shares are entitled to one vote per share at a meeting of shareholders of Canadian Natural, to receive such dividends as declared by the Board of Directors on the common shares and to receive pro-rata the remaining property and assets of the Company upon its dissolution or winding-up, subject to any rights having priority over the common shares.

PREFERRED SHARES

The Company has no preferred shares outstanding; however, the Company is authorized to issue two hundred thousand (200,000) preferred shares designated as Class 1 Preferred Shares. Holders of preferred shares shall not be entitled as such to receive notice of or to attend any meeting of the shareholders of the Company and shall not be entitled to vote at any such meeting except under certain circumstances as described in the Articles of Amalgamation. Holders of preferred shares are entitled to receive such dividends as and when declared by the Board of Directors in priority to common shares and shall be entitled to receive pro-rata in priority to holders of commons shares the remaining property and assets of Canadian Natural upon its dissolution or winding-up. The Company may redeem or purchase for cancellation at any time all or any part of the then outstanding preferred shares and the holders of the preferred shares shall have the right at any time and from time to time to convert such preferred shares into the common shares of the Company.

CREDIT RATINGS

Credit ratings accorded to the Company's debt securities are not recommendations to purchase, hold or sell the debt securities inasmuch as such ratings do not comment as to market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant, and if any such rating is so revised or withdrawn, we are under no obligation to update this Annual Information Form.

The Company is rated "Baa2" with a stable outlook by Moody's Investors Service, Inc. ("Moody's"), "BBB" by Standard & Poor's Corporation ("S&P") with a stable outlook and "BBB high" with a negative trend by DBRS.

Moody's credit ratings are on a long-term debt rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. According to the Moody's rating system, debt securities rated Baa are considered as medium-grade obligations, i.e., they are neither highly protected nor poorly secured. Interest payments and principal security appear adequate for the present, but certain protective elements may be lacking or may be characteristically unreliable over any great length of time. Such securities lack outstanding investment characteristics and in fact have speculative characteristics as well. Moody's applies numerical modifiers 1, 2 and 3 in each generic rating classification from Aa through Caa in its corporate bond rating system. The modifier 1 indicates that the issue ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates that the issue ranks in the lower end of its generic rating category. A Moody's rating outlook is an opinion regarding the likely direction of a rating over the medium term.

S&P's credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. According to the S&P rating system, debt securities rated BBB exhibit adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments on the debt securities. The ratings from AA to B may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. An S&P rating outlook assesses the potential direction of a long term credit rating over the intermediate to longer term. In determining a rating outlook, consideration is given to any changes in the economic and/or fundamental business conditions.

DBRS' credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. According to the DBRS rating system, debt securities rated BBB are of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions. The assignment of a "(high)" or "(low)" modifier within each rating category indicates relative standing within such category. The rating trend is DBRS' opinion regarding the outlook for the rating.

MARKET FOR CANADIAN NATURAL RESOURCES LIMITED SECURITIES

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

2006 Monthly Historical Trading on Toronto Stock Exchange

Month	High	Low	Close	Volume Traded
January	$71.65	$57.75	$70.60	40,613,480
February	73.91	58.96	62.09	50,126,147
March	68.93	61.75	64.90	43,747,239
April	72.70	65.58	67.20	28,568,500
May	69.37	54.39	58.00	52,879,861
June	62.75	50.78	61.72	47,587,703
July	62.60	54.59	60.10	31,911,426
August	63.30	56.89	58.03	38,653,456
September	58.59	47.28	50.94	56,457,171
October	60.73	45.49	58.45	50,270,814
November	62.50	54.21	61.90	42,470,275
December	63.50	58.64	62.15	25,649,324

On January 22, 2004, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of TSX and the NYSE, commencing January 24, 2004 and ending January 23, 2005, to purchase for cancellation up to 6,690,385 (13,380,770 post May 21, 2004 two-for-one stock split) common shares of the Company, being 5 per cent of the 133,807,695 (267,615,390 post May 21, 2004 two-for-one stock split) common shares of the Company outstanding on January 13, 2004. Under this program, the Company purchased a total of 873,400 common shares for cancellation at an average purchase price of $37.98 for each common share purchased, $38.01 after costs.

At the Annual and Special Meeting of Shareholders held May 6, 2004, the shareholders passed a special resolution amending the Articles of the Company

to divide the issued and outstanding Common Shares on a two-for-one basis. The subdivision of the Common Shares occurred on May 21, 2004.

On January 20, 2005, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of Toronto Stock Exchange and the New York Stock Exchange, commencing January 24, 2005 and ending January 23, 2006, to purchase for cancellation up to 13,409,006 (26,818,012 post May 20, 2005 two-for-one stock split) common shares of the Company, being 5 per cent of the 268,180,123 (536,360,246 post May 20, 2005 two-for-one stock split) common shares of the Company outstanding on January 12, 2005. Under this program, the Company purchased a total of 850,000 common shares for cancellation at a weighted average purchase price of $53.26 for each common share purchased, $53.29 after costs.

At the Annual and Special Meeting of Shareholders held May 5, 2005, the shareholders passed a special resolution amending the Articles of the Company to divide the issued and outstanding Common Shares on a two-for-one basis. The subdivision of the Common Shares occurred on May 20, 2005.

On January 20, 2006, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of TSE and the NYSE, commencing January 24, 2006 and ending January 23, 2007, to purchase for cancellation up to 26,852,545 common shares of the Company, being 5 per cent of the 537,050,902 common shares of the Company outstanding on January 17, 2006. Under this program, the Company purchased a total of 485,000 common shares for cancellation at a weighted average purchase price of $57.29 for each common share purchased, $57.33 after costs.

On January 22, 2007, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of TSE and the NYSE, commencing January 24, 2007 and ending January 23, 2008, to purchase for cancellation up to 26,941,730 common shares of the Company, being 5 per cent of the 538,834,606 common shares of the Company outstanding on January 15, 2007. As of the date of this Annual Information Form, no shares have been purchased under the program.

DIVIDEND HISTORY

The dividend policy of the Company undergoes a 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. 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 regular quarterly dividends. Dividends have been paid on the first day of January, April, July and October of each year since 2001.

The following table, restated for the two-for-one subdivision of the common shares which occurred in May 2004 and May 2005, shows the aggregate amount of the cash dividends declared per common share of the Company and accrued in each of its last three years ended December 31.

	2006	2005	2004
Cash dividends declared per common share	$0.30	$0.24	$0.20

TRANSFER AGENTS AND REGISTRAR

The Company's transfer agent and registrar for its common shares is Computershare Trust Company of Canada in the cities of Calgary and Toronto and Computershare Shareholder Services, Inc. in the city of New York. The registers for transfers of the Company's common shares are maintained by Computershare Trust Company of Canada.

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:

<TABLE>
<CAPTION>

NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
<S>	<C>	<C>
Catherine M. Best Calgary, Alberta Canada	Director(2) (4) (age 53)	Executive Vice-President, Risk Management and Chief Financial Officer of the Calgary Health Region from 2002 to present; Vice-President, Corporate Services and Chief Financial Officer of the Calgary Health Region from February 2000 to 2002; prior thereto with Ernst & Young since 1980, most recently as a Corporate Audit Partner from 1991 to 2000. Has served continuously as a director of the Company since November 2003. Currently serving on the board of directors of Enbridge Income Fund.
N. Murray Edwards Calgary/Banff, Alberta Canada	Vice-Chairman and Director(3) (age 47)	President, Edco Financial Holdings Ltd. (a private management and consulting company). Has served continuously as a director of the Company since September 1988. Currently serving on the board of directors of Ensign Energy Services Inc. and Magellan Aerospace Corporation.
Honourable Gary A. Filmon Winnipeg, Manitoba Canada	Director (1)(2) (age 64)	Consultant, Exchange Group (business consulting firm based in Winnipeg, Manitoba). Prior thereto, served as Premier of Manitoba from 1988 to 1999. Has served continuously as a director of the Company since February 2006. Currently serving on the board of directors of MTS Allstream Inc., Pollard Banknote Income Fund, Arctic Glacier Income Trust, Exchange Industrial Income Fund, Wellington West Capital Inc. and FWS Construction Inc.
Ambassador Gordon D. Giffin Atlanta, Georgia USA	Director(1)(2) (age 57)	Senior Partner, McKenna Long & Aldridge LLP (law firm) since May 2001; prior thereto United States Ambassador to Canada. Has served continuously as a director of the Company since May 2002. Currently serving on the board of directors of Bowater, Inc.; Canadian National Railway; Canadian Imperial Bank of Commerce, Ontario Energy Savings Corp. and, Transalta Corporation.
John G. Langille Calgary, Alberta Canada	Vice-Chairman and Director (age 61)	Officer of the Company. Has served continuously as a director of the Company since June 1982.
Steve W. Laut Calgary, Alberta Canada	President and Chief Operating Officer and Director (age 49)	President and Chief Operating Officer of the Company since April 2005. Prior thereto Executive Vice-President, Operations 2001 to 2003 and most recently Chief Operating Officer 2003 to 2005. Has served continuously as a director of the Company since August 2006.

</TABLE>

NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
Keith A.J. MacPhail Calgary, Alberta Canada	Director(3)(5) (age 50)	Chairman, President and Chief Executive Officer, Bonavista Petroleum Ltd. since November 1997 and Chairman, President and Chief Executive Officer of Bonavista Energy Trust and Chairman, NuVista Energy Ltd since July 2003. Has served continuously as a director of the Company since October 1993. Currently serving on the board of directors of Bonavista Energy Trust and NuVista Energy Ltd.
Allan P. Markin Calgary, Alberta Canada	Chairman and Director(5) (age 61)	Chairman of the Company. Has served continuously as a director of the Company since January 1989.
Norman F. McIntyre Calgary, Alberta Canada	Director(3)(4)(5) (age 61)	An independent businessman. Prior thereto Executive Vice-President, Petro-Canada from 1995 to 2002 and most recently President, Petro-Canada 2002 to 2004. Has served continuously as a director of the Company since July 2005. Currently serving on the board of directors of Signal Energy Inc. and Petro Andina Resources, a private company.
Frank J. McKenna Cap Pele, New Brunswick Canada	Director(1)(4) (age 59)	Deputy Chair, TD Bank Financial Group. Prior thereto Premier of New Brunswick from 1987 to 1997; Counsel to Atlantic Canada law firm McInnes Cooper from 1998 to 2005, and most recently Canadian Ambassador to the United States from 2005 to 2006. He has served continuously as a director of the Company since August 2006. Currently serving on the board of directors of Brookfield Asset Management Inc.; and, Perseus Private Equity a private equity fund management company.
James S. Palmer, C.M., A. O. E., Q.C. Calgary, Alberta Canada	Director(3)(4)(5) (age 78)	Chairman and a Partner of Burnet, Duckworth & Palmer LLP (law firm). Has served continuously as a director of the Company since May 1997. Currently serving on the board of directors of Magellan Aerospace Corporation; Rally Energy Corp.; and, Energy Resources Alberta.
Dr. Eldon R. Smith, OC, M.D. Calgary, Alberta Canada	Director(4)(5) (age 67)	Emeritus Professor and Former Dean, Faculty of Medicine, University of Calgary. Has served continuously as a director of the Company since May 1997. Currently serving on the board of directors of Vasogen Inc., Sernova Corp.; and, Overlord Financial Inc.
David A. Tuer Calgary, Alberta Canada	Director(1)(2)(3) (age 57)	Chairman, Calgary Health Region since October 2001 and Executive Vice-Chairman BA Energy Inc. since April 2005. Prior thereto President and Chief Executive Officer, PanCanadian Energy Corporation from December 1994 to October 2001, President and CEO of Hawker Resources Inc. (independent oil and natural gas company) from January 2003 to March 2005 and most recently President, Value Creation Inc. from April 2005 to February 2006. Has served continuously as a director of the Company since May 2002. Currently serving on the board of directors of BA Energy Inc; Rockwater Capital Corporation; Daylight Resources Trust; Xtreme Coil Drilling Corp. and, Altalink Management Ltd. a private company.
Real M. Cusson Calgary, Alberta Canada	Senior Vice-President, Marketing (age 56)	Officer of the Company.
Real J. H. Doucet Calgary, Alberta Canada	Senior Vice-President, Oil Sands (age 54)	Officer of the Company.

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NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
<S>	<C>	<C>
Allen M. Knight Calgary, Alberta Canada (age 57)	Senior Vice-President, International & Corporate Development	Officer of the Company.
Tim S. McKay Calgary, Alberta Canada	Senior Vice-President, Operations (age 45)	Officer of the Company.
Douglas A. Proll Calgary, Alberta Canada (age 56)	Chief Financial Officer and Senior Vice-President, Finance	Officer of the Company.
Lyle G. Stevens Calgary, Alberta Canada	Senior Vice-President, Exploitation (age 52)	Officer of the Company.
Jeffrey W. Wilson Calgary, Alberta Canada	Senior Vice-President, Exploration (age 54)	Officer of the Company since September 2003; prior thereto Exploration Manager of the Company.
Corey B. Bieber Calgary, Alberta Canada	Vice-President, Finance and Investor Relations (age 43)	Officer of the Company since April 2005; prior thereto Treasurer of the Company March 2001 to July 2002; Director, Investor Relations of the Company from July 2002 to April 2005 and most recently Vice-President, Investor Relations April 2005 to February 2007.
Mary-Jo Case Calgary, Alberta Canada	Vice-President, Land (age 48)	Officer of the Company since May 2002; prior thereto Co-ordinator Land at PanCanadian Petroleum Limited to 1999 and most recently Manager Commercial Ventures and Land at PanCanadian Petroleum Limited 1999 to 2002.
William R. Clapperton Calgary, Alberta Canada (age 44)	Vice-President, Regulatory, Stakeholder and Environmental Affairs	Officer of the Company since January 2002.
James F. Corson Calgary, Alberta Canada	Vice-President, Human Resources, Horizon (age 56)	Officer of the Company since January 2007; prior thereto Vice-President, Human Resources of Qatar Petroleum Corp. from March 1997 to July 2005 and most recently Director Human Resources and Stakeholder Relations of the Company from July 2005 to 2007.
Gordon M. Coveney Calgary, Alberta Canada	Vice-President, Exploration, East (age 53)	Officer of the Company since September 2003; prior thereto Exploration Manager for the Company.
Randall S. Davis Calgary, Alberta Canada	Vice-President, Finance and Accounting (age 40)	Officer of the Company since July 2004; prior thereto Manager, Financial Reporting of the Company to July 2002; Financial Controller of the Company from July 2002 to July 2004 and most recently Vice-President Financial Accouting and Controls July 2004 to February 2007.
Allan Frankiw Calgary, Alberta Canada	Vice-President, Production, Central (age 50)	Officer of the Company since March 2007; prior thereto Manager Midstream for Anadarko Canada Corporation from November 1998 to March 2005, Manager Facilities & Construction for Anadarko Canada Corporation from April 2005 to November 2006, and most recently Manager Production of the Company from November 2006 to March 2007.

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NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
<S>	<C>	<C>
Larry C. Galea Calgary, Alberta Canada	Vice-President, Exploitation, Central (age 41)	Officer of the Company since April 2005; prior thereto Exploitation Manager of the Company to January 2002, Manager, Operations Planning of the Company January 2002 to April 2004, and most recently Exploitation Manager of the Company from April 2004 to April 2005.
Jerome W. Harvey Calgary, Alberta Canada	Vice-President, Commercial Operations (age 53)	Officer of the Company since April 2004; prior thereto Manager, Commercial Operations.
Peter Janson Calgary, Alberta Canada	Vice-President, Engineering Integration (age 49)	Officer of the Company since December 2004; prior thereto Director, Production Planning and Control at Suncor Oil Sands to June 2000 and Director, Health and Safety and Environment from June 2000 to November 2002 at Suncor Oil Sands and most recently Director, Engineering Integration of the Company from November 2002 to December 2004.
Terry J. Jocksch Calgary, Alberta Canada	Vice-President, Exploitation West (age 39)	Officer of the Company since April 2004; prior thereto Exploitation Manager of the Company to April 2004.
Christopher M. Kean Calgary, Alberta Canada (age 43)	Vice-President, Utilities and Offsite, Horizon Oil Sands Project	Officer of the Company since December 2004; prior thereto Manager Facilities Engineering of the Company to January 2002 , Utilities and Offsites Project Manager of the Company January 2002 to July 2002, Director, Utilities and Offsites of the Company July 2002 to July 2003 and most recently General Manager, Utilities and Offsites of the Company July 2003 to December 2004.
Philip A. Keele Calgary, Alberta Canada	Vice-President, Mining, Horizon Oil Sands Project (age 47)	Officer of the Company since December 2004; prior thereto Mine Manager at Fording Coal Limited to February 2001, Chief Mine Engineer of the Company February 2001 to September 2002 and most recently Director, Mine Engineering of the Company from September 2002 to December 2004.
Cameron S. Kramer Calgary, Alberta Canada	Vice-President, Development Operations (age 39)	Officer of the Company since September 2002; prior thereto Production Engineer of the Company to March 2000, Manager, Field Operations of the Company from April 2000 to September 2002, Vice-President, Field Operations of the Company September 2002 until November 2006 and most recently Vice-President Production Central of the Company November 2006 to March 2007.
Richard P. Lock Calgary, Alberta Canada	Vice-President, Bitumen Production (age 41)	Officer of the Company since July 2006; prior thereto Senior Manager Production of Diavik Diamond Mines Inc. June 2002 to October 2003 and Vice-President Development October 2003 to June 2004 of Diavik Diamond Mines Inc., Project Manager Extraction of the Company June 2004 to July 2005 and most recently General Manager, Bitumen Production of the Company July 2005 to July 2006.
Leon Miura Calgary, Alberta	Vice-President, Upgrading (age 52)	Officer of the Company since August 2003; prior thereto held progressively senior positions at Petroleos de Canada Venezuela including Cerro Negro Execution Manager, Heavy Oil Upgrading from 1997 to 2001 and most recently Nitrogen Injection Project Director, Secondary Recovery at Petroleos de Venezuela 2002 to 2003.
John S. J. Parr Calgary, Alberta Canada	Vice-President, Production, East (age 45)	Officer of the Company since April 2004; prior thereto Production Engineer, NE Gas of the Company to July 2001, Manager, Production Engineering of the Company from July 2001 to June 2002 and most recently Production Manager, Heavy Oil of the Company from July 2002 to April 2004.

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NAME	POSITION HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
<S>	<C>	<C>
David A. Payne Calgary, Alberta Canada	Vice-President, Exploitation, East (age 45)	Officer of the Company since October 2004; prior thereto Exploitation Manager, Thermal Heavy of the Company to July 2000, Director, Exploitation of CNR International (U.K.) Limited a wholly-owned subsidiary of the Company from July 2000 to August 2003 and most recently Exploitation Manager, Technical Projects of the Company from August 2003 to October 2004.
William R. Peterson Calgary, Alberta Canada	Vice-President, Production, West (age 40)	Officer of the Company since April 2004; prior thereto Production Manager, West of the Company.
John C. Puckering Calgary, Alberta Canada	Vice President, Site Development (age 60)	Officer of the Company since April 2004; prior thereto General Manager DCL Construction Inc. to November 2001, President of 960925 Alberta Ltd. from November 2001 to April 2002, Manager, Site Development of the Company from May 2002 to December 2002 and most recently General Manager Site Development of the Company from January 2003 to April 2004.
Timothy G. Reed Calgary, Alberta Canada	Vice-President, Human Resources (age 50)	Officer of the Company since January 2007; prior thereto Manager, Human Resources of the Company 2000 to 2005 and most recently Director, Human Resources 2005 to January 2007.
Sheldon L. Schroeder Calgary, Alberta Canada	Vice-President, Project Control (age 39)	Officer of the Company since April 2004; prior thereto engineer with 729248 Alberta Ltd. to June 2001, Project Control Manager of the Company from June 2001 to September 2002 and most recently Director, Project Control of the Company from September 2002 to April 2004.
Kendall W. Stagg Calgary, Alberta Canada	Vice-President, Exploration, West (age 45)	Officer of the Company since October 2004; prior thereto Cardium Geophysicist of the Company to April 2001, Chief Geophysicist of the Company from April 2001 to June 2002 and most recently Manager Exploration, B. C. of the Company from June 2002 to September 2004.
Scott G. Stauth Calgary, Alberta Canada	Vice-President, Field Operations (age 49)	Officer of the Company since November 2006; prior thereto Operations Superintendent of the Company April 1997 to April 2003 and most recently Manager, Eastern Field Operations of the Company April 2003 to November 2006.
Stephen C. Suche Calgary, Alberta Canada (age 47)	Vice-President, Information and Corporate Services	Officer of the Company since July 2006; prior thereto Manager Information and Corporate Services of the Company January 2000 to July 2006.
Domenic Torriero Calgary, Alberta Canada	Vice-President, Exploration (age 42)	Officer of the Company since November 2006; prior thereto Vice-President Geology and Geophysics of Petrovera Resources Limited January 1999 to March 2004 and most recently Exploration Manager of the Company March 2004 to November 2006.
Lynn M. Zeidler Calgary, Alberta Canada	Vice-President, Bitumen Production (age 50)	Officer of the Company since August 2003; prior thereto held progressively senior positions at Shell Canada Limited including on secondment from Shell Canada Limited as Manager-Tier 1 Implementation at Sable Offshore Energy Inc to September 2000 and most recently General Project Manager, Athabasca Oil Sands Project at Shell Canada Limited October 2000 to May 2003 and concurrently as Vice President & Project Director, Muskeg River Mine at Albian Sands Energy Inc. May 2002 to July 2003 and General Manager Claims Athabasca Oil Sands Project at Shell Canada Limited May 2003 to July 2003.
Bruce E. McGrath Calgary, Alberta Canada	Corporate Secretary (age 57)	Officer of the Company.

</TABLE>

(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 Health, Safety, and Environmental Committee

All directors stand for election at each Annual General Meeting of Canadian Natural shareholders. With the exception of Messrs. S. W. Laut and F. J. McKenna who were appointed to the Board effective August 1, 2006, all of the current directors were elected to the Board at the last annual meeting of shareholders held on May 4, 2006. All of the current directors are standing for election at the Annual Special Meeting of Shareholders scheduled for May 3, 2007.

As at December 31, 2006, the directors and officers of the Company, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, in the aggregate, approximately 4 per cent of the total outstanding common shares (approximately 5 per cent after the exercise of options held by them pursuant to the Company's stock option plan).

CONFLICTS OF INTEREST

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).

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, executive officer or principal shareholder of Canadian Natural, or associate or affiliate of those persons, has any material interest, direct or indirect, in any transaction within the last three years that has materially affected or will materially affect the Company.

AUDIT COMMITTEE INFORMATION

AUDIT COMMITTEE MEMBERS

The Audit Committee of the Board of Directors of the Company is comprised of Ms. C. M. Best, Chair, Messrs. G. A. Filmon, G. D. Giffin and D. A. Tuer each of whom is independent and financially literate as those terms are defined under Canadian securities regulations MI 52-110 and the NYSE listing standards as they pertain to audit committees of listed issuers. The education and experience of each member of the Audit Committee relevant to their responsibilities as an Audit Committee member is described below.

Ms. C. M. Best is a chartered accountant with 20 years experience as a staff member and partner of an international public accounting firm. During her tenure she was responsible for direct oversight and supervision of a large staff of auditors conducting audits of the financial reporting of significant publicly traded entities, many of which were oil and gas companies. This oversight and supervision required Ms. C. M. Best to maintain a current understanding of generally accepted accounting principles, and be able to assess their application in each of her clients. It also required an understanding of internal controls and financial reporting processes and procedures.

Honourable G. A. Filmon holds both a Bachelor of Science degree and a Master of Science degree in Civil Engineering. He was Premier of the Province of Manitoba for several years and during that time chaired the Treasury Board for a period of five years. He was President of Success Commercial College for 11 years and is currently a business management consultant. Mr. G. A. Filmon is a director of other public companies and is an active member of other audit committees, one of which he chairs.

Ambassador G. D. Giffin's education and experience relevant to the performance of his responsibilities as an audit committee member is derived from a thirty-year law practice involving complex accounting and audit-related issues associated with complicated commercial transactions and disputes. He has developed extensive practical experience and an understanding of internal controls and procedures for financial reporting from his service on audit committees for several publicly traded issuers and continues pursuit of extensive professional reading and study on related subjects.

Mr. D. A. Tuer's education and experience relevant to the performance of his responsibilities as an audit committee member is derived from professional training and a business career as a chief executive officer in a large publicly traded company which provided experience in analyzing and evaluating financial statements and supervising persons engaged in the preparation, analysis and evaluation of financial statements of publicly traded companies. He has gained an understanding of internal controls and procedures for financial reporting through oversight of those functions, and the understanding of Audit Committee functions through his years of chief executive involvement.

The Audit Committee in 2006 approved specified audit and non-audit services to be performed by PricewaterhouseCoopers LLP ("PwC") the independent auditor of the Corporation.

AUDITOR SERVICE FEES

The Audit Committee of the Board of Directors in 2006 approved specified audit and non-audit services to be performed by PwC. The services provided include: (i) the annual audit of the Corporation's internal controls and December 31, 2006 consolidated financial statements included in the Annual Information Form and Form 40-F, reviews of the Corporation's unaudited first, second, and third

quarter interim Consolidated Financial Statements, audits of certain of the Corporation's subsidiary companies' annual financial statements as well as other audit services provided in connection with statutory and regulatory filings; (ii) audit related services related to debt covenant compliance, Crown Royalty Statements; (iii) tax related services related to expatriate personal tax and compliance as well as other corporate tax return matters; and (iv) non-audit services related to accessing resource materials through PwC's accounting literature library.

Fiscal 2006 fees accrued to PwC will not exceed those amounts shown in the table below.

AUDITOR SERVICE	2006	2005
Audit fees	$3,126,287	$1,227,835
Audit related fees	$121,353	$266,923
Tax related fees	$134,025	$39,331
All other fees	$9,516	$7,290
	$3,391,181	$1,541,379

The Charter of the Audit Committee of the Company is attached as Schedule "C" to this Annual Information Form.

LEGAL PROCEEDINGS

From time to time, Canadian Natural is the subject of litigation arising out of the Company's operations. Damages claimed under such litigation may be material or may be indeterminate and the outcome of such litigation may materially impact the Company's financial condition or results of operations. While the Company assesses the merits of each lawsuit and defends itself accordingly, the Company may be required to incur significant expenses or devote significant resources to defend itself against such litigation. The claims that have been made to date are not currently expected to have a material impact on the Company's financial position.

MATERIAL CONTRACTS

Other than contracts entered into in the ordinary course of business, the Company has not entered into any material contracts in the most recently completed financial year nor has it entered into any material contracts before the most recently completed financial year and which are still in effect.

INTERESTS OF EXPERTS

PricewaterhouseCoopers LLP, Chartered Accountants, are the Company's auditors and such firm has prepared an opinion with respect to the Company's consolidated financial statements as at and for the year ended December 31, 2006. PricewaterhouseCoopers LLP is independent in accordance with the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta.

Based on information provided by the relevant persons or companies, there are beneficial interests, direct or indirect, in less than 1% of the Company's securities or property or securities or property of our associates or affiliates held by Sproule Associates Limited, Ryder Scott Company or GLJ Petroleum Consultants Ltd. or any partners, employees or consultants of such independent reserves evaluators who participated in and who were in a position to directly influence the preparation of the relevant report, or any such

person who, at the time of the preparation of the report was in a position to directly influence the outcome of the preparation of the report.

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on the SEDAR website at www.sedar.com

Additional information including Directors' and Executive Officers' remuneration and indebtedness, 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 and Special Meeting and Information Circular dated March 14, 2007 in connection with the Annual and Special Meeting of Shareholders of Canadian Natural to be held on May 3, 2007 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, comparative Consolidated Financial Statements and Supplementary Oil & Gas Information for the most recently completed fiscal year ended December 31, 2006 found on pages 42 to 71, 72 to 98 and 99 to 103 respectively, of the 2006 Annual Report to the Shareholders, which information is incorporated herein by reference.

For additional copies of this Annual Information Form, please contact:

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

SCHEDULE "A"

AMENDED FORM 51-101F2
REPORT ON RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

REPORT ON RESERVES DATA

To the Board of Directors of Canadian Natural Resources Limited (the "Corporation"):

1. We have evaluated the Corporation's reserves data as at December 31, 2006. The reserves data consist of the following:

(a) (i) proved conventional crude oil, natural gas liquids and natural gas reserve quantities estimated as at December 31, 2006 using constant prices and costs;

(ii) the related estimated net present value; and

(iii) the related standardized measure calculation for proved conventional crude oil, natural gas liquids and natural gas reserve quantities.

(b) (i) both proved, and proved and probable conventional crude oil, natural gas liquids and natural gas reserve quantities estimated as at December 31, 2006 using forecast prices and costs; and

(ii) the related estimated net present value.

(c) (i) both proved, and proved and probable bitumen and synthetic crude oil reserve quantities relating to surface mineable oil sands projects estimated as at December 31, 2006.

2. The reserves data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGEH") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society) with the necessary modifications to reflect definitions and standards under the U.S. Financial Accounting Standards Board policies (the "FASB Standards") and the legal requirements of the U.S. Securities and Exchange Commission ("SEC Requirements").

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions as outlined above.

5. The following table sets forth the estimated net present value of conventional reserves (before deduction of income taxes) attributed to proved conventional crude oil, NGL and natural gas reserves quantities, estimated using constant prices and costs and calculated

using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated by us for the year ended December 31, 2006 except as noted in 1(c)(i), and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's management and board of directors:

<TABLE>
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INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR	DESCRIPTION AND DATE OF PREPARATION EVALUATION REPORT	LOCATION OF RESERVES (COUNTRY OR FOREIGN GEOGRAPHIC AREA)	NET PRESENT VALUES OF CONVENTIONAL RESERVES (BEFORE INCOME TAXES, 10% DISCOUNT RATE) AUDITED MM$	EVALUATED MM$	REVIEWED MM$	TOTAL MM$
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Sproule Associates Ltd.	Sproule Evaluated the P&NG Reserves as reported February 5th, 2007.	Canada, USA	$0	$20,260	$0	$20,260
Ryder Scott Company	Ryder Scott Evaluated the P&NG Reserves as reported February 5th, 2007.	United Kingdom and Offshore West Africa	$0	$7,237	$0	$7,237
TOTALS			$0	$27,497	$0	$27,497

</TABLE>

In addition, both proved, and proved and probable reserves have been evaluated for oil sands mining properties located in Canada. The Horizon Project reserves were evaluated as at December 31, 2006. GLJ Petroleum Consultants Ltd. ("GLJ"), an independent qualified reserves evaluator, was retained by the Reserves Committee of Canadian Natural's Board of Directors to evaluate reserves associated with the Horizon Project incorporating both the mining and upgrading projects. These reserves were evaluated under SEC Industry Guide 7 and are disclosed separately from the Company's conventional crude oil and natural gas activities.

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook as modified by the FASB Standards and SEC requirements. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our evaluation for events and circumstances occurring after their respective preparation dates.

8. Reserves are estimates only, and not exact quantities. In addition, as the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above: February 5th, 2007

SPROULE ASSOCIATES LIMITED

ORIGINAL SIGNED BY:

Harry J. Helwerda, P.Eng.,
Senior Vice-President, Engineering,

ORIGINAL SIGNED BY:

Doug Ho, P.Eng.
Vice-President, Engineering, and Director

ORIGINAL SIGNED BY:

Ken H. Crowther, P.Eng.
President, Canada and U.S.

RYDER SCOTT COMPANY

ORIGINAL SIGNED BY:

Jane Tink, P.Eng.,
Senior Vice-President, Engineering

GLJ PETROLEUM CONSULTANTS LTD.

ORIGINAL SIGNED BY:

James H. Willmon, P.Eng.
Vice-President, Corporate Evaluations

SCHEDULE "B"

REPORT OF
MANAGEMENT AND DIRECTORS
ON OIL AND GAS DISCLOSURE

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Canadian Natural Resources Limited (the "Corporation") is responsible for the preparation and disclosure of information with respect to the Corporation's conventional crude oil, natural gas and surface mineable oil sands activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved conventional crude oil, NGLs and natural gas reserve quantities estimated as at December 31, 2006 using constant prices and costs;

(ii) the related estimated net present value; and

(iii) the related standardized measure calculation for proved conventional crude oil, NGL and natural gas reserve quantities; and,

(b) (i) both proved, and proved and probable conventional crude oil, NGLs and natural gas reserve quantities estimated as at December 31, 2006 using forecast prices and costs;

(ii) the related estimated net present value; and,

(c) (i) both proved, and proved and probable bitumen and synthetic crude oil reserve quantities relating to surface mineable oil sands operations estimated as at December 31, 2006.

Sproule Associates Limited, Ryder Scott Company and GLJ Petroleum Consultants Ltd., all independent qualified reserves evaluators have evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The reserves committee (the "Reserves Committee") of the board of directors (the "Board of Directors") of the Corporation has:

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluators;

(b) met with each of the independent qualified reserves evaluators to determine whether any restrictions placed by management affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves Committee of the Board of Directors has reviewed the Corporation's procedures for assembling and reporting other information associated with crude oil and natural gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other crude oil and natural gas and surface mineable oil sands information;

(b) the filing of the reports of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

Reserves data are estimates only, and are not exact quantities. In addition, as the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

"Signed"
Steve W. Laut
President and Chief Operating Officer

"Signed"
Douglas A. Proll
Chief Financial Officer and Senior Vice President, Finance

"Signed"
David A. Tuer
Independent Director and Chair of the Reserve Committee

"Signed"
Norman F. McIntyre
Independent Director and Member of the Reserve Committee

Dated this 3rd day of March, 2007
Calgary, Alberta

SCHEDULE "C"

CANADIAN NATURAL RESOURCES LIMITED
(THE "CORPORATION")

CHARTER OF THE AUDIT COMMITTEE OF THE BOARD OF DIRECTORS

I AUDIT COMMITTEE PURPOSE

The Audit Committee is appointed by the Board of Directors (the "Board") to assist the Board in fulfilling its responsibility for the stewardship of the Corporation in overseeing the business and affairs of the Corporation. The Audit Committee's primary duties and responsibilities are to:

1. ensure that the Corporation's management has designed and implemented an effective system of internal financial controls;

2. monitor and report on the integrity of the Corporation's financial statements, financial reporting processes and systems of internal controls regarding financial, accounting and compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters and disclosure of material facts;

3. select and recommend for appointment by the shareholders, the Corporation's independent auditors, pre-approve all audit and non-audit services to be provided to the Corporation by the Corporation's independent auditors consistent with all applicable laws, and establish the fees and other compensation to be paid to the independent auditors;

4. monitor the independence and performance of the Corporation's independent auditors;

5. monitor the performance of the internal auditing function;

6. establish procedures for the receipt, retention, response to and treatment of complaints, including confidential, anonymous submissions by the Corporation's employees, regarding accounting, internal controls or auditing matters; and,

7. provide an avenue of communication among the independent auditors, management, the internal auditing function and the Board.

II AUDIT COMMITTEE COMPOSITION, PROCEDURES AND ORGANIZATION

1. The Audit Committee shall consist of at least three (3) directors as determined by the Board, each of whom shall be independent, non-executive directors, free from any relationship that would interfere with the exercise of his or her independent judgment. Audit Committee members shall meet the independence and experience requirements of the regulatory bodies to which the Corporation is subject to. All members of the Audit Committee shall have a basic understanding of finance and accounting and be able to read and understand fundamental financial statements at the time of their appointment to the Audit Committee. At least one member of the Audit Committee shall have accounting or related financial management expertise and qualify as a

"financial expert" or similar designation in accordance with the requirements of the regulatory bodies to which the Corporation may be subject to.

2. The Board at its organizational meeting held in conjunction with each annual general meeting of the shareholders shall appoint the members of the Audit Committee for the ensuing year. The Board may at any time remove or replace any member of the Audit Committee and may fill any vacancy in the Audit Committee.

3. The Board shall appoint a member of the Audit Committee as chair of the Audit Committee. If an Audit Committee Chair is not designated by the Board, or is not present at a meeting of the Audit Committee, the members of the Audit Committee may designate a chair by majority vote of the Audit Committee membership.

4. The Secretary or the Assistant Secretary of the Corporation shall be secretary of the Audit Committee unless the Audit Committee appoints a secretary of the Audit Committee.

5. The quorum for meetings shall be one half (or where one half of the members of the Audit Committee is not a whole number, the whole number which is closest to and less than one half) of the members of the Audit Committee subject to a minimum of two members of the Audit Committee present in person or by telephone or other telecommunications device that permits all persons participating in the meeting to speak and to hear each other.

6. Meetings of the Audit Committee shall be conducted as follows:

(a) the Audit Committee shall meet at least four (4) times annually at such times and at such locations as may be requested by the Chair of the Audit Committee;

(b) the Audit Committee shall meet privately in executive sessions at each meeting with management, the manager of internal auditing, the independent auditors, and as a committee to discuss any matters that the Audit Committee or each of these groups believe should be discussed.

7. The independent auditors and internal auditors shall have a direct line of communication to the Audit Committee through its chair and may bypass management if deemed necessary. Any employee may bring before the Audit Committee directly and may bypass management if deemed necessary any matter involving questionable, illegal or improper financial practices or transactions.

III AUDIT COMMITTEE DUTIES AND RESPONSIBILITIES

1. The overall duties and responsibilities of the Audit Committee shall be as follows:

a. to assist the Board in the discharge of its responsibilities relating to the Corporation's accounting principles, reporting practices and internal controls and its approval of the Corporation's annual and quarterly consolidated financial statements;

b. to establish and maintain a direct line of communication with the Corporation's internal auditors and independent auditors and assess their performance;

c. to ensure that the management of the Corporation has designed, implemented and is maintaining an effective system of internal controls;

d. to report regularly to the Board on the fulfillment of its duties and responsibilities; and,

e. to review annually the Audit Committee Charter and recommend any changes to the Nominating and Corporate Governance Committee for approval by the Board.

2. The duties and responsibilities of the Audit Committee as they relate to the independent auditors shall be as follows:

a. to select and recommend to the Board of Directors for appointment by the shareholders, the Corporation's independent auditors, review the independence and monitor the performance of the independent auditors and approve any discharge of auditors when circumstances warrant;

b. to approve the fees and other significant compensation to be paid to the independent auditors, scope and timing of the audit and other related services rendered by the independent auditors;

c. to approve the independent auditor's annual audit plan, including scope, staffing, locations and reliance upon management and internal audit department prior to the commencement of the audit;

d. to pre-approve all proposed non-audit services to be provided by the independent auditors except those non-audit services prohibited by legislation;

e. on an annual basis, obtain and review a report by the independent auditors describing (i) the independent auditor's internal quality control procedures; (ii) any material issues raised by the most recent quality-control review, or peer review, of the firm, or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out by the firm; and, (iii) any steps taken to address any such issues arising from the review, inquiry or investigation, and, receive a written statement from the independent auditors outlining all significant relationships they have with the Corporation that could impair the auditor's independence. The Corporation's independent auditors may not be engaged to perform prohibited activities under the Sarbanes-Oxley Act of 2002 or the rules of the Public Company Accounting Oversight Board or other regulatory bodies, which the Corporation is governed by;

f. to review and discuss with the independent auditors, upon completion of their audit and prior to the filing or releasing annual financial statements:

(i) contents of their report, including:

(a) all critical accounting policies and practices used;

(b) all alternative treatments of financial information within GAAP that have been discussed with management, ramifications of the use of such treatments and the treatment preferred by the independent auditor;

(c) other material written communications between the independent auditor and management;

(ii) scope and quality of the audit work performed;

(iii) adequacy of the Corporation's financial and auditing personnel;

(iv) cooperation received from the Corporation's personnel during the audit;

(v) internal resources used;

(vi) significant transactions outside of the normal business of the Corporation;

(vii) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles or management systems;

(viii) the non-audit services provided by the independent auditors; and,

(ix) consider the independent auditor's judgments about the quality and appropriateness of the Corporation's accounting principles and critical accounting estimates as applied in its financial reporting;

g. to review and approve a report to shareholders as required, to be included in the Corporation's Information Circular and Proxy Statement, disclosing any non-audit services approved by the Audit Committee; and

h. to review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former independent auditor of the Corporation.

3. The duties and responsibilities of the Audit Committee as they relate to the internal auditors shall be as follows:

a. to review the budget, internal audit function with respect to the organization structure, staffing, effectiveness and qualifications of the Corporation's internal audit department;

b. to review and approve the internal audit plan; and

c. to review significant internal audit findings and recommendations together with management's response and follow-up thereto.

4. The duties and responsibilities of the Audit Committee as they relate to the internal control procedures of the Corporation shall be as follows:

a. to review the appropriateness and effectiveness of the Corporation's policies and business practices which impact on the financial integrity of the Corporation, including those relating to internal auditing, insurance, accounting, information services and systems and financial controls, management reporting and risk management;

b. to review any unresolved issues between management and the independent auditors that could affect the financial reporting or internal controls of the Corporation; and,

c. to periodically review the Corporation's financial and auditing procedures and the extent to which recommendations made by the internal audit staff or by the independent auditors have been implemented.

5. Other duties and responsibilities of the Audit Committee shall be as follows:

a. to review the Corporation's unaudited quarterly consolidated financial statements and related Management Discussion & Analysis including the impact of unusual items and changes in accounting principles and estimates, the earnings press releases before disclosure to the public and report to the Board with respect thereto;

b. to review the Corporation's audited annual consolidated financial statements and related Management Discussion & Analysis including the impact of unusual items and changes in accounting principles and estimates, the earnings press releases before disclosure to the public and report to the Board with respect thereto;

c. to ensure adequate procedures are in place for the review of the Corporation's public disclosure of financial information extracted or derived from the Corporation's financial statements, other than the quarterly and annual earnings press releases, and periodically assess the adequacy of those procedures;

d. to review the appropriateness of the policies and procedures used in the preparation of the Corporation's consolidated financial statements and other required disclosure documents and consider recommendations for any material change to such policies;

e. to review with management, the independent auditors and if necessary with legal counsel, any litigation, claim or other contingency, including tax assessments that could have a material affect upon the financial position or operating results of the Corporation and the manner in which such matters have been disclosed in the consolidated financial statements;

f. to establish procedures for:

(i) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, or auditing matters; and

(ii) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters;

g. to co-ordinate meetings with the Reserves Committee of the Corporation, the Corporation's senior engineering management, independent evaluating

engineers and auditors as required and consider such further inquiries as are necessary to approve the consolidated financial statements;

h. to develop a calendar of activities to be undertaken by the Audit Committee for each ensuing year and to submit the calendar in the appropriate format to the Board following each annual general meeting of shareholders;

i. to perform any other activities consistent with this Charter, the Corporation's By-laws and governing law, as the Audit Committee or the Board deems necessary or appropriate; and,

j. to maintain minutes of meetings and to report on a regular basis to the Board on significant results of the foregoing activities.

The Audit Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to the independent auditors as well as officers and employees of the Corporation. The Audit Committee has the authority to retain, at the Corporation's expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties. The Corporation shall at all times make adequate provisions for the payment of all fees and other compensation approved by the Audit Committee, to the Corporation's independent auditors in connection with the issuance of its audit report, or to any consultants or experts employed by the Audit Committee.

Consolidated Balance Sheets

As at December 31 (millions of Canadian dollars)	2006	2005
ASSETS		
Current assets		
Cash and cash equivalents	$ 23	$ 18
Accounts receivable and other	1,947	1,546
Future income tax (note 8)	163	487
Current portion of other long-term assets (note 3)	106	-
	2,239	2,051
Property, plant and equipment (note 4)	30,767	19,694
Other long-term assets (note 3)	154	107
	$ 33,160	$21,852
LIABILITIES		
Current liabilities		
Accounts payable	$ 842	$ 573
Accrued liabilities	1,618	1,781
Current portion of other long-term liabilities (note 6)	611	1,471
	3,071	3,825
Long-term debt (note 5)	11,043	3,321
Other long-term liabilities (note 6)	1,393	1,434
Future income tax (note 8)	6,963	5,035
	22,470	13,615
SHAREHOLDERS' EQUITY		
Share capital (note 9)	2,562	2,442
Retained earnings	8,141	5,804
Foreign currency translation adjustment (note 10)	(13)	(9)
	10,690	8,237
	$ 33,160	$21,852

Commitments and contingencies (note 13)

Approved by the Board of Directors:

/s/ Catherine M. Best
CATHERINE M. BEST
Chair of the Audit Committee and Director

/s/ N. Murray Edwards
N. MURRAY EDWARDS
Vice-Chairman of the Board of Directors and Director

Consolidated Statements of Earnings

For the years ended December 31 (millions of Canadian dollars, except per common share amounts)	2006	2005	2004
Revenue	$ 11,643	$ 11,130	$ 8,269
Less: royalties	(1,245)	(1,366)	(1,011)
Revenue, net of royalties	10,398	9,764	7,258
Expenses			
Production	1,949	1,663	1,400
Transportation and blending	1,443	1,293	972
Depletion, depreciation and amortization	2,391	2,013	1,769
Asset retirement obligation accretion (note 6)	68	69	51
Administration	180	151	125
Stock-based compensation (note 6)	139	723	249
Interest, net	140	149	189
Risk management activities (note 12)	312	1,952	434
Foreign exchange loss (gain)	122	(132)	(91)
6,744	7,881	5,098	
Earnings before taxes	3,654	1,883	2,160
Taxes other than income tax (note 8)	256	194	165
Current income tax (note 8)	222	286	116
Future income tax (note 8)	652	353	474
Net earnings	$ 2,524	$ 1,050	$ 1,405
Net earnings per common share (note 11)			
Basic	$ 4.70	$ 1.96	$ 2.62
Diluted	$ 4.70	$ 1.95	$ 2.60

Consolidated Statements of Retained Earnings

For the years ended December 31 (millions of Canadian dollars)	2006	2005	2004
Balance - beginning of year	$ 5,804	$ 4,922	$ 3,650
Net earnings	2,524	1,050	1,405
Dividends on common shares (note 9)	(161)	(127)	(107)
Purchase of common shares under Normal Course Issuer Bid (note 9)	(26)	(41)	(26)
Balance - end of year	$ 8,141	$ 5,804	$ 4,922

Consolidated Statements of Cash Flows

For the years ended December 31 (millions of Canadian dollars)	2006	2005	2004
Operating activities			
Net earnings	$ 2,524	$ 1,050	$ 1,405
Non-cash items			
Depletion, depreciation and amortization	2,391	2,013	1,769
Asset retirement obligation accretion	68	69	51
Stock-based compensation	139	723	249
Unrealized risk management activities	(1,013)	925	(40)
Unrealized foreign exchange loss (gain)	134	(103)	(94)
Deferred petroleum revenue tax expense (recovery)	37	(9)	(45)
Future income tax	652	353	474
Deferred charges	(2)	(31)	(33)
Abandonment expenditures	(75)	(46)	(32)
Net change in non-cash working capital (note 14)	(679)	(147)	(14)
	4,176	4,797	3,690
Financing activities			
Issue(repayment)of bank credit facilities	6,499	(435)	357
Issue (repayment) of medium-term notes	400	400	(125)
Repayment of senior unsecured notes	-	(194)	(54)
Issue of US dollar debt securities	788	-	830
Repayment of preferred securities	-	(107)	-
Repayment of obligations under capital leases	-	-	(7)
Issue of common shares on exercise of stock options	21	9	24
Dividends on common shares	(153)	(121)	(101)
Purchase of common shares	(28)	(45)	(33)
Net change in non-cash working capital (note 14)	37	19	6
	7,564	(474)	897
Investing activities			
Expenditures on property, plant and equipment	(7,266)	(5,340)	(4,582)
Net proceeds on sale of property, plant and equipment	71	454	7
Net expenditures on property, plant and equipment	(7,195)	(4,886)	(4,575)
Acquisition of Anadarko Canada Corporation (note 2)	(4,641)	-	-
Net proceeds on sale of other assets	-	11	-
Net change in non-cash working capital (note 14)	101	542	(88)
	(11,735)	(4,333)	(4,663)
Increase (decrease) in cash and cash equivalents	5	(10)	(76)
Cash and cash equivalents - beginning of year	18	28	104
Cash and cash equivalents - end of year	$ 23	$ 18	$ 28

Supplemental disclosure of cash flow information (note 14)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(tabular amounts in millions of Canadian dollars, unless otherwise stated)

1. ACCOUNTING POLICIES

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company head-quartered in Calgary, Alberta, Canada. The Company's operations are focused in North America, largely in Western Canada, the United Kingdom portion of 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 produce synthetic crude oil through mining and upgrading 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 ("Canadian GAAP"). A summary of differences between accounting principles in Canada and those generally accepted in the United States ("US GAAP") is contained in note 16.

Signficant accounting policies are summarized as follows:

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and partnerships. A significant portion 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.

(B) 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.

Purchase price allocations, depletion, depreciation and amortization, and amounts used for ceiling test calculations are based on estimates of crude oil and natural gas reserves and commodity prices, production expenses and capital costs required to develop and produce those reserves. Substantially all 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 calculation of asset retirement obligations includes estimates of the future costs to settle the asset retirement obligation, the timing of the cash flows to settle the obligation, and the future infiation rates. The impact of differences between actual and estimated costs, timing and inflation on the consolidated financial statements of future periods could be material.

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

(C) CASH AND CASH EQUIVALENTS

Cash comprises cash on hand and demand deposits. Other investments (term deposits and certificates of deposit) with an original term to maturity at purchase of three months or less are reported as cash equivalents on the balance sheet.

(D) PROPERTY, PLANT AND EQUIPMENT

The Company follows the full cost method of accounting for its conventional crude oil and natural gas properties and equipment as prescribed by Accounting Guideline 16 ("AcG 16") by the Canadian Institute of Chartered Accountants ("CICA"). Accordingly, all costs relating to the exploration for and development of crude 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 the projects are available for their intended use. 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.

Contractual arrangements that meet the definition of a lease are accounted for as capital leases or operating leases as appropriate.

Property acquisition, construction and development costs related to the Company's Horizon Project are not accounted for under the full cost method of accounting and accordingly, are excluded from the Company's Canadian conventional oil and gas cost centre. Construction costs are capitalized separately to each phase of the Horizon Project. The Company will review the recoverability of the carrying amount of the Horizon Project costs if events or

circumstances indicate that the carrying amount may not be recoverable.

(E) DEPLETION, DEPRECIATION AND AMORTIZATION

Substantially all costs related to each country-by-country cost centre 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 and major development projects. Unproved properties are assessed periodically to determine whether impairment has occurred. When proved reserves are assigned or the value of 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. Costs for major development projects, as identified by management, are not subject to depletion until the projects are available for their intended uses. Processing and production facilities are depreciated on a straight-line basis over their estimated lives.

The Company reviews the carrying amount of its crude oil and natural gas properties ("the properties") relative to their recoverable amount ("the ceiling test") for each cost centre at each annual balance sheet date, or more frequently if circumstances or events indicate impairment may have occurred. The recoverable amount is calculated as the undiscounted cash flow from the properties using proved reserves and expected future prices and costs. If the carrying amount of the properties exceeds their recoverable amount, an impairment loss is recognized in depletion equal to the amount by which the carrying amount of the properties exceeds their fair value. Fair value is calculated as the cash flow from those properties using proved and probable reserves and expected future prices and costs, discounted at a risk-free interest rate.

Midstream assets are depreciated on a straight-line basis over their estimated lives. The Company reviews the recoverability of the carrying amount of the midstream assets when events or circumstances indicate that the carrying amount might not be recoverable. If the carrying amount of the midstream assets exceeds their recoverable amount, an impairment loss equal to the amount by which the carrying amount of the midstream assets exceeds their fair value is recognized in depreciation.

Head office capital assets are amortized on a declining balance basis over their estimated useful lives.

(F) CAPITALIZED INTEREST

Following the Board of Directors' approval of Phase 1 of the Horizon Project in 2005, the Company commenced capitalization of construction period interest based on costs incurred and the Company's cost of borrowing. Interest capitalization on Phase 1 will cease once construction is substantially complete and this phase of the Horizon Project is available for its intended use. The Company will continue to capitalize a portion of interest costs related to subsequent phases of the Horizon Project.

(G) DEFERRED CHARGES

Deferred charges primarily 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. Refer to policy note (R) for the effect of new financial instrument policies on deferred charges.

(H) ASSET RETIREMENT OBLIGATIONS

The Company provides for future asset retirement obligations on its resource properties, facilities, production platforms and gathering systems based on current legislation and industry operating practices. The fair values of asset retirement obligations related to property, plant and equipment are recognized as a liability in the period in which they are incurred. Retirement costs equal to the fair value of the asset retirement obligations are capitalized as part of the cost of the associated property, plant and equipment and are amortized to expense through depletion and depreciation over the lives of the respective assets. The fair value of an asset retirement obligation is estimated by discounting the expected future cash flows to settle the asset retirement obligation at the Company's average credit-adjusted risk-free interest rate. In subsequent periods, the asset retirement obligation is adjusted for the passage of time and for changes in the amount or timing of the underlying future cash flows. Actual expenditures are charged against the accumulated asset retirement obligation as incurred.

The Company's pipelines have an indeterminate life and therefore the fair values of the related asset retirement obligations cannot be reasonably determined. The asset retirement obligations for these assets will be recorded in the year in which the lives of the assets are determinable.

(I) FOREIGN CURRENCY TRANSLATION

Foreign operations that are self-sustaining 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 integrated 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. Non-monetary assets and liabilities are translated at the exchange rate 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 assets.

Gains or losses on translation of integrated foreign operations are included in the consolidated statement of earnings. Gains or losses on the translation of foreign currency balances are either recognized in net earnings immediately, or in the foreign currency translation adjustment (note 10) for translation gains or losses for that portion of the US dollar denominated debt designated as a hedge of the net investment in self-sustaining foreign operations.

(J) REVENUE RECOGNITION

Revenue from the production of crude oil and natural gas is recognized when title passes to the customer, delivery has taken place and collection is reasonably assured. The Company assesses customer creditworthiness, both before entering into contracts and throughout the revenue recognition process.

Revenue as reported represents the Company's share and is presented before royalty payments to governments and other mineral interest owners. Revenue, net of royalties represents the Company's share after royalty payments to governments and other mineral interest owners.

(K) TRANSPORTATION AND BLENDING

Transportation and blending costs incurred to transport crude oil and natural gas to customers are recorded as a separate cost in the consolidated statement of earnings.

(L) PRODUCTION SHARING CONTRACTS

Production generated from Offshore West Africa is currently shared under the terms of various Production Sharing Contracts ("PSCs"). Revenues are divided into cost recovery revenues and profit revenues. Cost recovery revenues allow the Company to recover its share and the government's share of capital and operating costs carried by the Company. Profit revenues are allocated to the Company in accordance with its respective equity interest, after a portion has been allocated to the government. Cost recovery and profit revenues are reported as sales revenues. The government's share of revenues attributable to the Company's equity interest, except for income tax, is reported as a royalty expense in accordance with the PSCs.

(M) PETROLEUM REVENUE TAX

The Company accounts for the 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 reserves and anticipated sales prices and costs. The estimated future PRT is then apportioned to accounting periods on the basis of total estimated future operating income. Changes in the estimated total future PRT are accounted for prospectively.

(N) 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 as of 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.

Taxable income from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in a future period. North America current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary depending upon the nature and amount of capital expenditures incurred in Canada in any particular year.

(O) STOCK-BASED COMPENSATION PLANS

The Company accounts for stock-based compensation using the intrinsic value method as the Company's Stock Option Plan (the "Option Plan") provides current employees with the right to elect to receive common shares or direct cash payment in exchange for options surrendered. A liability for potential cash settlements under the Option Plan is accrued over the vesting period of the stock options based on the difference between the exercise price of the stock options and the market price of the Company's common shares and an estimated forfeiture rate. This liability is revalued at each reporting date to reflect changes in the market price of the Company's common shares and actual forfeitures, with the net change recognized in net earnings, or adjusted to capitalized costs during the construction period in the case of the Horizon Project. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares under the Option Plan, consideration paid by employees and any previously recognized liability associated with the stock options are recorded as share capital.

The Company has an employee stock savings plan and a stock bonus plan. Contributions to the employee stock savings plan are recorded as compensation expense at the time of the contribution. Contributions to the stock bonus plan are recognized as compensation expense over the related vesting period.

(P) RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, currency and interest rate exposures. These derivative

financial instruments are not intended for trading or speculative purposes. Changes in fair value of derivative financial instruments formally designated as hedges are not recognized in net earnings until such time as the corresponding gains or losses on the related hedged items are also recognized. Changes in fair

value of derivative financial instruments not formally designated as hedges are recognized in the balance sheet each period with the offset reflected in risk management activities in the consolidated statements of earnings.

The Company formally documents all derivative financial instruments designated as hedging transactions at the inception of the hedging relationship, in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated, both at inception of the hedge and on an ongoing basis.

The Company enters into commodity price contracts to manage anticipated sales of crude oil and natural gas production in order to protect cash flow for capital expenditure programs. All realized and unrealized gains or losses on these contracts are included in risk management activities, regardless of whether or not these contracts have been formally designated as hedges.

The Company enters into interest rate swap agreements to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. Gains or losses on interest rate swap contracts formally designated as hedges are included in interest expense. Gains or losses on non-designated interest rate contracts are included in risk management activities.

The Company enters into cross-currency swap agreements to manage currency exposure on US dollar denominated long-term debt. The cross-currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. Gains or losses on the foreign exchange component of all cross-currency swap contracts are included in risk management activities. Gains or losses on the interest component of cross-currency swap contracts designated as hedges are included in interest expense.

Gains or losses on the termination of derivative financial instruments that have been accounted for as hedges are deferred under other assets or liabilities on the consolidated balance sheets and amortized into 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 unrealized derivative gain or loss is recognized immediately in net earnings. Gains or losses on the termination of financial instruments that have not been accounted for as hedges are recognized in net earnings immediately.

Risk management activities are included in operating activities in the consolidated statements of cash flows.

Refer to policy note (R) for the effect of new accounting standards related to the accounting for risk management activities.

(Q) 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 not accounted for as a liability are used to purchase common shares at the average market price during the year. The Company's Option Plan described in note 9 results in a liability and expense for all outstanding stock options. As such, the potential common shares associated with the stock options are not included in diluted earnings per share. The dilutive effect of other convertible securities is calculated by applying the "if-converted" method, which assumes that the securities are converted at the beginning of the period and that income items are adjusted to net earnings.

(R) RECENTLY ISSUED ACCOUNTING STANDARDS UNDER CANADIAN GAAP

FINANCIAL INSTRUMENTS

Effective January 1, 2007, the Company will adopt the following new accounting standards issued by the CICA relating to the accounting for and disclosure of financial instruments:

o Section 1530 - "Comprehensive Income" introduces the concept of comprehensive income to Canadian GAAP. Comprehensive income is the change in equity (net assets) of the Company during a reporting period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners.

Foreign currency translation adjustment, which is currently a separate component of shareholders' equity, will be recorded as part of accumulated other comprehensive income.

o Section 3251 - "Equity" replaces Section 3250 - "Surplus" and establishes standards for the presentation of equity and changes in equity during a reporting period. Financial statements of prior periods will be restated only for the foreign currency translation adjustment.

o Section 3855 - "Financial Instruments - Recognition and Measurement" prescribes when a financial asset, financial liability, or nonfinancial derivative is to be recognized on the balance sheet as well as its measurement amount. This section also specifies how financial instruments gains and losses are to be presented.

The Company will include all transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability with the fair value of the financial asset or financial liability. These adjustments were previously recorded in deferred charges. Transaction costs included with the fair value of the financial asset or financial liability will be amortized using the effective interest method.

o Section 3865 - "Hedges" replaces Accounting Guideline 13 - "Hedging Relationships" and EIC 128 - "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments" and specifies how hedge accounting is to be applied and what disclosures are necessary when hedge accounting is applied.

Adoption of this standard will require the Company to record all of its derivative financial instruments on the balance sheet at fair value, including those designated as hedges. Designated hedges are currently not recognized on the balance sheet but are disclosed in the notes to the financial statements. The adjustment to recognize the designated hedges on the balance sheet will be recorded as an adjustment to the opening balance of retained earnings or accumulated other comprehensive income, as appropriate.

Subsequently, if the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk are recognized in the consolidated statements of earnings each period. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in comprehensive income each period and are recognized in the consolidated statements of earnings when the hedged item is recognized. Ineffective portions of changes in the fair value of hedging instruments are recognized in net earnings immediately for both fair value and cash flow hedges.

Adoption of these standards will have the following estimated effects on the Company's consolidated balance sheet as at January 1, 2007:

Decrease future income tax asset	$ (62)
Increase current portion of other long-term assets	$ 193
Decrease other long-term assets	$ (16)
Decrease long-term debt	$ (72)
Increase future income tax liability	$ 18
Increase retained earnings	$ 10
Increase foreign currency translation adjustment	$ 13
Increase accumulated other comprehensive income	$ 146

(S) COMPARATIVE FIGURES

Certain figures related to the presentation of gross revenues and gross transportation and blending provided for prior years have been reclassified to conform to the presentation adopted in 2006.

Common share data has been restated to reflect the two-for-one share split in May 2005.

2. BUSINESS COMBINATIONS

ANADARKO CANADA CORPORATION

In November 2006, the Company completed the acquisition of all of the issued and outstanding common shares of Anadarko Canada Corporation ("ACC"), a subsidiary of Anadarko Petroleum Corporation, for net cash consideration of $4,641 million including working capital and other adjustments. Substantially all of ACC's land and production base are located in Western Canada.

The acquisition was accounted for using the purchase method. Operating results from ACC have been consolidated with the results of the Company effective from November 2, 2006, the date of acquisition, and are reported in the North America segment. The preliminary allocation of the net purchase price is subject to change as actual amounts are determined. The preliminary allocation of the net purchase price to assets acquired and liabilities assumed based on their fair values was as follows:

Net purchase price:	
Net cash consideration (1)	$ 4,641
Net purchase price allocated as follows:	
Non-cash working capital deficit assumed and other	$ (105)
Property, plant and equipment	6,249
Long-term debt	(9)
Asset retirement obligation	(56)
Future income tax	(1,438)
$ 4,641	

(1) Net cash consideration was reduced by $88 million to reflect the settlement of US dollar currency forward contracts designated as hedges of the ACC share purchase price.

3. OTHER LONG-TERM ASSETS

	2006	2005
Deferred charges	$ 109	$ 107
Risk management(note 12)	128	-
Other	23	-
	260	107
Less: current portion	106	-
	$ 154	$ 107

4. PROPERTY, PLANT AND EQUIPMENT

	2006			2005		
	Cost	Accumulated depletion and depreciation	Net	Cost	Accumulated depletion and depreciation	Net
Crude oil and natural gas						
North America	$ 31,715	$ 9,836	$ 21,879	$ 22,258	$ 7,948	$ 14,310
North Sea	3,370	1,341	2,029	2,703	1,022	1,681
Offshore West Africa	1,685	481	1,204	1,547	294	1,253
Other	38	14	24	27	14	13
Horizon Project	5,350	-	5,350	2,169	-	2,169
Midstream	263	56	207	251	48	203
Head office	150	76	74	124	59	65
	$ 42,571	$ 11,804	$ 30,767	$ 29,079	$ 9,385	$ 19,694

During the year ended December 31, 2006, the Company capitalized administrative overhead of $41 million (2005 - $41 million, 2004 - $49 million) relating to exploration and development in the North Sea and Offshore West Africa and $456 million (2005 - $236 million, 2004 - $35 million) relating primarily to the Horizon Project in North America.

During the year ended December 31, 2006, the Company capitalized $196 million (2005 -$72 million, 2004 -$nil) in construction period interest costs related to the Horizon Project.

Included in property, plant and equipment are unproved land and major development projects that are not currently subject to depletion or depreciation:

	2006	2005
Crude oil and natural gas		
North America	$ 2,244	$ 1,372
North Sea	24	28
Offshore West Africa	84	182
Other	24	13
Horizon Project	5,350	2,169
	$ 7,726	$ 3,764

The Company has used the following estimated benchmark future prices ("escalated pricing") in its ceiling test prepared in accordance with Canadian GAAP, as at December 31, 2006:

	2007	2008	2009	2010	2011	thereafter	Average annual increase
Crude oil and NGLs							
North America							
WTI at Cushing (US$/bbl)	$ 65.73	$ 68.82	$ 62.42	$ 58.37	$ 55.20		2.0%
Hardisty Heavy 12(degree) API(C$/bbl)	$ 42.98	$ 45.02	$ 40.74	$ 38.03	$ 35.90		2.0%
Edmonton Par (C$/bbl)	$ 74.10	$ 77.62	$ 70.25	$ 65.56	$ 61.90		2.0%
North Sea and Offshore West Africa							
North Sea Brent (US$/bbl)	$ 63.73	$ 66.78	$ 60.34	$ 56.24	$ 53.04		2.0%
Natural gas							
North America							
Henry Hub Louisiana (US$/mmbtu)	$ 7.85	$ 8.39	$ 7.65	$ 7.48	$ 7.63		2.0%
AECO (C$/mmbtu)	$ 7.72	$ 8.59	$ 7.74	$ 7.55	$ 7.72		2.0%

Huntingdon/Sumas (C$/mmbtu)	$ 7.48	$ 8.45	$ 7.60	$ 7.41	$ 7.58	2.0%

</TABLE>

5. LONG-TERM DEBT

<TABLE>
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	2006	2005
<S>	<C>	<C>
Bank credit facilities		
Bankers' acceptances	$ 6,621	$ 122
Medium-term notes		
7.40% unsecured debentures due March 1, 2007	125	125
4.50% unsecured debentures due January 23, 2013	400	-
4.95% unsecured debentures due June 1, 2015	400	400
Senior unsecured notes		
Adjustable rate due May 27, 2009 (2006 - US$93 million, 2005 - US$93 million)	108	108
US dollar debt securities		
7.80% due July 2, 2008 (2006 - US$8 million, 2005 - US$nil)	9	-
6.70% due July 15, 2011 (2006 - US$400 million, 2005 - US$400 million)	466	467
5.45% due October 1, 2012 (2006 - US$350 million , 2005 - US$350 million)	408	408
4.90% due December 1, 2014 (2006 - US$350 million, 2005 - US$350 million)	408	408
6.00% due August 15, 2016 (2006 - US$250 million, 2005 - US$nil)	291	-
7.20% due January 15, 2032 (2006 - US$400 million, 2005 - US$400 million)	466	467
6.45% due June 30, 2033 (2006 - US$350 million, 2005 - US$350 million)	408	408
5.85% due February 1, 2035 (2006 - US$350 million, 2005 - US$350 million)	408	408
6.50% due February 15, 2037 (2006 - US$450 million, 2005 - US$nil)	525	-
	$ 11,043	$ 3,321

</TABLE>

BANK CREDIT FACILITIES

As at December 31, 2006, the Company had in place unsecured bank credit facilities of $7,809 million, comprised of:

- a $100 million demand credit facility;
- a $500 million demand credit facility;
- a 3-year non-revolving syndicated credit facility of $3,850 million;
- a 5-year revolving syndicated credit facility of $1,825 million;
- a 5-year revolving syndicated credit facility of $1,500 million; and
- a (pound)15 million demand credit facility related to the Company's North Sea operations.

The revolving syndicated credit facilities are fully revolving for a period of five years maturing June 2011. Both facilities are extendible annually for one year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date.

In conjunction with the closing of the acquisition of ACC (note 2), the Company executed a $3,850 million, three-year non-revolving syndicated credit facility maturing in October 2009. This facility is subject to certain prepayment requirements up to a maximum of $1,500 million.

During 2006, the Company obtained a $500 million credit facility repayable on demand.

The weighted average interest rate of the bank credit facilities outstanding at December 31, 2006, was 4.8% (2005 - 4.0%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $338 million, including $300 million related to the Horizon Project, were outstanding at December 31, 2006.

MEDIUM-TERM NOTES

In January 2006, the Company issued $400 million of debt securities maturing January 2013, bearing interest at 4.50%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these securities, the Company has $1.6 billion remaining on its $2 billion shelf prospectus filed in August 2005 that allows for the issue of medium-term notes in Canada until September 2007. If issued, these securities will bear interest as determined at the date of issuance.

In May 2005, the Company issued $400 million of debt securities maturing June 2015, bearing interest at 4.95%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

Subsequent to December 31, 2006, the 7.40% unsecured debentures due March 1, 2007 were repaid.

SENIOR UNSECURED NOTES

The adjustable rate senior unsecured notes bear interest at 6.54% and have annual principal repayments of US$31 million commencing in May 2007, through May 2009.

In December 2005, the Company repaid the US$125 million 7.69% senior unsecured

notes due December 19, 2005.

PREFERRED SECURITIES

In September 2005, the Company redeemed the US$80 million 8.30% preferred securities due May 25, 2011 for cash consideration of US$91 million, including an early repayment premium of US$11 million as required under the Note Purchase Program.

US DOLLAR DEBT SECURITIES

In August 2006, the Company issued US$250 million of unsecured notes maturing August 2016 and US$450 million of unsecured notes maturing February 2037, bearing interest at 6.00% and 6.50%, respectively. Concurrently, the Company entered into cross-currency interest-rate swaps to fix the Canadian dollar interest and principal repayment amounts on the US$250 million notes at 5.40% and C$279 million (note 12). Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

In November 2006, the US shelf prospectus, filed in June 2005, was increased from US$2,000 million to US$3,000 million, leaving US$2,300 million available for issue in the United States until July 2007.

Subsequently, on March 12, 2007, the Company priced, for settlement on March 19, 2007, US$2,200 million of unsecured notes under the US shelf prospectus, comprised of US$1,100 million of unsecured notes maturing May 2017 and US$1,100 million of unsecured notes maturing March 2038, bearing interest at 5.70% and 6.25%, respectively. Concurrently, the Company entered into cross-currency interest-rate swaps to fix the Canadian dollar interest and principal repayment amounts on US$1,100 million of unsecured notes due May 2017 at 5.10% and C$1,287 million. The Company also entered into a cross-currency interest-rate swap to fix the Canadian dollar interest and principal repayment amounts on US$550 million of unsecured notes due March 2038 at 5.76% and C$644 million. Net proceeds on the debt issue will be used to repay outstanding amounts under the Company's bank credit facilities.

REQUIRED DEBT REPAYMENTS

Required debt repayments are as follows:

Year	Repayment
2007	$ 161
2008	$ 45
2009	$ 3,876
2010	$ -
2011	$ 466
Thereafter	$ 3,713

No debt repayments are reflected for $2,782 million of revolving bank credit facilities due to the extendable nature of the facilities.

6. OTHER LONG-TERM LIABILITIES

	2006	2005
Asset retirement obligations	$ 1,166	$ 1,112
Stock-based compensation	744	891
Risk management (note 12)	-	885
Other	94	17
	2,004	2,905
Less: current portion	611	1,471
	$ 1,393	$ 1,434

ASSET RETIREMENT OBLIGATIONS

At December 31, 2006, the Company's total estimated undiscounted costs to settle its asset retirement obligations with respect to crude oil and natural gas properties and facilities was approximately $4,497 million (2005 - $3,325 million). Payments to settle these asset retirement obligations will occur on an ongoing basis over a period of approximately 60 years and have been discounted using an average credit-adjusted risk-free interest rate of 6.7%. A reconciliation of the discounted asset retirement obligations is as follows:

	2006	2005	2004
Asset retirement obligations			
Balance - beginning of year	$ 1,112	$ 1,119	$ 897
Liabilities incurred	26	47	53
Liabilities acquired (note 2)	56	-	286
Liabilities settled	(75)	(46)	(32)
Asset retirement obligation accretion	68	69	51
Revision of estimates	(21)	(56)	(86)
Foreign exchange	-	(21)	(50)
Balance - end of year	$ 1,166	$ 1,112	$ 1,119

STOCK-BASED COMPENSATION

The Company recognizes a liability for the potential cash settlements under its Option Plan. The current portion represents the maximum amount of the liability payable within the next twelve month period if all vested options are surrendered for cash settlement.

	2006	2005	2004
Stock-based compensation			
Balance - beginning of year	$ 891	$ 323	$ 171
Stock-based compensation	139	723	249
Cash payment for options surrendered	(264)	(227)	(80)
Transferred to common shares	(101)	(29)	(38)
Capitalized to Horizon Project	79	101	21
Balance - end of year	744	891	323
Less: current portion of stock-based compensation	611	629	243
	$ 133	$ 262	$ 80

7. EMPLOYEE FUTURE BENEFITS

In connection with the acquisition of ACC, the Company assumed obligations to provide defined contribution pension benefits to certain ACC employees continuing their employment with the Company, and defined benefit pension and other post-retirement benefits to former ACC employees, under registered and unregistered pension plans.

The estimated future cost of providing defined benefit pension and other post-retirement benefits to former ACC employees is actuarially determined using management's best estimates of demographic and financial assumptions. The discount rate of 5% used to determine accrued benefit obligations is based on a year end market rate of interest for high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. Company contributions to the defined contribution plan are expensed as incurred.

The benefit obligation under the registered pension plan at December 31, 2006 was $29 million. As required by government regulations, the Company has set aside funds with an independent trustee to meet these benefit obligations. As at December 31, 2006, these plan assets had a fair value of $54 million. The unregistered pension plans are unfunded and have a benefit obligation of $15 million at December 31, 2006.

8. TAXES

TAXES OTHER THAN INCOME TAX

	2006	2005	2004
Current petroleum revenue tax	$ 196	$ 181	$ 190
Deferred petroleum revenue tax	37	(9)	(45)
Provincial capital taxes and surcharges	23	22	20
	$ 256	$ 194	$ 165

INCOME TAX

The provision for income tax is as follows:

	2006	2005	2004
Current income tax			
Current income tax - North America	$ 143	$ 99	$ 101
Current income tax - North Sea	30	155	2
Current income tax -Offshore West Africa	49	32	13
	222	286	116
Future income tax	652	353	474
Income tax	$ 874	$ 639	$ 590

The provision for income tax 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:

	2006	2005	2004
Canadian statutory income tax rate	34.9%	38.0%	39.3%
Income tax provision at statutory rate	$ 1,275	$ 716	$ 849
Effect on income taxes of:			
Non-deductible portion of Canadian crown payments	131	309	221
Canadian resource allowance	(129)	(293)	(270)
Large Corporations Tax	(16)	16	11
Deductible UK petroleum revenue tax	(82)	(65)	(57)
Foreign tax rate differentials	92	(1)	(31)
North America income tax rate changes	(438)	(19)	(66)
UK income tax rate changes	110	-	-
Cote d'Ivoire income tax rate changes	(67)	-	-
Non-taxable portion of foreign exchange	5	(15)	(36)
Attributed Canadian Royalty Income	(27)	(21)	(4)
Other	20	12	(27)
Income tax	$ 874	$ 639	$ 590

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

	2006	2005
Future income tax liabilities		
Property, plant and equipment	$ 6,088	$ 3,960
Timing of partnership items	1,394	1,646
Unrealized foreign exchange gain on long-term debt	93	112
Risk management activities	40	-
Other	13	31
Future income tax assets		
Asset retirement obligations	(487)	(384)
Capital loss carryforwards	(85)	(79)
Attributed Canadian Royalty Income	-	(75)
Stock-based compensation	(232)	(300)
Risk management activities	-	(304)
Deferred petroleum revenue tax	(24)	(59)
Net future income tax liability	6,800	4,548
Less: current portion future income tax asset	(163)	(487)
Future income tax liability	$ 6,963	$ 5,035

During 2006, income tax rate changes resulted in a reduction of future income tax liabilities of approximately $438 million in North America, an increase of future income tax liabilities of approximately $110 million in the UK North Sea and a reduction of future income tax liabilities of approximately $67 million in Cote d'Ivoire.

During 2005, North America income tax rate changes resulted in a reduction of future income tax liabilities of approximately $19 million.

During 2004, North America income tax rate changes resulted in a reduction of future income tax liabilities of approximately $66 million.

During 2003, the Canadian Federal Government enacted legislation to change the taxation of resource income. The legislation reduces the corporate income tax rate on resource income from 28% to 21% over five years beginning January 1, 2003. Over the same period, the deduction for resource allowance is being phased out and a deduction for actual crown royalties paid is being phased in.

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

	2006		2005	
Common shares	Number of Shares (thousands)	Amount	Number of Shares (thousands)	Amount
Balance - beginning of year	536,348	$ 2,442	536,361	$ 2,408
Issued upon exercise of stock options	2,040	21	837	9
Previously recognized liability on stock options exercised for common shares	-	101	-	29
Purchase of common shares under Normal Course Issuer Bid	(485)	(2)	(850)	(4)
Balance - end of year	537,903	$ 2,562	536,348	$ 2,442

NORMAL COURSE ISSUER BID

During 2006, the Company purchased 485,000 common shares for cancellation (2005 - - 850,000 common shares, 2004 - 1,746,800 common shares) at an average price of $57.33 per common share (2005 - $53.29 per common share, 2004 -$19.00 per common share), for a total cost of $28 million (2005 - $45 million, 2004 -$33 million). Retained earnings was reduced by $26 million (2005 - $41 million, 2004 -$26 million), representing the excess of the purchase price of the common shares over their average carrying value.

In January 2007, the Company renewed its Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the 12-month period beginning January 24, 2007 and ending January 23, 2008, up to 26,941,730 common shares or 5% of the outstanding common shares of the Company then outstanding on the date of the announcement. As at March 15, 2007, the Company had not purchased any additional shares under the Normal Course Issuer Bid.

DIVIDEND POLICY

The Company has paid regular quarterly dividends in January, April, July and October of each year since 2001. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

In March 2007, the Board of Directors set the Company's regular quarterly dividend at $0.085 per common share (2006 - $0.075 per common share, 2005 - $0.059 per common share).

SHARE SPLIT

The Company's shareholders approved a subdivision or share split of its issued and outstanding common shares on a two-for-one basis at the Company's Annual and Special Meeting held on May 5, 2005. All common share and per common share amounts were restated to retroactively reflect the share split.

STOCK OPTIONS

The Company's Option Plan provides for granting of stock options to employees. Stock options granted under the Option Plan have terms ranging from five to six years to expiry and vest equally over a five-year period. The exercise price of each stock option granted is determined at the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the grant. Each stock option granted provides the holder the choice to purchase one common share of the Company at the stated exercise price or receive a cash payment equal to the difference between the stated exercise price and the market price of the Company's common shares on the date of surrender.

The following table summarizes information relating to stock options outstanding at December 31, 2006 and 2005:

	2006		2005	
	Stock Options (thousands)	Weighted Average Exercise Price	Stock options (thousands)	Weighted average exercise price
Outstanding - beginning of year	30,510	$ 17.79	32,522	$ 12.37
Granted	13,084	$ 59.61	7,959	$ 32.51
Exercised for common shares	(2,040)	$ 10.67	(837)	$ 9.81

Surrendered for cash settlement	(5,180)	$ 12.60	(7,523)	$ 10.49
Forfeited	(1,949)	$ 37.51	(1,611)	$ 19.36
Outstanding - end of year	34,425	$ 33.77	30,510	$ 17.79
Exercisable - end of year	9,177	$ 14.73	8,677	$ 11.21

</TABLE>

The range of exercise prices of stock options outstanding and exercisable at December 31, 2006 is as follows:

<TABLE>
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Stock Options Outstanding			Stock Options Exercisable	
Range of exercise prices	Stock Options (thousands)	Weighted Average Remaining Term (years)	Weighted Average Exercise Price	Stock Options Exercisable (thousands)	Weighted Average Exercise Price
<S>	<C>	<C>	<C>	<C>	<C>
$9.63 - $9.99	4,672	0.76	$ 9.71	3,603	$ 9.74
$10.00 - $19.99	9,807	2.20	$ 14.68	4,202	$ 13.78
$20.00 - $29.99	5,099	3.34	$ 25.41	957	$ 25.00
$30.00 - $39.99	1,227	3.79	$ 33.23	175	$ 33.24
$40.00 - $49.99	686	5.02	$ 46.50	69	$ 43.84
$50.00 - $59.99	7,033	4.81	$ 57.85	166	$ 55.14
$60.00 - $69.14	5,901	4.27	$ 61.70	5	$ 61.60
	34,425	3.17	$ 33.77	9,177	$ 14.73

</TABLE>

10. FOREIGN CURRENCY TRANSLATION ADJUSTMENT

The foreign currency translation adjustment represents the unrealized loss on the Company's net investment in self-sustaining foreign operations. Commencing 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, translation gains and losses on this US dollar denominated debt are included in the foreign currency translation adjustment.

	2006	2005
Balance - beginning of year	$ (9)	$ (6)
Unrealized loss on translation of net investment	(4)	(12)
Hedge of net investment with US dollar denominated debt, net of tax	-	9
Balance - end of year	$ (13)	$ (9)

11. NET EARNINGS PER COMMON SHARE

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

(thousands of shares)	2006	2005	2004(1)
Weighted average common shares outstanding - basic	537,339	536,650	536,223
Assumed settlement of preferred securities with common shares(2)	-	1,775	4,461
Weighted average common shares outstanding - diluted	537,339	538,425	540,684
Net earnings	$ 2,524	$ 1,050	$ 1,405
Interest on preferred securities, net of tax(2)	-	4	5
Revaluation of preferred securities, net of tax (2)	-	(2)	(4)
Diluted net earnings	$ 2,524	$ 1,052	$ 1,406
Net earnings per common share			
Basic	$ 4.70	$ 1.96	$ 2.62
Diluted	$ 4.70	$ 1.95	$ 2.60

(1) Restated to reflect two-for-one share split in May 2005.
(2) The preferred securities were redeemed in September 2005.

12. FINANCIAL INSTRUMENTS

RISK MANAGEMENT

On January 1, 2004, the fair values of all outstanding derivative financial instruments that were not designated as hedges for accounting purposes were recorded on the consolidated balance sheet, with an offsetting net deferred revenue amount. Subsequent net changes in the fair value of non-designated financial instruments have been recognized on the consolidated balance sheet and in net earnings. The estimated fair value for all derivative financial instruments is based on third party indications.

As at December 31, 2006 and 2005, the estimated fair values of non-designated financial derivatives were comprised as follows:

<TABLE>
<CAPTION>

	2006		2005	
Asset (liability)	Risk Management Mark-to-Market	Deferred Revenue	Risk Management Mark-to-Market	Deferred Revenue
<S>	<C>	<C>	<C>	<C>
Balance - beginning of year	$ (877)	$ (8)	$ 66	$ (26)
Net cost of outstanding put options	455	-	190	-
Net change in fair value of outstanding derivative financial instruments	1,005	-	(943)	-
Amortization of deferred revenue	-	8	-	18
	583	-	(687)	(8)
Add: put premium financing obligations (1)	(455)	-	(190)	-
Balance - end of year	128	-	(877)	(8)
Less: current portion	88	-	(834)	(8)
	$ 40	$ -	$ (43)	$ -

</TABLE>

(1) The Company has negotiated payment of put option premiums with various counter-parties at the time of actual settlement of the respective options. These obligations have been reflected in the net risk management asset (liability).

Net losses (gains) from risk management activities for the years ended December 31 were as follows:

	2006	2005	2004
Net realized risk management loss	$ 1,325	$ 1,027	$ 474
Net unrealized risk management (gain) loss	(1,013)	925	(40)
	$ 312	$ 1,952	$ 434

As at December 31, 2006, the net unrecognized asset related to the estimated fair values of derivative financial instruments designated as hedges was $222 million (December 31, 2005 - net unrecognized liability of $990 million).

FINANCIAL CONTRACTS

The Company's financial instruments recognized in the consolidated balance sheets consist of cash and cash equivalents, accounts receivable, accounts payable, accrued liabilities, risk management activities, stock-based compensation, and long-term debt.

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

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

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

	2006		2005	
Asset (liability)	Carrying Value	Fair Value	Carrying Value	Fair Value
Derivative financial instruments	$ 583	$ 805	$ (687)	$(1,700)
Fixed rate notes	$ (4,410)	$ (4,434)	$ (3,199)	$(3,367)

COMMODITY PRICE RISK MANAGEMENT

The Company uses certain derivative financial instruments to manage its commodity price exposures. These financial instruments are entered into solely for hedging purposes and are not intended for trading or other speculative purposes. The following summarizes instruments outstanding as at December 31, 2006:

<TABLE>
<CAPTION>

Remaining term	Volume	Average price	Index
<S>	<C>	<C>	<C>
Crude oil			
Crude oil price collars	Jan 2007 - Dec 2007	15,000 bbl/d	US$50.00 - US$66.25 Mayan Heavy
Jan 2007 - Dec 2007	50,000 bbl/d	US$60.00 - US$71.49	WTI
Jan 2007 - Dec 2007	100,000 bbl/d	US$60.00 - US$78.11	WTI
Jan 2007 - Dec 2007	50,000 bbl/d	US$65.00 - US$84.52	WTI
Jan 2008 - Dec 2008	50,000 bbl/d	US$60.00 - US$76.05	WTI
Jan 2008 - Dec 2008	50,000 bbl/d	US$60.00 - US$76.98	WTI
Crude oil puts (1)	Jan 2007 - Dec 2007	100,000 bbl/d	US$45.00 WTI
Jan 2007 - Dec 2007	100,000 bbl/d	US$60.00	WTI
Jan 2008 - Dec 2008	50,000 bbl/d	US$55.00	WTI
Brent differential swaps	Jan 2007 - Dec 2007	50,000 bbl/d	US$1.34 WTI/Dated Brent

</TABLE>

The cost of outstanding put options and their respective years of settlement are as follows:

	2007	2008
Cost (1) ($ millions)	US$ 331	US$ 59

(1) Subsequent to December 31, 2006, the Company unwound 23,000 bbl/d of US$60.00 WTI put options for the period February 2007 to December 2007, for cash consideration of US$40 million.

<TABLE>
<CAPTION>

Remaining term	Volume	Average price	Index
<S>	<C>	<C>	<C>
Natural gas			
AECO collars	Jan 2007 - Mar 2007	100,000 GJ/d	C$7.00 - C$11.63 AECO
Jan 2007 - Mar 2007	200,000 GJ/d	C$7.25 - C$8.38	AECO
Jan 2007 - Mar 2007	162,500 GJ/d	C$7.25 - C$9.48	AECO
Jan 2007 - Mar 2007	162,500 GJ/d	C$7.50 - C$8.94	AECO
Jan 2007 - Mar 2007	300,000 GJ/d	C$7.50 - C$18.77	AECO
Jan 2007 - Mar 2007	400,000 GJ/d	C$8.50 - C$11.22	AECO
Jan 2007 - Dec 2007	60,000 GJ/d	C$8.00 - C$8.79	AECO
Apr 2007 - Oct 2007	500,000 GJ/d	C$6.00 - C$10.13	AECO
Apr 2007 - Oct 2007	500,000 GJ/d	C$7.00 - C$8.24	AECO
Nov 2007 - Mar 2008	400,000 GJ/d	C$7.00 - C$14.08	AECO
Nov 2007 - Mar 2008	500,000 GJ/d	C$7.50 - C$10.81	AECO

</TABLE>

Commodity related derivative financial instruments designated as hedges at December 31, 2006, were all classified as cash flow hedges.

The Company's outstanding derivatives will be settled monthly based on the applicable index pricing for the respective contract month.

In addition to the financial derivatives noted above, the Company also entered into natural gas physical sales contracts for 325,000 GJ/d at an average fixed price of C$9.17 per GJ at AECO for the period January to March 2007 and 300,000 GJ/d at an average fixed price of C$7.33 per GJ at AECO for the period April 2007 to October 2007.

As at December 31, 2006, the net unrealized loss related to the de-designation of commodity cash flow hedges was $41 million. This unrealized loss will be recognized in earnings in 2007.

INTEREST RATE RISK MANAGEMENT

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow-risk on its fioating rate long-term debt. The Company enters into interest rate swap agreements to manage its fixed to fioating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At December 31, 2006, the Company had the following interest rate swap contracts outstanding:

<TABLE>
<CAPTION>

Remaining Term	Amount ($ millions)	Fixed Rate	Floating Rate
<S>	<C>	<C>	<C> <C>
Interest rate			

Swaps - fixed to floating	Jan 2007 - Oct 2012	US$350	5.45%	LIBOR (1) + 0.81%
Jan 2007 - Dec 2014	US$350	4.90%	LIBOR (1) + 0.38%	
Swaps - floating to fixed	Jan 2007 - Mar 2007	C$2	7.36%	CDOR (2)

- ----------

</TABLE>

(1) London Interbank Offered Rate
(2) Canadian Deposit Overnight Rate

Interest rate related derivative financial instruments designated as hedges at December 31, 2006, were all classified as fair value hedges.

FOREIGN CURRENCY EXCHANGE RATE RISK MANAGEMENT

The Company is exposed to foreign exchange rate risk in Canada on its US dollar denominated debt and on product sales based on US dollar denominated benchmarks. The Company is also exposed to foreign exchange rate risk on transactions conducted in foreign currencies in its foreign subsidiaries and in the carrying value of its self-sustaining foreign subsidiaries. The Company enters into cross-currency swap agreements to manage currency exposure on US dollar denominated long-term debt. The cross-currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. The Company may also enter into foreign currency denominated financial contracts to manage future US dollar denominated crude oil and natural gas sales. The Company has designated certain US dollar denominated debt as a hedge against its net investment in US dollar-based self-sustaining foreign operations (note 10). At December 31, 2006, the Company had the following cross-currency swap contracts outstanding:

Remaining Term	Amount ($ Millions)	Exchange Rate(US$/C$)	Interest Rate(US$)	Interest Rate(C$)
Currency Swaps	Jan 2007 - Aug 2016	US$250	1.116	6.00%	5.40%

Cross-currency related derivative financial instruments designated as hedges at December 31, 2006, were all classified as cash flow hedges.

COUNTERPARTY CREDIT RISK MANAGEMENT

Accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages this risk by only entering into sales contracts with 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 possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by only entering into agreements with highly rated financial institutions and other entities. At December 31, 2006, the Company had net risk management assets of $161 million with specific counterparties related to derivative financial instruments.

13. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2007	2008	2009	2010	2011	Thereafter
Product transportation and pipeline (1)	$ 213	$ 193	$ 134	$ 123	$ 99	$1,042
Offshore equipment operating leases (2)	$ 77	$ 52	$ 52	$ 52	$ 50	$ 131
Offshore drilling	$ 73	$ 83	$ 12	$ 12	$ 4	$ 4
Asset retirement obligations (3)	$ 3	$ 3	$ 3	$ 3	$ 4	$4,480
Office leases	$ 26	$ 32	$ 33	$ 34	$ 22	$ -
Electricity and other	$ 51	$ 10	$ 17	$ 18	$ 1	$ -

(1) The Company has entered into a 25 year pipeline transportation agreement commencing in 2008, related to future crude oil production. The agreement is renewable for successive 10-year periods at the Company's option. During the initial term, the annual toll payments before operating costs will be approximately $35 million.

(2) Offshore equipment operating leases are primarily comprised of obligations related to fioating production, storage and offtake vessels ("FPSO"). During 2006, the Company entered into an agreement to lease an additional FPSO commencing in 2008, in connection with the planned offshore development in Gabon, Offshore West Africa. The new FPSO lease agreement contains cancellation provisions at the option of the Company, subject to escalating termination payments throughout 2007 to a maximum of US$395 million.

(3) Amounts represent management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2007 - 2011 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

In 2005, the Board of Directors approved the construction costs for Phase 1 of the Horizon Project, with an approved budget of $6.8 billion. Cumulative construction spending to December 31, 2006 was approximately $4.0 billion. Final construction costs for Phase 1 may differ from the approved budget due to changes in the final scope and timing of completion of the project, and/or inflationary cost pressures.

The Company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The Company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

14. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Changes in non-cash working capital were as follows:

	2006	2005	2004
(Increase) decrease in non-cash working capital			
Accounts receivable and other	$ (116)	$ (498)	$ (329)
Accounts payable	157	196	39
Accrued liabilities	(582)	716	194
Net change in non-cash working capital	$ (541)	$ 414	$ (96)
Relating to:			
Operating activities	$ (679)	$ (147)	$ (14)
Financing activities	37	19	6
Investing activities	101	542	(88)
	$ (541)	$ 414	$ (96)

Other cash flow information:	2006	2005	2004
Interest paid	$ 262	$ 200	$ 192
Taxes paid	$ 703	$ 430	$ 218

15. SEGMENTED INFORMATION

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

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

Midstream activities include the Company's pipeline operations and an electricity co-generation system.

Activities that are not included in the above segments are included in the segmented information as other.

Inter-segment eliminations include internal transportation and electricity charges.

<TABLE>
<CAPTION>

Crude Oil and Natural Gas

	North America			North Sea			Offshore West Africa		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
<S>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>
Segmented revenue	$ 9,066	$ 8,955	$ 6,701	$ 1,616	$ 1,659	$ 1,317	$ 950	$ 485	$ 222
Less: royalties	(1,203)	(1,350)	(1,003)	(3)	(3)	(2)	(39)	(13)	(6)
Revenue, net of royalties	7,863	7,605	5,698	1,613	1,656	1,315	911	472	216
Segmented expenses									
Production	1,436	1,211	976	390	379	370	106	53	36
Transportation and blending	1,465	1,310	978	15	20	32	1	-	-
Depletion, depreciation and amortization	1,897	1,595	1,444	297	306	265	189	104	53
Asset retirement obligation accretion	35	34	28	31	34	22	2	1	1
Realized risk management activities	1,022	870	362	303	157	112	-	-	-
Total segmented expenses	5,855	5,020	3,788	1,036	896	801	298	158	90
Segmented earnings before the following	$ 2,008	$ 2,585	$ 1,910	$ 577	$ 760	$ 514	$ 613	$ 314	$ 126
Non-segmented expenses									
Administration									
Stock-based compensation									
Interest, net									
Unrealized risk management activities									
Foreign exchange loss (gain)									
Total non-segmented expenses									
Earnings before taxes									
Taxes other than income tax									
Current income tax									
Future income tax									
Net earnings									

</TABLE>

<TABLE>
<CAPTION>

	Midstream			Inter-segment elimination and other			Total		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
<S>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>
Segmented revenue	$ 72	$ 77	$ 68	$ (61)	$ (46)	$ (39)	$ 11,643	$ 11,130	$ 8,269
Less: royalties	-	-	-	-	-	-	(1,245)	(1,366)	(1,011)
Revenue, net of royalties	72	77	68	(61)	(46)	(39)	10,398	9,764	7,258
Segmented expenses									
Production	23	24	20	(6)	(4)	(2)	1,949	1,663	1,400
Transportation and blending	-	-	-	(38)	(37)	(38)	1,443	1,293	972
Depletion, depreciation and amortization	8	8	7	-	-	-	2,391	2,013	1,769
Asset retirement obligation accretion	-	-	-	-	-	-	68	69	51
Realized risk management activities	-	-	-	-	-	-	1,325	1,027	474
Total segmented expenses	31	32	27	(44)	(41)	(40)	7,176	6,065	4,666
Segmented earnings before the following	$ 41	$ 45	$ 41	$ (17)	$ (5)	$ 1	3,222	3,699	2,592
Non-segmented expenses									
Administration							180	151	125
Stock-based compensation							139	723	249
Interest, net							140	149	189
Unrealized risk management activities							(1,013)	925	(40)
Foreign exchange loss (gain)							122	(132)	(91)
Total non-segmented expense							(432)	1,816	432
Earnings before taxes							3,654	1,883	2,160
Taxes other than income tax							256	194	165
Current income tax							222	286	116
Future income tax							652	353	474
Net earnings							$ 2,524	$ 1,050	$ 1,405

</TABLE>

CAPITAL EXPENDITURES

<TABLE>
<CAPTION>

2006			2005		
Cash Expenditures	Non-cash and Fair Value Adjustments(1)	Capitalized Costs	Cash Expenditures	Non-cash and Fair Value Adjustments(1)	Capitalized Costs
<S>	<C>	<C>	<C>	<C>	<C>
Crude oil and natural gas					
North America	$ 7,936	$ 1,521	$ 9,457	$ 2,530	$ (22)	$ 2,508
North Sea	646	(14)	632	387	(136)	251
Offshore West Africa	134	1	135	439	27	466
Other	11	-	11	5	-	5
	8,727	1,508	10,235	3,361	(131)	3,230
Horizon Project (2)	3,185	-	3,185	1,499	-	1,499
Midstream	12	-	12	4	-	4
Head office	26	-	26	22	-	22
	$ 11,950	$ 1,508	$ 13,458	$ 4,886	$ (131)	$ 4,755

</TABLE>

(1) Asset retirement obligations, future income tax adjustments on non-tax base assets, and other fair value adjustments.
(2) Cash expenditures for the Horizon Project also include capitalized interest and stock-based compensation.

Segmented property, plant and equipment, net	2006	2005
Crude oil and natural gas		
North America	$ 21,879	$ 14,310
North Sea	2,029	1,681
Offshore West Africa	1,204	1,253
Other	24	13
Horizon Project	5,350	2,169
Midstream	207	203
Head office	74	65
	$ 30,767	$ 19,694

Segmented assets	2006	2005
Crude oil and natural gas		
North America	$ 23,670	$ 15,939
North Sea	2,248	1,950
Offshore West Africa	1,323	1,371
Other	46	30
Horizon Project	5,444	2,239
Midstream	355	258
Head office	74	65
	$ 33,160	$ 21,852

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

The Company's consolidated financial statements have been prepared in accordance with Canadian GAAP. These principles conform in all material respects with US GAAP except for those noted below. Certain 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	2006	2005	2004
Net earnings - Canadian GAAP		$ 2,524	$ 1,050	$ 1,405
Adjustments				
Depletion, net of tax of $1 million (2005 -$3 million, 2004 -$2 million)	(A,C)	2	4	4
Stock-based compensation, net of tax of $18 million (2005 -$nil, 2004 -$nil)	(B)	(40)	-	-
Derivative financial instruments and hedging activities, net of tax of $15 million (2005 -$11 million, 2004 -$7 million)	(C)	117	(19)	(9)
Capitalized interest, net of tax of $nil (2005 -$nil, 2004 -$11 million)	(D)	-	-	16
Net earnings before cumulative effect of change in accounting policy - US GAAP		2,603	1,035	1,416
Cumulative effect of change in accounting policy, net of tax of $3 million (2005 -$nil,2004 -$nil)	(B)	(8)	-	-
Net earnings - US GAAP		$ 2,595	$ 1,035	$ 1,416
Net earnings before cumulative effect of change in accounting policy - US GAAP per common share				
Basic		$ 4.84	$ 1.93	$ 2.64
Diluted	(F)	$ 4.77	$ 1.88	$ 2.57
Net earnings - US GAAP per common share				
Basic		$ 4.83	$ 1.93	$ 2.64
Diluted	(F)	$ 4.75	$ 1.88	$ 2.57

Comprehensive income under US GAAP would be as follows:

(millions of Canadian dollars)	Notes	2006	2005	2004
Net earnings - US GAAP		$ 2,595	$ 1,035	$ 1,416
Derivative financial instruments and hedging activities, net of tax of $394 million (2005 -$312 million; 2004 -$3 million)	(C)	805	(635)	8
Foreign currency translation adjustment, net of tax of $nil (2005 -$2 million, 2004 -$4 million)	(E)	(4)	(3)	(9)
Comprehensive income		$ 3,396	$ 397	$ 1,415

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

2006

(millions of Canadian dollars)	Notes	Canadian GAAP	Increase (Decrease)	US GAAP
Current assets	(C)	$ 2,239	$ 131	$ 2,370
Property, plant and equipment	(A,B,C,D)	30,767	89	30,856
Other long-term assets	(C)	154	29	183
		$ 33,160	$ 249	$ 33,409
Current liabilities	(B)	$ 3,071	$ 30	$ 3,101
Long-term debt	(C)	11,043	(26)	11,017
Other long-term liabilities	(B)	1,393	20	1,413
Future income tax	(A,B,C,D)	6,963	21	6,984
Share capital		2,562	-	2,562
Retained earnings		8,141	45	8,186
Foreign currency translation adjustment	(E)	(13)	13	-
Accumulated other comprehensive income	(C,E)	-	146	146
		$ 33,160	$ 249	$ 33,409

2005

(millions of Canadian dollars)	Notes	Canadian GAAP	Increase (Decrease)	US GAAP
Current assets	(C)	$ 2,051	$ 338	$ 2,389
Property, plant and equipment	(A,D)	19,694	(20)	19,674
Other long-term assets		107	-	107
		$ 21,852	$ 318	$ 22,170
Current liabilities	(C)	$ 3,825	$1,005	$ 4,830
Long-term debt	(C)	3,321	(18)	3,303
Other long-term liabilities	(C)	1,434	8	1,442
Future income tax	(A,C,D)	5,035	(5)	5,030
Share capital		2,442	-	2,442
Retained earnings		5,804	(26)	5,778
Foreign currency translation adjustment	(E)	(9)	9	-
Accumulated other comprehensive income	(C,E)	-	(655)	(655)
		$ 21,852	$ 318	$ 22,170

NOTES:

(A) Under Canadian full cost accounting rules, costs capitalized in each cost centre are limited to an amount equal to the undiscounted, future net revenues from proved reserves using estimated future prices and costs, plus the carrying amount of unproved properties and major development projects (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 based on prices and costs as at the balance sheet date ("constant dollar pricing") and are discounted at 10%. Capitalized costs and future net revenues are determined on a net of tax basis. These differences in applying the ceiling test to prior years resulted in the recognition of a ceiling test impairment under US GAAP, decreasing property, plant and equipment.

For the year ended December 31, 2006, US GAAP net earnings would have increased by $3 million (2005 - $4 million, 2004 - $4 million), net of income taxes of $2 million (2005 - $3 million, 2004 - $2 million) to reflect the impact of lower depletion charges.

(B) The Company accounts for its stock-based compensation liability under Canadian GAAP using the intrinsic value method, as described in note 1(O). Under US GAAP, effective January 1, 2006, the Company would have adopted Financial Accounting Standards Board Statement ("FAS") 123(R), which requires companies to account for all stock-based compensation liabilities using the fair value method, where fair value is measured using an option pricing model. The Company uses the Black Scholes option pricing model to determine the fair value of its stock-based compensation liability for US GAAP purposes. The previous US GAAP standard, FAS 123, required companies to account for cash settled stock-based compensation liabilities using the intrinsic value method. For the year ended December 31, 2006 US GAAP net earnings would have decreased by $48 million, net of income taxes of $21 million, including the cumulative effect of the change in accounting policy of $8 million, net of income taxes of $3 million. There was no difference from Canadian GAAP prior to 2006.

(C) The Company accounts for its derivative financial instruments under Canadian GAAP as described in note 1(P). For US GAAP purposes, FAS 133, "Accounting for Derivative Financial Instruments and Hedging Activities," as amended by FAS 138 and FAS 149, establishes US GAAP accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. Generally, all derivatives, whether designated in hedging

relationships or not, and excluding normal purchases and normal sales, are required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk are recognized in the consolidated statements of earnings each period. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in comprehensive income each period and are recognized in the consolidated statements of earnings when the hedged item is recognized. Therefore, ineffective portions of changes in the fair value of hedging instruments are recognized in net earnings immediately for both fair value and cash flow hedges.

The determination of hedge effectiveness and the measurement of hedge ineffectiveness of cash flow hedges are based on a combination of third party valuations and internally derived valuations. The Company uses these valuations to estimate the fair values of the underlying physical commodity contracts.

For the year ended December 31, 2006, assets would have increased by $160 million (2005 -$338 million), liabilities would have decreased by $9 million (2005 - increased by $997 million), and accumulated other comprehensive income would have increased by $159 million (2005 - decreased by $646 million) as a result of recording all derivative financial instruments at fair value in accordance with US GAAP.

The net earnings associated with realized and unrealized hedge ineffectiveness on derivative contracts designated as cash flow hedges during the year would have been $29 million, net of income taxes of $15 million (2005 - loss of $19 million, net of income taxes of $11 million; 2004 - loss of $9 million, net of income taxes of $7 million). The company estimates that $122 million of after-tax hedging gains will be reclassified from accumulated other comprehensive income to current period earnings within the next twelve month period as a result of forecasted sales occurring.

Under Canadian GAAP, the Company hedged the foreign currency component of the US dollar purchase price of ACC using derivative financial instruments formally designated as cash flow hedges. Under US GAAP, the foreign currency component of a business combination is not eligible for cash flow hedging, and therefore, the $88 million after-tax gain on the derivative financial instruments and related depletion expense of $1 million, net of income taxes of $1 million, would have been included in net earnings.

Accordingly, for the year ended December 31, 2006 US GAAP net earnings would have increased in total by $117 million, net of income taxes of $15 million (2005 - decreased net earnings of $19 million, net of income taxes of $11 million; 2004 - decreased net earnings of $9 million, net of income taxes of $7 million) to reflect the impact of derivative financial instruments.

(D) Under Canadian GAAP, the Company began capitalizing interest on the Horizon Project when the Board of Directors approval was received in 2005. For US GAAP, capitalization of interest on projects constructed over time is mandatory and interest would have been capitalized to the costs of construction beginning in 2004. For the year ended December 31, 2004, $27 million would have been capitalized to property, plant and equipment for US GAAP.

(E) Under US GAAP, exchange losses of $4 million, net of income taxes of $nil (2005 -$3 million, net of income taxes of $2 million; 2004 -$9 million, net of income taxes of $4 million) arising from the translation of self-sustaining foreign operations would have been included in comprehensive income.

(F) Under Canadian GAAP, the Company is not required to include potential common shares related to stock options in the calculation of diluted earnings per share since the Company has recorded the potential settlement of the stock options as a liability. Under US GAAP FAS 128 "Earnings per Share", the Company would have included potential common shares related to stock options in the calculation of diluted earnings per share. For the year ended December 31, 2006, an additional 8,762,000 shares would have been included in the calculation of diluted earnings per share for US GAAP (2005 - 13,593,000 additional shares, 2004 - 10,111,000 additional shares).

(G) Recently issued accounting standards under US GAAP:

UNCERTAIN TAX POSITIONS

In July 2006, the FASB issued Interpretation ("FIN") No. 48 "Accounting for Uncertainty in Tax Positions - an Interpretation of FASB Statement No. 109", effective for fiscal years beginning after December 15, 2006. FIN 48 prescribes thresholds for recognizing the benefits of uncertain tax positions in the financial statements. It also provides guidance on derecognition, classification, interest and penalties, disclosure and transition. The Company is currently assessing the impact of FIN 48 on its consolidated financial statements.

TEN-YEAR REVIEW

<TABLE>
<CAPTION>

Years ended December 31	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
FINANCIAL INFORMATION (Cdn $ millions, except per share amounts)										
<S>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>
Net earnings	2,524	1,050	1,405	1,403	539	639	758	213	31	104
Per share - basic (1)	$ 4.70	$ 1.96	$ 2.62	$ 2.62	$ 1.06	$ 1.32	$ 1.62	$ 0.51	$ 0.08	$ 0.26
Cash flow from operations (2)	4,932	5,021	3,769	3,160	2,254	1,920	1,884	724	444	503
Per share - basic (1)	$ 9.18	$ 9.36	$ 7.03	$ 5.88	$ 4.41	$ 3.96	$ 4.04	$ 1.74	$ 1.12	$ 1.28
Capital expenditures, net of dispositions(including business combinations)	12,025	4,932	4,633	2,506	4,069	1,885	2,823	1,901	610	1,119
Balance Sheet information										
Working capital(deficiency)surplus	(832)	(1,774)	(652)	(505)	(14)	(6)	(77)	36	58	(19)
Property, plant and equipment, net	30,767	19,694	17,064	13,714	12,934	8,766	7,439	4,679	3,135	2,831
Total assets	33,160	21,852	18,372	14,643	13,793	9,290	8,051	4,976	3,329	3,016
Long-term debt	11,043	3,321	3,538	2,748	4,200	2,788	2,573	2,157	1,426	1,136
Shareholders' equity	10,690	8,237	7,324	6,006	4,754	3,928	3,297	1,962	1,317	1,250
SHARE INFORMATION										
Common shares outstanding (thousands)	537,903	536,348	536,361	534,926	535,104	484,804	489,116	445,816	399,236	395,276
Weighted average shares outstanding (thousands)	537,339	536,650	536,223	536,940	511,532	485,200	466,804	415,624	397,324	392,168
Dividends declared per common share	$ 0.30	$ 0.24	$ 0.20	$ 0.15	$ -	$ 0.13	$ 0.10	$ -	$ -	-
Trading statistics (1)										
TSX-C$										
Trading volume (thousands)	508,935	637,992	606,024	590,702	619,316	534,976	567,412	430,460	410,440	402,152
Share Price ($/share)										
High	$ 73.91	$ 62.00	$ 27.58	$ 16.81	$ 13.64	$ 13.09	$ 14.05	$ 9.65	$ 7.88	$ 11.06
Low	$ 45.49	$ 24.28	$ 15.96	$ 11.30	$ 9.40	$ 8.98	$ 7.45	$ 4.95	$ 4.56	$ 7.23
Close	$ 62.15	$ 57.63	$ 25.63	$ 16.34	$ 11.70	$ 9.58	$ 10.38	$ 8.81	$ 5.75	$ 7.65
NYSE -US$										
Trading volume (thousands)	401,909	251,554	125,468	46,916	31,864	20,764	3,172	-	-	-
Share Price ($/share)										
High	$ 64.38	$ 54.05	$ 22.37	$ 12.85	$ 8.72	$ 8.63	$ 9.46	$ -	$ -	$ -
Low	$ 40.29	$ 19.74	$ 11.94	$ 7.32	$ 5.89	$ 5.70	$ 6.19	$ -	$ -	$ -
Close	$ 53.23	$ 49.62	$ 21.39	$ 12.61	$ 7.42	$ 6.10	$ 6.88	$ -	$ -	$ -
RATIOS										
Debt to book capitalization (3)	50.8%	28.7%	33.8%	32.8%	47.1%	41.7%	44.0%	52.4%	52.0%	47.6%
Return on average common shareholders' equity, after tax(3)	26.9%	14.3%	21.4%	25.6%	13.0%	17.7%	28.8%	13.0%	2.4%	8.8%
Daily production before royalties per thousand common shares (boe/d)(1)	10.8	10.3	9.6	8.5	8.2	7.4	6.6	5.0	4.7	4.5
Conventional proved and probable reserves per common share (boe)(1)(4)	6.4	4.8	4.3	4.0	3.3	3.1	2.9	2.4	1.9	1.7
Net asset value per common share(1)(5)	$ 56.41	$ 60.44	$ 33.13	$ 23.35	$ 19.57	$ 16.88	$ 20.54	$ 12.33	$ 8.08	$ 6.80

</TABLE>

(1) Restated to reflect two-for-one share splits in May 2004 and May 2005.

(2) Cash flow from operations is a non-GAAP term that represents net earnings adjusted for non-cash items. The Company evaluates its performance basedonnet earnings and cash flow. Cash flow from operations may not be comparable to similar measures used by other companies.

(3) Refer to the MD&A, page 60, "Liquidity and Capital Resources", for the definitions of these items.

(4) Based upon constant dollar Company gross reserves (before royalties), using year-end common shares outstanding.

(5) Based upon 10% discounted, forecast price pre-tax proved and probable net present values as reported in the Company's AIF for conventional reserves, with $250/acre added for core undeveloped land in 2005 and 2006, $75/acre for all years prior, less long-term debt and existing asset liabilities and adjusted for working capital. See reserves disclosures on pages 37 to 41.

<TABLE>
<CAPTION>

Years ended December 31	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
OPERATING INFORMATION										
Conventional crude oil and NGLs (mmbbl)										
<S>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>
Company gross proved reserves (before royalties)										
North America	1,043	785	695	672	665	644	643	554	284	257
North Sea	299	290	303	222	203	83	102	-	-	-
Offshore West Africa	145	148	125	106	94	61	36	-	-	-
	1,487	1,223	1,123	1,000	962	788	781	554	284	257
Company gross proved and probable reserves (before royalties)										
North America	1,753	1,154	992	977	742	740	731	640	380	329
North Sea	421	417	415	317	277	106	134	-	-	-
Offshore West Africa	223	230	214	187	162	111	46	-	-	-
	2,397	1,801	1,621	1,481	1,181	957	911	640	380	329
Conventional Natural gas (bcf)										
Company gross proved reserves (before royalties)										
North America	4,507	3,378	3,202	3,006	3,048	2,566	2,360	2,183	1,901	1,716
North Sea	37	29	27	62	71	94	91	-	-	-
Offshore West Africa	69	83	81	86	90	69	65	-	-	-
	4,613	3,490	3,310	3,154	3,209	2,729	2,516	2,183	1,901	1,716
Company gross proved and probable reserves (before royalties)										
North America	5,898	4,372	4,100	3,611	3,450	2,915	2,762	2,547	2,211	2,078
North Sea	93	69	57	101	89	118	114	-	-	-
Offshore West Africa	121	127	102	111	120	96	84	-	-	-
	6,112	4,568	4,259	3,823	3,659	3,129	2,960	2,547	2,211	2,078
Total proved reserves (before royalties) (mmboe)	2,256	1,804	1,674	1,526	1,497	1,243	1,200	918	601	543
Total proved and probable reserves (before royalties) (mmboe)	3,416	2,562	2,330	2,118	1,791	1,479	1,404	1,065	749	675
Oil Sands, mining (mmbbl)										
Gross proved and probable reserves (before royalties)										
Bitumen	3,530	3,430	-	-	-	-	-	-	-	-
Synthetic crude oil (1)	2,962	2,878	-	-	-	-	-	-	-	-
Daily production (before royalties)										
Crude oil and NGLs (mbbl/d)										
North America	235	222	206	175	169	167	155	87	76	71
North Sea	60	68	65	57	39	36	17	-	-	-
Offshore West Africa	37	23	12	10	7	3	2	-	-	-
	332	313	283	242	215	206	174	87	76	71
Natural gas (mmcf/d)										
North America	1,468	1,416	1,330	1,245	1,204	906	793	721	673	626
North Sea	15	19	50	46	27	12	1	-	-	-
Offshore West Africa	9	4	8	8	1	-	-	-	-	-
	1,492	1,439	1,388	1,299	1,232	918	794	721	673	626
Total production (before royalties) (mboe/d)	581	553	514	459	421	359	306	207	188	175
Product Pricing										
Average crude oil and NGLs price ($/bbl)	53.65	46.86	37.99	32.66	31.22	23.45	31.89	22.26	11.98	18.99
Average natural gas price ($/mcf)	6.72	8.57	6.50	6.21	3.77	5.45	4.92	2.52	2.11	1.97

</TABLE>

(1) SCO reserves are based upon upgrading of the bitumen reserves. The reserves shown for bitumen and SCO are not additive.

MANAGEMENT'S DISCUSSION & ANALYSIS

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

Certain statements in this document or documents incorporated herein by reference for Canadian Natural Resources Limited (the "Company") may constitute "forward-looking statements" within the meaning of the United States Private Securities 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 "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 or insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the availability and cost of seismic, drilling and other equipment; ability of the Company to complete its capital programs; 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 ability of the Company to attract the necessary labour required to build its projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas; availability and cost of financing; success of exploration and development activities; timing and success of integrating the business and operations of acquired companies; 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); asset retirement obligations; 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, and the Company's course of action would depend upon its assessment of the future considering all information then available. For additional information refer to "Risks and Uncertainties" on page 64.

Disclosure related to future commodity pricing, production volumes, royalties, capital expenditures and other 2007 guidance provided throughout this Management's Discussion and Analysis, including the information provided in the "Outlook" section on pages 69 and 70, constitutes forward looking statements as described above.

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 probably 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 were 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.

Except as required by law, the Company assumes no obligation to update forward-looking statements should circumstances or the Company's estimates or opinions change.

SPECIAL NOTE REGARDING NON-GAAP FINANCIAL MEASURES

Management's Discussion and Analysis ("MD&A") includes references to financial measures commonly used in the crude oil and natural gas industry, such as cash flow from operations, adjusted net earnings from operations and net asset value. These financial measures are not defined by Canadian generally accepted accounting principles ("GAAP") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with Canadian GAAP, as an indication of the Company's performance.

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, 2006. The consolidated financial statements have been prepared in accordance with Canadian 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 where otherwise noted. Common share data has been restated to reflect the two-for-one share split in May 2005. The calculation of barrels of oil equivalent ("boe") is based on a conversion ratio of six thousand cubic feet ("mcf") of natural gas to one barrel ("bbl") of crude oil to estimate relative energy content. This

conversion may be misleading, particularly when used in isolation, since the 6 mcf:1 bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head. Production volumes are the Company's interest before royalties, and realized prices exclude the effect of risk management activities, except where noted otherwise. The following discussion and analysis refers primarily to the Company's 2006 financial results compared to 2005 and 2004, unless otherwise indicated. In addition, this discussion details the Company's capital program and outlook for 2007.

Certain figures related to the presentation of gross revenues and gross transportation and blending expense provided for prior years have been reclassified to conform to the presentation adopted in 2006.

Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2006 and its Annual Information Form for the year ended December 31, 2006, is available on SEDAR at www.sedar.com.

This MD&A is dated March 15, 2007.

ABBREVIATIONS

ACC .....Anadarko Canada Corporation
AECO .....Alberta natural gas reference location
AIF .....Annual Information Form
API .....American Petroleum Institute
ARO .....Asset retirement obligations
BBL .....barrel
BBL/D .....barrels per day
BOE .....barrels of oil equivalent
BOE/D .....barrels of oil equivalent per day
BRENT .....Dated Brent
C$ .....Canadian dollars
FPSO .....Floating Production, Storage and Offtake Vessel
GAAP .....Generally accepted accounting principles
GJ.....gigajoule
HEAVY DIFFERENTIAL .....Heavy crude oil differential from WTI
HORIZON PROJECT .....Horizon Oil Sands Project
MCF .....thousand cubic feet
MMBTU .....million British thermal units
MMCF/D .....million cubic feet per day
NGLS .....Natural gas liquids
NYMEX .....New York Mercantile Exchange
NYSE .....New York Stock Exchange
SCO .....Synthetic light crude oil
SEC .....Securities and Exchange Commission
TSX .....Toronto Stock Exchange
UK .....United Kingdom
US .....United States
US$ .....United States dollars
WTI .....West Texas Intermediate

OBJECTIVE AND STRATEGY

The Company's objective is to increase crude oil and natural gas production, reserves, cash flow and net asset value (1) on a per common share basis through the development of its existing crude oil and natural gas properties and through the discovery and acquisition of new reserves. The Company strives to meet this objective by having a defined growth and value enhancement plan for each of its products and segments. The Company takes a balanced approach to growth and investments and focuses on creating long-term shareholder wealth. The Company allocates its capital by maintaining:

o Balance among its products, namely natural gas, light/medium crude oil, Pelican Lake crude oil (2), primary heavy crude oil and thermal heavy crude oil;

o Balance among near-, mid-and long-term projects;

o Balance among acquisitions, exploitation and exploration; and

o Balance between sources of debt financing and maintenance of a strong balance sheet.

(1) Discounted value of conventional crude oil and natural gas reserves and undeveloped land, less net debt.
(2) Pelican Lake crude oil is 14-17 0 degrees API oil, but receives medium quality crude netbacks due to low production costs and low royalty rates.

The Company's three-phase crude oil marketing strategy includes:

o Blending various crude oil streams with diluents to create more attractive feedstock;

o Supporting and participating in pipeline expansions or new additions; and

o Supporting and participating in projects that will increase the conversion capacity for heavy crude oil.

Operational discipline and cost control are central to the Company. By controlling costs consistently throughout all cycles of the industry, the Company believes that it will achieve continued growth. Cost control is attained by developing area knowledge, by dominating core areas and by maintaining high working interests in its properties.

The Company is committed to maintaining its strong financial position. The Company believes that it has built the necessary financial capacity to complete the Horizon Project while at the same time not compromising the delivery of its conventional crude oil and natural gas growth opportunities. Additionally, the Company's risk management hedge program reduces the risk of volatility in commodity price markets and supports the Company's cash flow for its capital

expenditures program throughout the construction period of the Horizon Project.

Strategic accretive acquisitions like the acquisition of ACC are a key component of the Company's strategy. The Company has used a combination of internally generated cash flows and debt financing to selectively acquire properties generating future cash flows in its core regions. These targeted acquisitions should provide additional free cash flow during the construction years of the Horizon Project while still achieving targeted returns.

Highlights for the year ended December 31, 2006 are as follows:

o Achieved record levels of net earnings;

o Achieved record crude oil and NGLs and natural gas production;

o Achieved its revised annual production guidance for crude oil and NGLs and natural gas;

o Completed the acquisition of ACC for net cash consideration of $4,641 million;

o Completed 57% of Phase 1 construction of the Horizon Project;

o Completed all major 2006 milestones on the Horizon Project before winter's onset;

o Achieved full recovery of the Company's capital investments in the Primrose North and South Fields;

o Received Gabonese Government approval of its development plan for the Olowi PSC offshore Gabon and received Board of Directors sanction for development in November 2006;

o Delivered first oil from West Espoir and completed a successful infill drilling campaign at East Espoir in the Company's Offshore West Africa geographic segment; and

o Purchased 485,000 common shares for a cost of $28 million under the Company's Normal Course Issuer Bid.

<TABLE>
<CAPTION>
NET EARNING AND CASH FLOW FROM OPERATIONS
FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	2006	2005	2004
<S>	<C>	<C>	<C>
Revenue, before royalties (1)	$ 11,643	$ 11,130	$ 8,269
Net earnings	$ 2,524	$ 1,050	$ 1,405
Per common share			
- basic	$ 4.70	$ 1.96	$ 2.62
- diluted	$ 4.70	$ 1.95	$ 2.60
Adjusted net earnings from operations (2)	$ 1,664	$ 2,034	$ 1,405
Per common share			
- basic	$ 3.10	$ 3.79	$ 2.62
- diluted	$ 3.10	$ 3.78	$ 2.60
Cash flow from operations (3)	$ 4,932	$ 5,021	$ 3,769
Per common share			
- basic	$ 9.18	$ 9.36	$ 7.03
- diluted	$ 9.18	$ 9.33	$ 6.98
Dividends declared per common share	$ 0.30	$ 0.236	$ 0.200
Total assets	$ 33,160	$ 21,852	$ 18,372
Total long-term liabilities	$ 19,399	$ 9,790	$ 9,196
Capital expenditures, net of dispositions	$ 12,025	$ 4,932	$ 4,633

</TABLE>

(1) Blending costs previously netted against gross revenues in prior years have been reclassified to transportation and blending expense to conform to the presentation adopted in 2006.

(2) Adjusted net earnings from operations is a non-GAAP term that represents net earnings adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings from operations. The following reconciliation lists the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.

<TABLE>
<CAPTION>

($ millions)	2006	2005	2004
<S>	<C>	<C>	<C>
Net earnings as reported	$ 2,524	$ 1,050	$ 1,405
Stock-based compensation, net of tax (a)	95	481	168
Unrealized risk management (gain) loss, net of tax (b)	(674)	607	(27)
Unrealized foreign exchange loss (gain), net of tax (c)	114	(85)	(75)
Effect of statutory tax rate changes on future income tax liabilities (d)	(395)	(19)	(66)
Adjusted net earnings from operations	$ 1,664	$ 2,034	$ 1,405

</TABLE>

(a) The Company's employee stock option plan provides for a cash payment option. Accordingly, the intrinsic value of the outstanding vested options is recorded as a liability on the Company's balance sheet and periodic changes in the intrinsic value, net of taxes, flow through net earnings, or are capitalized to the Horizon Project.

(b) Derivative financial instruments not designated as hedges are recorded at fair value on the balance sheet, with changes in fair value, net of taxes, flowing through net earnings. The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil and natural gas.

(c) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates and are immediately recognized in net earnings.

(d) All substantively enacted adjustments in applicable income tax rates are applied to underlying assets and liabilities on the Company's consolidated balance sheet in determining future income tax assets and liabilities. The impact of these tax rate changes is recorded in net earnings during the period the legislation is substantively enacted. Income tax rate changes during 2006 resulted in a reduction of future income tax liabilities of approximately $438 million in North America, an increase of future income tax liabilities of approximately $110 million in the UK North Sea and a reduction of future income tax liabilities of approximately $67 million in Offshore West Africa. Jurisdictional income tax rate changes in North America in 2005 resulted in a reduction of future income tax liabilities of $19 million (2004 -$66 million reduction).

(3) Cash flow from operations is a non-GAAP term that represents net earnings adjusted for non-cash items. The Company evaluates its performance based on cash flow from operations. The Company considers cash flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. Cash flow from operations may not be comparable to similar measures presented by other companies.

<TABLE>
<CAPTION>

($ millions)	2006	2005	2004
<S>	<C>	<C>	<C>
Net earnings	$ 2,524	$ 1,050	$ 1,405
Non-cash items:			
Depletion, depreciation and amortization	2,391	2,013	1,769
Asset retirement obligation accretion	68	69	51
Stock-based compensation	139	723	249
Unrealized risk management activities	(1,013)	925	(40)
Unrealized foreign exchange loss (gain)	134	(103)	(94)
Deferred petroleum revenue tax expense (recovery)	37	(9)	(45)
Future income tax	652	353	474
Cash flow from operations	$ 4,932	$ 5,021	$ 3,769

</TABLE>

In 2006, the Company reported record net earnings of $2,524 million compared to net earnings of $1,050 million in 2005 (2004 - $1,405 million). Net earnings for the year ended December 31, 2006 included unrealized after-tax income of $860 million related to the effects of risk management activities, statutory tax rate changes on future income tax liabilities, fluctuations in foreign exchange rates and stock-based compensation expense (2005 - unrealized after-tax expenses of $984 million; 2004 - $nil). Excluding these items, adjusted net earnings from operations for the year ended December 31, 2006 decreased to $1,664 million from $2,034 million in 2005 (2004 - $1,405 million) primarily due to decreased natural gas pricing, increased realized risk management losses, increased production expense and increased depletion, depreciation and amortization expense, and the impact of a stronger Canadian dollar relative to the US dollar. These factors were partially offset by stronger benchmark crude oil pricing and increased crude oil and NGLs and natural gas sales volumes.

Operating results in 2006 were impacted by the acquisition of ACC completed in November 2006. The Company completed the acquisition of ACC, a subsidiary of Anadarko Petroleum Corporation, for net cash consideration of $4,641 million including working capital and other adjustments. Substantially all of ACC's land and production base is located in Western Canada and consists of natural gas weighted assets. The operating results of ACC have been consolidated with the results of the Company effective November 2006. Total production from the ACC properties averaged approximately 67,600 boe/d for the two months of November and December, while natural gas production from the ACC properties averaged approximately 354 mmcf/d.

The Company expects that consolidated net earnings will continue to reflect significant volatility due to the impact of risk management activities, stock-based compensation expense and fluctuations in foreign exchange rates.

The Company's commodity hedging program reduces the risk of volatility in commodity price markets and supports the Company's cash flow for its capital expenditure program throughout the Horizon Project construction period. This program allows for the hedging of up to 75% of the near 12 months budgeted production, up to 50% of the following 13 to 24 months expected production and up to 25% of production expected in months 25 to 48. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. In accordance with the policy, approximately 65% of expected crude oil volumes and approximately 75% of expected natural gas volumes have been hedged for 2007. In addition, 77,000 bbl/d of crude oil volumes are protected by put options for 2007 at a strike price of US$60.00 per barrel. The Company is extending its hedge program into 2008 whereby 150,000 bbl/d of crude oil volumes have been hedged (100,000 bbl/d of price collars with a US$60.00 floor and 50,000 bbl/d of put options with a US$55.00 strike price). In addition, 900,000 GJ/d of natural gas volumes have been hedged through the use of price collars for the first quarter of 2008 (400,000 GJ/d with a floor of $7.00 and 500,000 GJ/d with a floor of $7.50).

As effective as the Company's hedges are against reference commodity prices, a portion of the derivative financial instruments entered into by the Company do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The Company is required to mark-to-market these non-designated hedges based on prevailing forward commodity prices in effect at the end of each reporting period. Accordingly, the unrealized risk management asset reflects, at December 31, 2006, the implied price differentials for the non-designated hedges for future periods. The cash settlement amount of the risk management financial derivative instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their mark-to-market value at December 31, 2006.

Due to the changes in crude oil and natural gas forward pricing, and the reversal of prior year unrealized losses, the Company recorded a net unrealized gain of $1,013 million ($674 million after-tax) on its risk management

activities for the year ended December 31, 2006 (2005 -$925 million unrealized loss, $607 million after-tax; 2004 -$40 million unrealized gain, $27 million after-tax). Mark-to-market unrealized gains and losses do not impact the Company's current cash flow or its ability to finance ongoing capital programs. The Company continues to believe that its risk management program meets its objective of securing funding for its capital projects and does not intend to alter its current strategy of obtaining price certainty for its crude oil and natural gas sales.

The Company also recorded a $139 million ($95 million after-tax) stock-based compensation expense for the year ended December 31, 2006 in connection with the 8% increase in the Company's share price for the year ended December 31, 2006 (Company's share price as at: December 31, 2006 - C$62.15; December 31, 2005 - C$57.63; December 31, 2004 - C$25.63; December 31, 2003 - C$16.34). As required by GAAP, the Company records a liability for potential cash payments to settle its outstanding employee stock options, based on the difference between the exercise price of the stock options and the market price of the Company's common shares, pursuant to a graded vesting schedule. The liability is revalued at each balance sheet date to reflect the changes in the market price of the Company's common shares and the options exercised or surrendered in the year, with the net change recognized in earnings, or capitalized as part of the Horizon Project during the construction period. The stock-based compensation liability reflected the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on December 31, 2006. In years when substantial share price changes occur, the Company's net earnings are subject to significant volatility. The Company utilizes its stock-based compensation plan to attract and retain employees in a competitive environment. All employees participate in this plan.

Cash flow from operations for the year ended December 31, 2006 decreased slightly to $4,932 million ($9.18 per common share) from $5,021 million ($9.36 per common share) in 2005 (2004 - $3,769 million or $7.03 per common share). The decrease was primarily due to decreased natural gas pricing, increased realized risk management losses, increased production expense and the impact of a stronger Canadian dollar relative to the US dollar. These factors were partially offset by stronger benchmark crude oil pricing and increased sales volumes.

In 2006, the Company's average sales price per bbl of crude oil and NGLs increased to $53.65 per bbl from $46.86 per bbl in 2005 (2004 - $37.99 per bbl). The Company's average natural gas price decreased to $6.72 per mcf from $8.57 per mcf in 2005 (2004 - $6.50 per mcf).

Total production of crude oil and NGLs before royalties increased to a record 331,998 bbl/d from 313,168 bbl/d in 2005 (2004 - 282,489 bbl/d). The increase in crude oil and NGLs production primarily reflected increased production from the Company's Primrose thermal projects, the positive results from the Pelican Lake waterflood project, the acquisition of ACC, development of West and East Espoir and the full year's impact of production from the Baobab Field located offshore Cote d'Ivoire. Production from the Baobab Field commenced August 2005.

Total natural gas production before royalties increased to 1,492 mmcf/d from 1,439 mmcf/d in 2005 (2004 - 1,388 mmcf/d). The increase in natural gas production primarily reflected additional natural gas production from the ACC acquisition. The increase was partially offset by the production decrease due to the effects of the Company's strategic reduction in natural gas drilling activity and increased North America crude oil drilling, made in response to sustained low natural gas prices and inflationary cost pressures.

Total crude oil and NGLs and natural gas production volumes before royalties increased to 580,724 boe/d from 552,960 boe/d in 2005 (2004 - 513,835 boe/d).

<TABLE>
<CAPTION>

OPERATING HIGHLIGHTS	2006	2005	2004
<S>	<C>	<C>	<C>
Crude oil and NGLs ($/bbl) (1)			
Sales price (2)	$ 53.65	$ 46.85	$ 37.99
Royalties	4.48	3.97	3.16
Production expense	12.29	11.17	10.05
Netback	$ 36.88	$ 31.72	$ 24.78
Natural gas ($/mcf) (1)			
Sales price (2)	$ 6.72	$ 8.57	$ 6.50
Royalties	1.29	1.75	1.35
Production expense	0.82	0.73	0.67
Netback	$ 4.61	$ 6.09	$ 4.48
Barrels of oil equivalent ($/boe) (1)			
Sales price (2)	$ 47.92	$ 48.77	$ 38.45
Royalties	5.89	6.82	5.37
Production expense	9.14	8.21	7.35
Netback	$ 32.89	$ 33.74	$ 25.73

</TABLE>

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.

SUMMARY OF QUARTERLY RESULTS

The following is a summary of the Company's quarterly results for the most recently completed quarters:

<TABLE>
<CAPTION>
($ millions, except per common share amounts)

2006	TOTAL	DEC 31	SEP 30	JUN 30	MAR 31
<S>	<C>	<C>	<C>	<C>	<C>
Revenue, before royalties (1)	$ 11,643	$ 2,826	$ 3,108	$ 3,041	$ 2,668
Net earnings	$ 2,524	$ 313	$ 1,116	$ 1,038	$ 57
Net earnings per common share					
- basic	$ 4.70	$ 0.58	$ 2.08	$ 1.93	$ 0.11
- diluted	$ 4.70	$ 0.58	$ 2.08	$ 1.93	$ 0.11

<CAPTION>

2005	TOTAL	DEC 31	SEP 30	JUN 30	MAR 31(2)
<S>	<C>	<C>	<C>	<C>	<C>
Revenue, before royalties (1)	$ 11,130	$ 3,319	$ 3,163	$ 2,420	$ 2,228
Net earnings (loss)	$ 1,050	$ 1,104	$ 151	$ 219	$ (424)
Net earnings (loss) per common share					
- basic	$ 1.96	$ 2.06	$ 0.28	$ 0.41	$ (0.79)
- diluted	$ 1.95	$ 2.06	$ 0.28	$ 0.41	$ (0.79)

</TABLE>

(1) Blending costs previously netted against gross revenues in prior periods have been reclassified to transportation expense to conform to the presentation adopted in the fourth quarter of 2006.
(2) Restated to reflect two-for-one share split in May 2005.

The Company's quarterly consolidated revenues increased 27% to $2,826 million in the fourth quarter of 2006 from $2,228 million in the first quarter of 2005. Quarterly revenues during 2006 primarily reflected increased world benchmark crude oil prices and increased crude oil and NGLs and natural gas sales volumes, partially offset by decreased natural gas prices. Quarterly revenues during 2005 primarily reflected increased world benchmark crude oil and natural gas prices and increased crude oil and NGLs and natural gas sales volumes.

o Crude oil prices reflected demand growth and continuing geopolitical uncertainties. Hurricane activity in the Gulf of Mexico in the third quarter of 2005 further contributed to increased world benchmark crude oil pricing. As a result, the Company's realized crude oil and NGLs price increased from C$39.81 per bbl for the first quarter of 2005 to C$47.27 per bbl for the fourth quarter of 2006. Realized natural gas prices decreased in 2006 from 2005 primarily due to decreased heating demand during the winter months and decreased cooling demand during the summer months. The Company's realized natural gas price decreased slightly from C$6.68 per mcf for the first quarter of 2005 to C$6.66 per mcf for the fourth quarter of 2006

o A stronger Canadian dollar reduced the Canadian dollar sales price the Company received for its crude oil sales, as crude oil prices are based on US dollar denominated benchmarks. The US / Canadian dollar average exchange rate increased from 0.8152 for the first quarter of 2005 to 0.8781 for the fourth quarter of 2006.

o Crude oil and NGLs and natural gas sales volumes increased in 2006 over 2005. The increase in crude oil and NGLs production from 2005 primarily reflected increased production from the Company's Primrose thermal projects, the positive results from the Pelican Lake waterflood project, additional production volumes from the ACC acquisition, development of West and East Espoir and the full year's impact of production from the Baobab Field located offshore Cote d'Ivoire. Production from the Baobab Field commenced August 2005. The increase in natural gas production from 2005 primarily reflected additional natural gas production from the ACC acquisition. The increase was partially offset by production decreases due to the effects of the Company's strategic reduction in natural gas drilling activity and increased North America crude oil drilling, made in response to sustained low natural gas prices and inflationary cost pressures. In total, daily production increased from 530,316 boe/d day in the first quarter of 2005 to 613,764 boe/d for the fourth quarter of 2006.

In addition to commodity prices and sales volumes, quarterly net earnings were impacted by:

o Increased production expense primarily due to the ACC acquisition and industry-wide inflationary cost pressures.

o Increased depletion, depreciation and amortization expense primarily due to increased finding and development costs associated with crude oil and natural gas exploration in North America, a higher depletion base due to the acquisition of ACC and increased estimated future costs to develop the Company's proved undeveloped reserves.

o Unrealized expense (recovery) due to the mark-to-market treatment of the Company's stock-based compensation liability.

o Unrealized gains and losses from the mark-to-market treatment of the

Company's commodity price hedges not designated as hedges for accounting purposes.

o Unrealized foreign exchange gains and losses due to the fluctuation of the Canadian dollar in relation to the US dollar with respect to the US dollar debt and working capital in North America denominated in US dollars, as well as the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling.

o Jurisdictional corporate tax rate changes substantively enacted in the period.

<TABLE>
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BUSINESS ENVIRONMENT

(Yearly average)	2006	2005	2004
<S>	<C>	<C>	<C>
WTI benchmark price (US$/bbl) (1)	$ 66.25	$ 56.61	$ 41.43
Dated Brent benchmark price (US$/bbl)	$ 65.18	$ 54.45	$ 38.28
Differential to LLB blend (US$/bbl)	$ 21.69	$ 20.83	$ 13.44
Differential to LLB blend as a % of WTI	33%	37%	32%
Condensate benchmark price (US$/bbl)	$ 66.24	$ 57.25	$ 41.62
NYMEX benchmark price (US$/mmbtu)	$ 7.26	$ 8.56	$ 6.09
AECO benchmark price (C$/GJ)	$ 6.62	$ 8.05	$ 6.43
US/Canadian dollar average exchange rate (US$)	$ 0.8818	$ 0.8253	$ 0.7683

</TABLE>
(1) Refers to West Texas Intermediate crude oil prices per barrel at Cushing, Oklahoma.

COMMODITY PRICES

World benchmark crude oil prices increased during the first part of 2006 due to ongoing demand growth and geopolitical uncertainties. However, pricing significantly declined later in the year, reflecting higher crude oil inventories. In December 2006, WTI averaged US$62.09 per bbl, a decline of 21% from the record high of US$78.40 per bbl reached in July 2006. WTI averaged US$66.25 per bbl in 2006, an increase of 17% compared to US$56.61 per bbl in 2005 (2004 - US$41.43 per bbl).

The Company's realized crude oil price increased from 2005 as a result of the increased WTI price and the narrower Heavy Differential. Heavy Differentials averaged 33% for 2006 compared to 37% for 2005 (2004 - 32%). The narrowing of the Heavy Differentials from 2005 was primarily due to reduced availability of imported grades from Venezuela and Mexico, reduced Canadian production of heavy crude oil and the removal of logistical constraints in accessing new markets in the US Gulf Coast due to the Pegasus and Spearhead pipelines commencing operations during 2006. The increase in realized crude oil prices from 2005 was partially offset by the negative impact of a strengthening Canadian dollar relative to the US dollar. A strengthening Canadian dollar reduces the Canadian dollar sales price the Company receives for its crude oil sales, as crude oil prices are based on US dollar denominated benchmarks.

The Company anticipates continued volatility in the crude oil markets as inventory levels remain high and given the unpredictable nature of geopolitical events.

Brent averaged US$65.18 per bbl in 2006, an increase of 20% compared to US$54.45 per bbl in 2005 (2004 - US$38.28 per bbl). Crude oil sales contracts for the Company's North Sea and Offshore West Africa segments are typically based on Brent pricing, which has benefited from strong European and Asian demand in 2006.

NYMEX natural gas prices averaged US$7.26 per mmbtu in 2006, a decrease of 15% from US$8.56 per mmbtu in 2005 (2004 - US$6.09 per mmbtu). AECO natural gas pricing in 2006 decreased 18% from 2005 to average C$6.62 per GJ. The decrease in natural gas pricing in 2006 from 2005 reflected the impact of exceptionally mild winter weather and reduced heating demand, relatively stable summer weather and reduced cooling demand, and the continuing impact of high natural gas inventory levels.

The Company anticipates a challenging natural gas pricing environment in the near term given the high storage levels. Longer term natural gas pricing will continue to be largely weather dependent.

OPERATING AND CAPITAL COSTS

Strong commodity prices in recent years have resulted in increased demand and costs for oilfield services worldwide. This has lead to inflationary production and capital cost pressures throughout the North American crude oil and natural gas industry, particularly related to natural gas drilling activity and oil sands developments. The strong commodity price environment has also impacted costs in international basins. Specifically, the high demand for offshore drilling rigs continues and securing rigs on commercially acceptable terms is an ongoing challenge.

The oil and gas industry is also experiencing cost pressures related to increasingly stringent environmental regulations, both in North America and internationally. In addition, environmental regulations in Canada intended to reduce greenhouse gas emissions are pending and the impact of the legislation is uncertain at this time.

These increased cost pressures and environmental regulations may adversely impact the Company's future net earnings, cash flow and increase the costs of capital projects.

<TABLE>
<CAPTION>
REVENUE, BEFORE ROYALTIES
ANALYSIS OF CHANGES IN REVENUE, BEFORE ROYALTIES

($ millions)	2004	Changes due to Volumes	Changes due to Prices	Changes due to Other	2005	Changes due to Volumes	Changes due to Prices	Changes due to Other	2006

<S>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>
North America									
Crude oil and NGLs (1)	$ 3,300	$ 170	$ 847	$ -	$ 4,317	$ 198	$ 747	$ -	$ 5,262
Natural gas	3,401	208	1,029	-	4,638	168	(1,002)	-	3,804
	6,701	378	1,876	-	8,955	366	(255)	-	9,066
North Sea									
Crude oil and NGLs	1,223	31	382	-	1,636	(168)	132	-	1,600
Natural gas	94	(59)	(12)	-	23	(4)	(3)	-	16
	1,317	(28)	370	-	1,659	(172)	129	-	1,616
Offshore West Africa									
Crude oil and NGLs	208	182	86	-	476	344	111	-	931
Natural gas	14	(6)	1	-	9	12	(2)	-	19
	222	176	87	-	485	356	109	-	950
Subtotal									
Crude oil and NGLs	4,731	383	1,315	-	6,429	374	990	-	7,793
Natural Gas	3,509	143	1,018	-	4,670	176	(1,007)	-	3,839
	8,240	526	2,333	-	11,099	550	(17)	-	11,632
Midstream	68	-	-	9	77	-	-	(5)	72
Intersegment eliminations and other (2)	(39)	-	-	(7)	(46)	-	-	(15)	(61)
Total	$ 8,269	$ 526	$ 2,333	$ 2	$ 11,130	$ 550	$ (17)	$ (20)	$ 11,643

</TABLE>

(1) Blending costs previously netted against gross revenues in prior years have been reclassified to transportation and blending expense to conform to the presentation adopted in 2006.

(2) Eliminates primarily internal transportation and electricity charges.

Revenue increased 5% to $11,643 million in 2006 from $11,130 million in 2005 (2004 - $8,269 million). The increase was primarily due to increased crude oil and NGLs and natural gas sales volumes in North America and Offshore West Africa and increased realized crude oil and NGLs prices, partially offset by decreased realized natural gas prices.

In 2006, 22% of the Company's crude oil and natural gas revenue was generated outside of North America (2005 - 19%; 2004 - 19%). North Sea accounted for 14% of crude oil and natural gas revenue in 2006 (2005 - 15%; 2004 - 16%), and Offshore West Africa accounted for 8% of crude oil and natural gas revenue in 2006 (2005 - 4%; 2004 - 3%).

<TABLE>
<CAPTION>

ANALYSIS OF PRODUCT PRICES (1)

	2006	2005	2004
<S>	<C>	<C>	<C>
Crude oil and NGLs ($/bbl) (2)			
North America	$ 46.52	$ 39.62	$ 33.16
North Sea	$ 72.62	$ 66.57	$ 51.37
Offshore West Africa	$ 67.99	$ 59.91	$ 49.05
Company average	$ 53.65	$ 46.86	$ 37.99
Natural gas ($/mcf) (2)			
North America	$ 6.77	$ 8.65	$ 6.61
North Sea	$ 2.66	$ 3.17	$ 3.73
Offshore West Africa	$ 5.37	$ 5.91	$ 5.25
Company average	$ 6.72	$ 8.57	$ 6.50
Company average ($/boe) (2)	$ 47.92	$ 48.77	$ 38.45
Percentage of revenue (excluding midstream revenue)			
Crude oil and NGLs	64%	54%	54%
Natural gas	36%	46%	46%

</TABLE>

(1) Net of transportation and blending costs and excluding risk management activities.

(2) Amounts expressed on a per unit basis are based on sales volumes.

Realized crude oil and NGLs prices increased 14% to average $53.65 per bbl in 2006 from $46.86 per bbl in 2005 (2004 - $37.99 per bbl). The increase from 2005 was due to increased benchmark crude oil prices and a narrower Heavy Differential, partially offset by the impact of a stronger Canadian dollar.

The Company's realized natural gas price decreased 22% to average $6.72 per mcf in 2006 from $8.57 per mcf in 2005 (2004 - $6.50 per mcf), reflecting record levels of natural gas inventory in North America, primarily due to the impact of exceptionally mild winter weather in 2006 that reduced heating demand and relatively stable summer weather that reduced cooling demand.

NORTH AMERICA

North America realized crude oil prices increased 17% to average $46.52 per bbl in 2006 from $39.62 per bbl in 2005 (2004 - $33.16 per bbl). The increase from 2005 was due to increased benchmark crude oil prices and a narrower Heavy Differential, partially offset by the impact of a stronger Canadian dollar.

In North America, the Company continues to focus on its crude oil marketing strategy, including the development of a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil conversion capacity. During 2006, the Company contributed approximately 136,000 bbl/d of heavy crude oil blends to the Western Canadian Select ("WCS") stream. The Company also continues to work with refiners to advance expansion of heavy crude oil conversion capacity, and is working with pipeline companies to develop new capacity to the Canadian West Coast and the US Gulf Coast where crude oil cargos can be sold on a world-wide basis. With a view to expanding markets for its heavy crude oil, the Company has committed to 25,000 bbl/d of capacity on the Pegasus Pipeline, which carries crude oil to the Gulf of Mexico. The Pegasus Pipeline is made up of a series of segments extending from Patoka, Illinois to Nederland, Texas, near the Gulf Coast. The Company's first sales from the Pegasus Pipeline occurred in April 2006. The Company also entered into an agreement to supply 25,000 bbl/d of heavy crude oil production to a new merchant upgrader to be constructed in Alberta. The agreement is for a period of five years, with first deliveries anticipated to occur in 2010 upon completion of construction of the facilities.

North America realized natural gas prices decreased 22% to average $6.77 per mcf in 2006 from $8.65 per mcf in 2005 (2004 - $6.61 per mcf), primarily due to reduced seasonal heating demand and reduced summer cooling demand in 2006.

A comparison of the price received for the Company's North America production by product type is as follows:

	2006	2005	2004
Wellhead price (1) (2)			
Light crude oil and NGLs (C$/bbl)	$ 63.09	$ 58.41	$ 45.90
Pelican Lake crude oil (C$/bbl)	$ 45.02	$ 38.39	$ 32.12
Primary heavy crude oil (C$/bbl)	$ 41.35	$ 33.53	$ 28.99
Thermal heavy crude oil (C$/bbl)	$ 40.98	$ 32.29	$ 29.00
Natural gas (C$/mcf)	$ 6.77	$ 8.65	$ 6.61

(1) Net of transportation and blending costs and excluding risk management activities.
(2) Amounts expressed on a per unit basis are based on sales volumes.

NORTH SEA

North Sea realized crude oil prices increased 9% to average $72.62 per bbl in 2006 from $66.57 per bbl 2005 (2004 - $51.37 per bbl). The increase in the realized crude oil price from 2005 was due primarily to the impact of strong European and Asian demand on Brent pricing, partially offset by the strengthening Canadian dollar in 2006 compared to 2005.

OFFSHORE WEST AFRICA

Offshore West Africa realized crude oil prices increased 13% to average $67.99 per bbl in 2006 from $59.91 per bbl in 2005 (2004 - $49.05 per bbl). The increase in the realized crude oil price from 2005 was due primarily to the impact of strong European and Asian demand on Brent pricing, partially offset by the strengthening Canadian dollar in 2006 compared to 2005.

CRUDE OIL INVENTORY VOLUMES

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. The related cumulative crude oil inventory volumes by segment, which have not been recognized in revenue, were as follows:

(bbl)	2006	2005
North America, related to pipeline fill	1,097,526	484,157
North Sea, related to timing of liftings	910,796	747,141
Offshore West Africa, related to timing of liftings	113,774	412,841
	2,122,096	1,644,139

In 2006, approximately 478,000 barrels of crude oil produced in the Company's North America and international operations were added to inventory and excluded from results of operations, decreasing cash flow from operations for the year by approximately $7 million.

<TABLE>
<CAPTION>
ANALYSIS OF DAILY PRODUCTION, BEFORE ROYALTIES

	2006	2005	2004
<S>	<C>	<C>	<C>
Crude oil and NGLs (bbl/d)			
North America	235,253	221,669	206,225
North Sea	60,056	68,593	64,706
Offshore West Africa	36,689	22,906	11,558
	331,998	313,168	282,489
Natural gas (mmcf/d)			
North America	1,468	1,416	1,330
North Sea	15	19	50
Offshore West Africa	9	4	8
	1,492	1,439	1,388
Total barrels of oil equivalent (boe/d)	580,724	552,960	513,835
Product mix			
Light crude oil and NGLs	26%	26%	24%
Pelican Lake crude oil	5%	4%	4%
Primary heavy crude oil	16%	17%	19%
Thermal heavy crude oil	11%	10%	8%
Natural gas	42%	43%	45%

DAILY PRODUCTION, NET OF ROYALTIES	2006	2005	2004
Crude oil and NGLs (bbl/d)			
North America	205,382	191,751	180,011
North Sea	59,940	68,487	64,598
Offshore West Africa	35,212	22,293	11,221
	300,534	282,531	255,830
Natural gas (mmcf/d)			
North America	1,185	1,125	1,048
North Sea	15	18	50
Offshore West Africa	9	4	7
	1,209	1,147	1,105
Total barrels of oil equivalent (boe/d)	502,024	473,742	440,022

</TABLE>

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/medium crude oil and NGLs, Pelican Lake crude oil, primary heavy crude oil and thermal heavy crude oil.

Total production of crude oil and NGLs before royalties increased 6% to 331,998 bbl/d from 313,168 bbl/d in 2005 (2004 - 282,489 bbl/d). The increase in crude oil and NGLs production from 2005 reflected increased production from the Company's Primrose thermal projects, the positive results from the Pelican Lake waterflood project, additional production volumes from the ACC acquisition, development of West and East Espoir and the full year's impact of production from the Baobab Field located offshore Cote d'Ivoire. Production from the Baobab Field commenced August 2005. Crude oil and NGLs production for 2006 was in line with the Company's revised guidance of 325,000 to 336,000 bbl/d.

Natural gas production continues to represent the Company's largest product offering. Total natural gas production before royalties increased 4% to 1,492 mmcf/d from 1,439 mmcf/d in 2005 (2004 - 1,388 mmcf/d). The increase in natural gas production from 2005 primarily reflected additional natural gas production from the ACC acquisition. The increase was partially offset by production decreases due to the impact of the Company's decision to reduce natural gas drilling activity in 2006, made in response to inflationary costs in Western Canada. Natural gas production for 2006 was at the bottom end of the Company's revised guidance of 1,492 to 1,501 mmcf/d.

In 2007, annual production is forecasted to average between 315,000 and 360,000 bbl/d of crude oil and NGLs and between 1,594 and 1,664 mmcf/d of natural gas.

NORTH AMERICA

North America crude oil and NGLs production in 2006 increased 6% to average 235,253 bbl/d from 221,669 bbl/d in 2005 (2004 - 206,225 bbl/d). The increase in production from 2005 was primarily due to increased production from the Company's Primrose thermal projects, the positive results from the Pelican Lake waterflood project and the ACC acquisition.

North America natural gas production in 2006 increased 4% to average 1,468 mmcf/d from 1,416 mmcf/d in 2005 (2004 - 1,330 mmcf/d). The increase in natural gas production from 2005 reflected the ACC acquisition, partially offset by production declines due to the Company's decision to reduce natural gas drilling activity. The ACC acquisition was completed in November with results

included from that date. To date, the ACC properties are performing as expected.

NORTH SEA

North Sea crude oil production in 2006 was 60,056 bbl/d, a decrease of 12% from 68,593 bbl/d in 2005 (2004 - 64,706 bbl/d). Production levels in 2006 were in line with expectations, reflecting the production effects of planned maintenance shutdowns in the second half of 2006.

OFFSHORE WEST AFRICA

Offshore West Africa crude oil production in 2006 increased 60% to 36,689 bbl/d from 22,906 bbl/d in 2005 (2004 - 11,558 bbl/d). The increase from 2005 was primarily due to the impact of a full year's production from the Baobab Field, first crude oil from West Espoir and a successful infill drilling campaign at East Espoir. The increase was partially offset by continuing challenges with sand and solids production at the Baobab Field that resulted in the shut in of 5 production wells. The Company does not plan to recomplete these wells until such time as a deepwater rig can be secured on commercially acceptable terms.

<TABLE>
<CAPTION>
ROYALTIES

2006	2005	2004
<S>	<C>	<C>	<C>
Crude oil and NGLs ($/bbl) (1)			
North America	$ 5.86	$ 5.37	$ 4.21
North Sea	$ 0.13	$ 0.10	$ 0.08
Offshore West Africa	$ 2.81	$ 1.62	$ 1.43
Company average	$ 4.48	$ 3.97	$ 3.16
Natural gas ($/mcf) (1)			
North America	$ 1.31	$ 1.78	$ 1.40
North Sea	$ -	$ -	$ -
Offshore West Africa	$ 0.22	$ 0.16	$ 0.15
Company average	$ 1.29	$ 1.75	$ 1.35
Company average ($/boe) (1)	$ 5.89	$ 6.82	$ 5.37
Percentage of revenue (2)			
Crude oil and NGLs	8%	8%	8%
Natural gas	19%	20%	21%
Boe	12%	14%	14%

</TABLE>
(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.

NORTH AMERICA

Crown Royalties on a significant portion of North America crude oil and NGLs production falls under the oil sands royalty regime and is calculated on a project by project basis as a percentage of gross revenue less operating, capital and abandonment costs ("net profit"). Royalties are calculated as 1% of gross revenues until the Company's capital investments in the applicable project are fully recovered, at which time the royalty increases to 25% of net profit.

Crude oil and NGLs royalties increased in 2006 primarily due to increased crude oil prices and the full recovery of the Company's capital investments in the Primrose North and South Fields in the second half of the year. Upon full recovery, Crown royalty rates on the Primrose North and South Fields increased from 1% of gross revenue to 25% of net profit. North America crude oil and NGLs royalties per bbl are anticipated to be 14% to 16% of gross revenue in 2007, an increase from 13% in 2006 (2005 - 14%; 2004 - 13%).

Natural gas royalties per mcf decreased from 2005 primarily due to decreased benchmark natural gas prices. Benchmark natural gas prices decreased primarily in response to reduced demand and increased storage levels. North America natural gas royalties per mcf are anticipated to be 21% to 23% of gross revenue in 2007, an increase from 19% in 2006 (2005 - 21%; 2004 - 21%).

NORTH SEA

North Sea government royalties on crude oil were eliminated effective January 1, 2003. The remaining North Sea royalty represents a gross overriding royalty on the Ninian Field.

OFFSHORE WEST AFRICA

Offshore West Africa production is governed by the terms of the various Production Sharing Contracts ("PSCs"). Under the PSCs, revenues are divided into cost recovery revenue and profit revenue. Cost recovery revenue allows the Company to recover its capital and operating costs and the costs carried by the Company on behalf of the Government State Oil Company. These revenues are reported as sales revenue. Profit revenue is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Government. The Government's share of profit revenue attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the PSCs. The Company's capital investments in the Espoir Field are expected to be fully recovered early in 2007, increasing royalty rates and current income taxes in accordance with the PSCs. The Company's capital investments in the Baobab Field are now

not expected to be fully recovered until approximately 2012 due to the ongoing production curtailments resulting from limitations to sand screen effectiveness.

In connection with corporate income tax rate reductions enacted by the Government of Cote d'Ivoire during the year that were effective January 1, 2006, royalty rates as a percentage of gross revenue increased from approximately 3% in 2005 to approximately 4% in 2006. As a result, production volumes net of royalties decreased approximately 2% in 2006 from 2005, in accordance with the terms of the PSC's. Royalty rates in 2007 are anticipated to be 13% to 15% of gross revenue due to the Company's expected full recovery of its capital investments in the Espoir Field.

PRODUCTION EXPENSE

	2006	2005	2004
Crude oil and NGLs ($/bbl) (1)			
North America	$ 11.73	$ 10.49	$ 8.94
North Sea	$ 17.57	$ 14.94	$ 14.03
Offshore West Africa	$ 7.45	$ 6.50	$ 7.59
Company average	$ 12.29	$ 11.17	$ 10.05
Natural gas ($/mcf) (1)			
North America	$ 0.81	$ 0.71	$ 0.62
North Sea	$ 1.40	$ 2.44	$ 2.07
Offshore West Africa	$ 1.19	$ 1.05	$ 1.33
Company average	$ 0.82	$ 0.73	$ 0.67
Company average ($/boe) (1)	$ 9.14	$ 8.21	$ 7.35

(1) Amounts expressed on a per unit basis are based on sales volumes.

NORTH AMERICA

North America crude oil and NGLs production expense in 2006 increased 12% to $11.73 per bbl from $10.49 per bbl in 2005 (2004 -$8.94 per bbl). The increase in production expense from 2005 was primarily due to increased industry wide service costs and increased cyclic steaming costs related to the Company's thermal crude oil projects, due to the timing of secondary steaming cycles.

North America natural gas production expense in 2006 increased 14% to $0.81 per mcf from $0.71 per mcf in 2005 (2004 - $0.62 per mcf), due to increased cost pressures.

Production expense per boe in 2007 is anticipated to continue to reflect industry wide inflationary cost pressures.

NORTH SEA

North Sea crude oil production expense increased on a per barrel basis from 2005 due to planned maintenance shutdowns, varying sales volumes on a relatively fixed cost base and the timing of liftings from various fields.

OFFSHORE WEST AFRICA

Offshore West Africa crude oil production expense on a per barrel basis increased from 2005 primarily due to continuing operating challenges with sand and solids resulting in decreased production volumes at Baobab, on a relatively fixed operating cost base.

MIDSTREAM

($ millions)	2006	2005	2004
Revenue	$ 72	$ 77	$ 68
Production expense	23	24	20
Midstream cash flow	49	53	48
Depreciation	8	8	7
Segment earnings before taxes	$ 41	$ 45	$ 41

The Company's midstream assets consist of three crude oil pipeline systems and a 50% working interest in an 84-megawatt cogeneration plant at Primrose. Approximately 80% of the Company's heavy crude oil production is transported to international mainline liquid pipelines via the 100% owned and operated ECHO Pipeline, the 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold Lake Pipeline. The midstream pipeline assets allow the Company to control the transport of its own production volumes as well as earn third party revenue. This transportation control enhances the Company's ability to manage the full range of costs associated with the development and marketing of its heavier crude oil.

DEPLETION, DEPRECIATION AND AMORTIZATION (1)

($ millions, except per boe amounts)(2)	2006	2005	2004
North America	$ 1,897	$ 1,595	$ 1,444
North Sea	297	306	265
Offshore West Africa	189	104	53
Expense	$ 2,383	$ 2,005	$ 1,762
$/boe	$ 11.27	$ 10.02	$ 9.37

(1) DD&A excludes depreciation on midstream assets.
(2) Amounts expressed on a per unit basis are based on sales volumes.

Depletion, Depreciation and Amortization ("DD&A") expense in 2006 increased 19% to $2,383 million from $2,005 million in 2005 (2004 - $1,762 million). The increase in DD&A expense in total and on a boe basis in 2006 from 2005 was primarily as a result of increased production combined with overall increases in finding and development costs associated with crude oil and natural gas exploration in North America, a higher depletion base due to the acquisition of ACC, and increased estimated future costs to develop the Company's proved undeveloped reserves.

ASSET RETIREMENT OBLIGATION ACCRETION

($ millions, except per boe amounts)(1)	2006	2005	2004
North America	$ 35	$ 34	$ 28
North Sea	31	34	22
Offshore West Africa	2	1	1
Expense	$ 68	$ 69	$ 51
$/boe	$ 0.32	$ 0.34	$ 0.27

(1) Amounts expressed on a per unit basis are based on sales volumes.

Accretion expense is the increase in the carrying amount of the ARO due to the passage of time. ARO accretion expense was comparable to 2005.

ADMINISTRATION EXPENSE

($ millions, except per boe amounts)(1)	2006	2005	2004
Net expense	$ 180	$ 151	$ 125
$/boe	$ 0.85	$ 0.75	$ 0.66

(1) Amounts expressed on a per unit basis are based on sales volumes.

Net administration expense in 2006 increased in total and on a boe basis from 2005 primarily due to increased insurance premiums, increased staffing and administrative costs, costs associated with the integration of ACC, and overall inflationary cost pressures.

STOCK-BASED COMPENSATION

($ millions)	2006	2005	2004
Stock-based compensation expense	$ 139	$ 723	$ 249

The Company's Stock Option Plan (the "Option Plan") provides current employees (the "option holders") with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. The design of the Option Plan balances the need for a long-term compensation program to retain employees with the benefits of reducing the impact of dilution on current Shareholders and the reporting of the obligations associated with stock options. Transparency of the cost of the Option Plan is increased since changes in the intrinsic value of outstanding stock options are recognized each period. The cash payment feature provides option holders with substantially the same benefits and allows them to realize the value of their options through a simplified administration process.

The Company recorded a $139 million ($95 million after-tax) stock-based compensation expense during 2006 in connection with the 8% appreciation in the Company's share price (December 31, 2006 - C$62.15; December 31, 2005 - C$57.63; December 31, 2004 - C$25.63; December 31, 2003 - C$16.34). As required by GAAP, the Company's outstanding stock options are valued based on the difference between the exercise price of the stock options and the market price of the Company's common shares, pursuant to a graded vesting schedule. The liability is revalued quarterly to reflect changes in the market price of the Company's common shares and the options exercised or surrendered in the period, with the net change recognized in net earnings, or capitalized during the construction period in the case of the Horizon Project (2006 - $79 million; 2005 - $101 million; 2004 - $21 million). The stock-based compensation liability reflected the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on December 31, 2006. In periods when substantial stock price changes occur, the Company is subject to significant earnings volatility.

For the year ended December 31, 2006, the Company paid $264 million for stock options surrendered for cash settlement (December 31, 2005 - $227 million; 2004 - - $80 million).

<TABLE>
<CAPTION>
INTEREST EXPENSE

($ millions, except per boe amounts and interest rates)(1)	2006	2005	2004
<S>	<C>	<C>	<C>
Interest expense, gross	$ 336	$ 221	$ 189
Less: capitalized interest, Horizon Project	196	72	-
Interest expense, net	$ 140	$ 149	$ 189
$/boe	$ 0.66	$ 0.74	$ 1.01
Average effective interst rate	5.7%	5.6%	5.2%

</TABLE>
(1) Amounts expressed on a per unit basis are based on sales volumes.

Gross interest expense increased from 2005 primarily due to increased debt levels associated with the ACC acquisition and the financing of Horizon Project capital expenditures. The increase was partially offset by the impact of the strengthening Canadian dollar, which decreased interest expense on the Company's US dollar denominated debt securities.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, currency and interest rate exposures. These derivative financial instruments are not intended for trading or speculative purposes. Changes in fair value of derivative financial instruments formally designated as hedges are not recognized in net earnings until such time as the corresponding gains or losses on the related hedged items are also recognized. Changes in fair value of derivative financial instruments not formally designated as hedges are recognized in the balance sheet each period with the offset reflected in risk management activities in the consolidated statements of earnings.

The Company formally documents all derivative financial instruments designated as hedging transactions at the inception of the hedging relationship, in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated, both at inception of the hedge and on an ongoing basis.

The Company enters into commodity price contracts to manage anticipated sales of crude oil and natural gas production in order to protect cash flow for capital expenditure programs. Realized gains or losses on these contracts are included in risk management activities. Unrealized gains or losses on commodity price contracts not formally documented as hedges are also included in risk management activities.

The Company enters into interest rate swap agreements to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. Gains or losses on interest rate swap contracts formally designated as hedges are included in interest expense. Gains or losses on non-designated interest rate swap contracts are included in risk management activities.

The Company enters into cross-currency swap agreements to manage currency exposure on US dollar denominated long-term debt. The cross-currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. Gains or losses on the foreign exchange component of all cross-currency swap contracts are included in risk management activities. Gains or losses on the interest component of cross-currency swap contracts designated as hedges are included in interest expense.

Gains or losses on the termination of derivative financial instruments that have been accounted for as hedges are deferred under other assets or liabilities on the consolidated balance sheets and amortized into net earnings in the period in which the underlying hedged transactions are recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized immediately in net earnings. Gains or losses on the termination of derivative financial instruments that have not been accounted for as hedges are recognized in net earnings immediately.

($ millions)	2006	2005	2004
Realized loss (gain)			
Crude oil and NGLs financial instruments	$ 1,395	$ 753	$ 501
Natural gas financial instruments	(70)	283	5
Interest rate swaps	-	(9)	(32)
	$ 1,325	$ 1,027	$ 474
Unrealized (gain) loss			
Crude oil and NGLs financial instruments	$ (736)	$ 847	$ (47)
Natural gas financial instruments	(260)	77	-
Interest rate and currency swaps	(17)	1	7
	$ (1,013)	$ 925	$ (40)
TOTAL	$ 312	$ 1,952	$ 434

==========

The realized losses (gains) from crude oil and NGLs and natural gas financial instruments decreased (increased) the Company's average realized prices as follows:

	2006	2005	2004
Crude oil and NGLs ($/bbl) (1)	$ 11.57	$ 6.68	$ 4.85
Natural gas ($/mcf) (1)	$ (0.13)	$ 0.54	$ 0.01

(1) Amounts expressed on a per unit basis are based on sales volumes.

The realized gain on non-designated interest rate swaps would have decreased the Company's reported interest expense as follows:

($ millions, except interest rates)	2006	2005	2004
Interest expense as reported	$ 140	$ 149	$ 189
Less: realized risk management gain	-	(9)	(32)
	$ 140	$ 140	$ 157
Average effective interest rate	5.7%	5.2%	4.4%

As effective as commodity hedges are against reference commodity prices, a substantial portion of the derivative financial instruments entered into by the Company do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The Company is required to mark-to-market these non-designated hedges based on prevailing forward commodity prices in effect at the end of each reporting period. Accordingly, the unrealized risk management asset reflected at December 31 2006, the implied price differentials for the non-designated hedges for future years. Due to changes in crude oil and natural gas forward pricing and the reversal of prior year unrealized losses, the Company recorded a net unrealized gain of $1,013 million ($674 million after-tax) on its risk management activities in 2006 (2005 - a $925 million unrealized loss, $607 million after-tax; 2004 - a $40 million unrealized gain, $27 million after-tax).

The cash settlement amount of the risk management financial derivative instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their mark-to-market value at December 31, 2006.

In addition to the net risk management asset recognized on the balance sheet at December 31, 2006, the net unrecognized asset related to the estimated fair values of derivative financial instruments designated as hedges was $222 million (December 31, 2005 - net unrecognized liability of $990 million).

Details relating to outstanding derivative financial instruments at December 31, 2006 are disclosed in note 12 to the Company's audited annual consolidated financial statements as at December 31, 2006.

Effective January 1, 2007, the Company will adopt new accounting standards relating to the accounting for and disclosure of financial instruments. Accordingly, the Company will record all of its derivative financial instruments on the balance sheet at fair value, including those designated as hedges. Designated hedges are currently not recognized on the balance sheet but are disclosed in the notes to the consolidated financial statements. The estimated effects on the Company's consolidated balance sheet are discussed in further detail on page 68 of this MD&A.

FOREIGN EXCHANGE

($ millions)	2006	2005	2004
Realized foreign exchange (gain) loss	$ (12)	$ (29)	$ 3
Unrealized foreign exchange loss (gain)	134	(103)	(94)
Total	$ 122	$ (132)	$ (91)

The Company's operating results are affected by the exchange rates between the Canadian dollar, US dollar, and UK pound sterling. A majority of the Company's revenue is based on reference to US dollar benchmark prices. An increase in the value of the Canadian dollar in relation to the US dollar results in decreased revenue from the sale of the Company's production. Conversely a decrease in the value of the Canadian dollar in relation to the US dollar will result in increased revenue from the sale of the Company's production. Production expenses are subject to fluctuations due to changes in the exchange rate of the UK pound sterling to the US dollar related to North Sea operations. The value of the Company's US dollar denominated debt is also impacted by the value of the Canadian dollar in relation to the US dollar.

The realized foreign exchange loss in 2006 was primarily the result of foreign exchange rate fluctuations on working capital items denominated in US dollars or UK pounds sterling. The unrealized foreign exchange gain in 2006 was primarily related to the fluctuation of the Canadian dollar in relation to the US dollar with respect to the US dollar debt and working capital in North America denominated in US dollars, as well as the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling. The Canadian dollar ended the year at US$0.8581 compared to US$0.8577 at December 31, 2005

(December 31, 2004 - US$0.8308).

In order to mitigate a portion of the volatility associated with fluctuations in exchange rates, the Company has 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 income tax rates)	2006	2005	2004
Taxes other than income tax			
Current	$ 219	$ 203	$ 210
Deferred	37	(9)	(45)
Total	$ 256	$ 194	$ 165
Current income tax			
North America	$ 143	$ 99	$ 101
North Sea	30	155	2
Offshore West Africa	49	32	13
Total	$ 222	$ 286	$ 116
Future income tax	$ 652	$ 353	$ 474
Effective income tax rate	25.7%(1)	37.8%(2)	29.6%(3)

(1) Includes the effect of the following:
o a charge of $110 million related to the increased supplementary charge on oil and gas profits in the UK North Sea, substantively enacted early in 2006.
o a recovery of $438 million due to Canadian Federal, Alberta and Saskatchewan corporate income tax rate reductions enacted in 2006.
o a recovery of $67 million due to Offshore West Africa corporate income tax rate reductions enacted late in 2006.
(2) Includes the effect of a $19 million recovery due to a British Columbia corporate tax rate reduction enacted in 2005.
(3) Includes the effect of a $66 million recovery due to an Alberta corporate tax rate reduction enacted in 2004.

Taxes other than income tax includes current and deferred petroleum revenue tax ("PRT") and Canadian provincial capital taxes and surcharges. PRT is charged on certain fields in the North Sea at the rate of 50% of net operating income, after allowing for certain deductions including abandonment expenditures.

Taxable income from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in a future period. North America current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary depending upon the nature and amount of capital expenditures incurred in Canada in any particular year.

Income tax rate changes during 2006 resulted in a reduction of future income tax liabilities of approximately $438 million in North America, an increase of future income tax liabilities of approximately $110 million in the UK North Sea and a reduction of future income tax liabilities of approximately $67 million in Cote d'Ivoire.

During 2005, North America income tax rate changes resulted in a reduction of future income tax liabilities of approximately $19 million.

During 2004, North America income tax rate changes resulted in a reduction of future income tax liabilities of approximately $66 million.

During 2003, the Canadian Federal Government enacted legislation to change the taxation of resource income. The legislation reduces the corporate income tax rate on resource income from 28% to 21% over five years beginning January 1, 2003. Over the same period, the deduction for resource allowance is being phased out and a deduction for actual crown royalties paid is being phased in. As a result in 2007, crown royalties will be fully deductible and the Company will no longer be eligible for resource allowance in 2007 and future years.

The following table shows the effect of non-recurring benefits on income taxes:

<TABLE>
<CAPTION>

($ millions, except income tax rates)	2006	2005	2004
<S>	<C>	<C>	<C>
Income tax as reported			
Current income tax	$ 222	$ 286	$ 116
Future income tax expense	652	353	474
874	639	590	
Provincial corporate tax rate reductions	161	19	66
Canadian Federal and foreign corporate tax rate reductions	234	-	-
Total	$ 1,269	$ 658	$ 656
Expected effective income tax rate before			

non-recurring benefits	37.3%	39.0%	32.9%

</TABLE>

The effective income tax rate for 2006 decreased slightly from 2005 due to the effects of the phased elimination of the resource allowance, the phased deductibility of crown royalties and foreign jurisdictional corporate tax rate changes substantively enacted during the year. In 2007, based on budgeted prices and the current availability of tax pools, the Company expects to be cash taxable in Canada in the amount of $45 million to $75 million.

<TABLE>
<CAPTION>
NET CAPITAL EXPENDITURES (1)

($ millions)	2006	2005	2004
<S>	<C>	<C>	<C>
Expenditures on property, plant and equipment			
Net property acquisitions (dispositions) (2)	$ 4,733	$ (320)	$ 1,835
Land acquisition and retention	210	254	120
Seismic evaluations	130	132	89
Well drilling, completion and equipping	2,340	2,000	1,394
Pipeline and production facilities	1,314	1,295	821
Total net reserve replacement expenditures	8,727	3,361	4,259
Horizon Project			
Phase 1 construction costs (3)	2,768	1,249	-
Phases 2 and 3 costs	79	-	-
Capitalized interest, stock-based compensation and other (3)	338	250	291
Total Horizon Project	3,185	1,499	291
Midstream	12	4	16
Abandonments (4)	75	46	32
Head office	26	22	35
Total net capital expenditures	$ 12,025	$ 4,932	$ 4,633
By segment			
North America	$ 7,936	$ 2,530	$ 3,355
North Sea	646	387	608
Offshore West Africa	134	439	295
Other	11	5	1
Horizon Project	3,185	1,499	291
Midstream	12	4	16
Abandonments (4)	75	46	32
Head office	26	22	35
TOTAL	$ 12,025	$ 4,932	$ 4,633

</TABLE>

(1) Net capital expenditures do not include non-cash property, plant and equipment additions or disposals.
(2) Includes Business Combinations.
(3) Certain prior period amounts have been reclassified with respect to stock-based compensation costs.
(4) Abandonments represent expenditures to settle AROs and have been reflected as capital expenditures in this table.

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core regions where it can dominate the land base and infrastructure. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures in 2006 were $12,025 million compared to $4,932 million in 2005 (2004 - $4,633 million). The increase primarily reflected the $4,641(1) million acquisition of ACC (including working capital and other adjustments) and continued progress on the Company's larger, future growth projects, most notably the Horizon Project. Excluding the ACC acquisition and the Horizon Project, net capital expenditures were $4,085 million in 2006 compared to $3,433 million in 2005, reflecting the impact of $320 million in net property dispositions in 2005, and overall industry-wide inflationary pressures in 2006. During 2006, the Company drilled a total of 1,738 net wells consisting of 641 natural gas wells, 603 crude oil wells, 375 stratigraphic test and service wells, and 119 wells that were dry. The 375 stratigraphic test and service wells include 163 stratigraphic test wells related to the Horizon Project. This compared to 1,882 net wells drilled in 2005 (2004 - 1,449 net wells). The Company achieved an overall success rate of 91% in 2006, excluding the stratigraphic test and service wells (2005 -93% and 2004 -91%).

(1) The preliminary allocation of the ACC purchase price to assets acquired and liabilities assumed based on their fair values was as follows:

Property, plant and equipment	$ 6,249
Less - future income taxes	(1,438)
- asset retirement costs	(56)
Consideration for crude oil and natural gas properties	4,755
Non-cash working capital deficit assumed and other	(105)
Long-term debt assumed	(9)
Net purchase price - cash consideration	$ 4,641

NORTH AMERICA

North America, including the Horizon Project and the ACC acquisition, accounted for approximately 94% of the total capital expenditures for the year ended December 31, 2006 compared to approximately 83% in 2005 (2004 - 80%).

During 2006, the Company targeted 732 net natural gas wells, including 181 wells in Northeast British Columbia, 262 wells in the Northern Plains region, 177 wells in Northwest Alberta, and 112 wells in the Southern Plains region. The Company also targeted 619 net crude oil wells during the year. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 292 heavy crude oil wells, 144 Pelican Lake crude oil wells, and 8 light crude oil wells were drilled. Another 114 wells targeting light crude oil were drilled outside the Northern Plains as well as 61 thermal crude oil wells in the Company's In-Situ Oil Sands area.

Due to significant changes in relative commodity prices between crude oil and natural gas, the Company has taken the opportunity to access its large crude oil drilling inventory to maximize value in both the short and long term. To optimize netbacks in the short term, the Company will continue to focus on drilling crude oil wells in 2007 and, accordingly, will reduce natural gas drilling activity to manage overall capital spending. Deferred natural gas wells will be retained in the Company's prospect inventory, and will be drilled as natural gas commodity prices improve. Drilling on ACC acquired lands will be optimized as part of the overall capital program.

As part of the development of the Company's In-Situ Oil Sands Assets, the Company is continuing to develop its Primrose thermal projects. At the end of 2006, the Company had drilled 186 stratigraphic test and observation wells and 61 thermal oil wells. With first steaming for the Primrose North expansion commencing November 2005, overall Primrose thermal production in 2006 increased to approximately 64,000 bbl/d from 53,000 bbl/d in 2005. Initial steaming of the projects was completed late in 2006.

In November of 2005, the Company announced a phased expansion of its In-Situ Oil Sands assets. The next phase of this development is the Primrose East expansion, a new facility located 15 kilometers from the existing Primrose South steam plant and 25 kilometers from the Wolf Lake central processing facility. This phase of the expansion is anticipated to add an additional 40,000 bbl/d and received Board of Director's sanction in 2006. Detailed engineering and procurement is currently underway. The Company anticipates receiving regulatory approval for Primrose East in the first half of 2007, with drilling and construction planned to begin in the second half of 2007, and production expected to commence in 2009.

The next phase of the Company's In-Situ Oil Sands assets expansion is the Kirby project located 120 km north of the existing Primrose facilities. The Kirby project is anticipated to add an additional 30,000 bbl/d of production growth. The Company is targeting to file its formal regulatory application documents for this project in the second half of 2007. First steaming is anticipated to begin in 2011.

Development of new acreage and secondary recovery conversion projects at Pelican Lake continued as expected through 2006. Drilling consisted of 144 horizontal wells, with plans to drill 132 additional horizontal wells in 2007. The response from the polymer flood pilot continues to be positive. Based on the results of the pilot, the Company commenced the installation of 12 additional polymer skids in 2006 as part of the approval of the commercial polymer flood project. Pelican Lake production averaged approximately 30,000 bbl/d in 2006.

Originally announced in the fall of 2005, the scoping study for the proposed Canadian Natural Upgrader, outside of the Horizon Project, continued during 2006 and into early 2007. The terms of reference for this study involved the evaluation of product alternatives, location, technology, gasification and integration with existing assets using the same disciplined approach utilized in the Horizon Project. The next steps in this process would include a Design Basis Memorandum ("DBM") and Engineering Design Specification ("EDS") which would be required to be completed prior to construction and sanctioning of the project by the Board of Directors.

Based upon the results of the scoping study, which identified growing concerns relating to increased environmental costs for upgraders located in Canada, inflationary capital cost pressures and a narrowing Heavy Differential in North America, the Company has, at this point in time, deferred the DBM and EDS pending clarification on the cost of future environmental legislation and a more stable cost environment.

In 2007, the Company's overall drilling activity in North America is expected to comprise approximately 423 natural gas wells and 813 crude oil wells excluding stratigraphic and service wells.

HORIZON PROJECT

The Horizon Project is designed as a phased development and includes two components: the mining of bitumen and an onsite upgrader. Phase 1 production is expected to commence in the second half of 2008 at 110,000 bbl/d of 34(degree) API SCO. The phased approach provides the Company with improved cost and project controls including labour and materials management, and directionally mitigates the effects of growth on local infrastructure. Extensive front end design and the high degree of project definition have enabled the Company to obtain approximately 68% of Phase 1 costs on a fixed price basis. The high degree of up front project engineering and pre-planning is expected to reduce

the risks associated with scope changes.

The Horizon Project continued on schedule and on budget with construction 57% complete at year end. The project status as at December 31, 2006 was as follows:

- Detailed engineering was 94% complete;

- Over $5.1 billion in purchase orders and contracts have been awarded to date;

o Several key mechanical contracts, including general mechanical contracts for the hydrotreater and cogeneration areas, were awarded;

o Set 333 pipe rack modules, essentially forming the core infrastructure of the plant;

o Mine overburden removal was approximately 35% complete; and

o Site preparation and underground infrastructure was completed.

In 2005, the Board of Directors of the Company approved the construction costs for Phase 1 of the Horizon Project, with an approved budget of $6.8 billion. Cumulative construction spending to December 31, 2006 was approximately $4.0 billion. Final construction costs for Phase 1 may differ from the approved budget due to changes in the final scope and timing of completion of the project, and/or inflationary cost pressures.

NORTH SEA

In 2006, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During 2006, 9.2 net wells were drilled with an additional 4 net wells drilling at year end.

The development of the Lyell Field progressed during the year with the completion of construction, installation and tie-in of subsea infrastructure. Tranche 1 of the Lyell Field development comprises the drilling of 4 net wells and the workover of 2 existing wells. Production from the Lyell Field is expected to be at full capacity in the second half of 2007.

During 2006, construction of the Columba E Raw Water Injection project continued. The project consists of 2 injection wells.

OFFSHORE WEST AFRICA

During 2006, 5.8 net wells were drilled with 1 well drilling at year-end.

First crude oil from West Espoir commenced from 3 wells brought on-line during 2006. Late in the year 2 water injector wells were added. The West Espoir area development drilling will continue until 2008 with producer and injector wells being brought on-line as they are completed.

The Company purchased a 90% interest in the Olowi PSC offshore Gabon in October 2005, received Government approval of its development plan for this acquisition early in 2006 and received Board sanction for development in November 2006. Development plans include a FPSO handling input from 4 shallow-water producing platforms. Late in 2006 the Company signed a lease agreement for a FPSO with a primary term of ten years, commencing 2008.

<TABLE>
<CAPTION>
LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	2006	2005	2004
<S>	<C>	<C>	<C>
Working capital deficit (1)	$ 832	$ 1,774	$ 652
Long-term debt	$ 11,043	$ 3,321	$ 3,538
Shareholders' equity			
Share capital	$ 2,562	$ 2,442	$ 2,408
Retained earnings	8,141	5,804	4,922
Foreign currency translation adjustment	(13)	(9)	(6)
Total	$ 10,690	$ 8,237	$ 7,324
Debt to book capitalization (2)	50.8%	28.7%	33.8%
Debt to market capitalization	24.8%	9.7%	21.4%
After tax return on average common shareholders' equity (3)	26.9%	14.3%	21.4%
After tax return on average capital employed (4)	17.2%	10.4%	15.3%

</TABLE>
(1) Calculated as current assets less current liabilities.
(2) Calculated as current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.
(3) Calculated as net earnings for the year as a percentage of average common shareholders' equity for the year.
(4) Calculated as net earnings plus after-tax interest expense for the year; as a percentage of average capital employed. Average capital employed is the average shareholders' equity and current and long-term debt for the year.

The Company's capital resources at December 31, 2006 consisted primarily of cash flow from operations, available credit facilities and access to debt capital markets. Cash flow from operations is dependent on factors discussed in the Risks and Uncertainties section of this MD&A. The Company's ability to renew existing credit facilities and raise new debt is also dependent upon these factors, as well as maintaining an investment grade debt rating and the condition of capital and credit markets. Management believes internally generated cash flows supported by the implementation of the Company's hedge policy, the flexibility of its capital expenditure programs supported by its five-and ten-year financial plans, the Company's existing credit facilities and the Company's ability to raise new debt on commercially acceptable terms, will be sufficient to sustain its operations and support its growth strategy. The Company's current debt ratings are BBB (high) with a negative trend by DBRS,

Baa2 with a stable outlook by Moody's Investor Services, Inc. and BBB with a stable outlook by Standard and Poors Corporation.

At December 31, 2006, the Company had undrawn bank lines of credit of $1,115 million. Details related to the Company's credit facilities outstanding at December 31, 2006 are disclosed in note 5 to the Company's audited annual consolidated financial statements.

At December 31, 2006, the Company's working capital deficit was $832 million and included the current portion of the stock-based compensation liability of $611 million and the current portion of the net mark-to-market asset for non-designated risk management financial derivative instruments of $88 million. The settlement of the stock-based compensation liability is dependant upon both the surrender of vested stock options for cash settlement by employees and the value of the Company's share price at the time of surrender. The cash settlement amount of the risk management financial derivative instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their mark-to-market value at December 31, 2006.

The Company believes it has the necessary financial capacity to complete the Horizon Project, while at the same time not compromising conventional crude oil and natural gas growth opportunities. The financing of Phase 1 of the Horizon Project development is guided by the competing principles of retaining as much direct ownership interest as possible while maintaining a strong balance sheet. Existing proved development projects, which have largely been funded prior to December 31, 2006, such as Baobab, Primrose and West Espoir, and the acquisition of ACC, are anticipated to provide identified growth in production volumes in 2007 through 2009, and generate incremental free cash flows during this period.

Primarily due to the additional debt issued to complete the ACC acquisition, long-term debt increased to $11,043 million at December 31, 2006, resulting in a debt to book capitalization level of 50.8% as at December 31, 2006 (December 31, 2005 - 28.7%). While this ratio is above the 35% to 45% range targeted by management, the Company remains committed to maintaining a strong balance sheet and flexible capital structure, and expects its debt to book capitalization ratio to be near the midpoint of the range in 2008. While the Company believes that its balance sheet has the strength and flexibility to accommodate the ACC acquisition, to ensure balance sheet strength going forward, the Company has hedged a significant portion of its natural gas and crude oil production for 2007 and 2008 at prices that protect investment returns. In the future, the Company may also consider the divestiture of non-strategic and non-core properties to gain additional balance sheet flexibility.

The Company's commodity hedging program reduces the risk of volatility in commodity price markets and supports the Company's cash flow for its capital expenditure program throughout the Horizon Project construction period. This program allows for the hedging of up to 75% of the near 12 months budgeted production, up to 50% of the following 13 to 24 months expected production and up to 25% of production expected in months 25 to 48. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. In accordance with the policy, approximately 65% of expected crude oil volumes and approximately 75% of expected natural gas volumes have been hedged for 2007. In addition, 77,000 bbl/d of crude oil volumes are protected by put options for 2007 at a strike price of US$60.00 per barrel. The Company is extending its hedge program into 2008 whereby 150,000 bbl/d of crude oil volumes have been hedged (100,000 bbl/d of price collars with a US$60.00 floor and 50,000 bbl/d of put options with a US$55.00 strike price). In addition, 900,000 GJ/d of natural gas volumes have been hedged through the use of price collars for the first quarter of 2008 (400,000 GJ/d with a floor of $7.00 and 500,000 GJ/d with a floor of $7.50).

In addition to the strategic location of the assets that ACC brings to the Company, this acquisition allows the Company to further high grade its project inventory and focus capital expenditures in the current highly inflationary service market. As a result of the acquisition, the Company has reduced its 2007 conventional crude oil and natural gas capital budget by $900 million compared to 2006 capital spending, while maintaining the capital expenditures to complete Phase I of the Horizon Project.

LONG-TERM DEBT

The Company's long-term debt of $11,043 million at December 31, 2006 was comprised of drawings under its bank credit facilities and debt issuances under medium and long-term unsecured notes.

BANK CREDIT FACILITIES

As at December 31, 2006 the Company had in place unsecured bank credit facilities of $7,809 million, comprised of:

- a $100 million demand credit facility;
- a $500 million demand credit facility;
- a 3-year non-revolving syndicated credit facility of $3,850 million;
- a 5-year revolving syndicated credit facility of $1,825 million;
- a 5-year revolving syndicated credit facility of $1,500 million; and
- a (pound)15 million demand credit facility related to the Company's North Sea operations.

The revolving syndicated credit facilities are fully revolving for a period of five years maturing June 2011. Both facilities are extendible annually for one year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date.

In conjunction with the closing of the acquisition of ACC, the Company executed a $3,850 million, three-year non-revolving syndicated credit facility maturing in October 2009. This facility is subject to certain prepayment requirements up to a maximum of $1,500 million.

During 2006, the Company obtained a $500 million credit facility repayable on demand.

The weighted average interest rate of the bank credit facilities outstanding at December 31, 2006, was 4.8% (2005 - 4.0%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $338 million, including $300 million related to the Horizon Project, were outstanding at December 31, 2006.

MEDIUM-TERM NOTES

In January 2006, the Company issued $400 million of debt securities maturing January 2013, bearing interest at 4.50%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these securities, the Company has $1.6 billion remaining on its $2 billion shelf prospectus filed in August 2005 that allows for the issue of medium-term notes in Canada until September 2007. If issued, these securities will bear interest as determined at the date of issuance.

In May 2005, the Company issued $400 million of debt securities maturing June 2015, bearing interest at 4.95%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

Subsequent to December 31, 2006, the 7.40% unsecured debentures due March 1, 2007 were repaid.

SENIOR UNSECURED NOTES

The adjustable rate senior unsecured notes bear interest at 6.54% and have annual principal repayments of US$31 million commencing in May 2007, through May 2009.

In December 2005, the Company repaid the US$125 million 7.69% senior unsecured notes due December 19, 2005.

PREFERRED SECURITIES

In September 2005, the Company redeemed the US$80 million 8.30% preferred securities due May 25, 2011 for cash consideration of US$91 million, including an early repayment premium of US$11 million as required under the Note Purchase Program.

US DOLLAR DEBT SECURITIES

In August 2006, the Company issued US$250 million of unsecured notes maturing August 2016 and US$450 million of unsecured notes maturing February 2037, bearing interest at 6.00% and 6.50%, respectively. Concurrently, the Company entered into cross-currency interest-rate swaps to fix the Canadian dollar interest and principal repayment amounts on the US$250 million notes at 5.40% and C$279 million. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

In November 2006, the US shelf prospectus, filed in June 2005, was increased from US$2,000 million to US$3,000 million, leaving US$2,300 million available for issue in the United States until July 2007.

Subsequently, on March 12, 2007, the Company priced, for settlement on March 19, 2007, US$2,200 million of unsecured notes under the US shelf prospectus, comprised of US$1,100 million of unsecured notes maturing May 2017 and US$1,100 million of unsecured notes maturing March 2038, bearing interest at 5.70% and 6.25%, respectively. Concurrently, the Company entered into cross-currency interest-rate swaps to fix the Canadian dollar interest and principal repayment amounts on US$1,100 million of unsecured notes due May 2017 at 5.10% and C$1,287 million. The Company also entered into a cross-currency interest-rate swap to fix the Canadian dollar interest and principal repayment amounts on US$550 million of unsecured notes due March 2038 at 5.76% and C$644 million. Net proceeds on the debt issue will be used to repay outstanding amounts under the Company's bank credit facilities.

SHARE CAPITAL

As at December 31, 2006, there were 537,903,000 common shares outstanding and 34,425,000 stock options outstanding. As at March 13, 2007, the Company had 538,970,000 common shares outstanding and 31,098,000 stock options outstanding.

During 2006, the Company purchased 485,000 common shares for cancellation (2005 - - 850,000 common shares; 2004 - 873,400 common shares) at an average price of $57.33 per common share (2005 - $53.29 per common share; 2004 -$38.01 per common share), for a total cost of $28 million (2005 - $45 million; 2004 -$33 million) pursuant to the Normal Course Issuer Bids previously filed.

In January 2007, the Company renewed its Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the 12-month period beginning January 24, 2007 and ending January 23, 2008, up to 26,941,730 common shares or 5% of the outstanding common shares of the Company then outstanding on the date of the announcement. As at March 15, 2007, the Company had not purchased any additional shares under

the Normal Course Issuer Bid.

In March 2007, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.34 per common share for 2007. The increase represented a 13% increase from the prior year, recognizes the stability of the Company's cash flow, and provides a return to Shareholders. This is the seventh consecutive year in which the Company has paid dividends

and the sixth consecutive year of an increase in the distribution paid to its Shareholders. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change. In February 2006, an increase in the annual dividend paid by the Company was approved to $0.30 per common share for 2006. The increase represented a 27% increase from the prior year.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. These commitments primarily relate to debt repayments, operating leases relating to office space and offshore FPSOs and drilling rigs, and firm commitments for gathering, processing and transmission services, as well as expenditures relating to AROs. As at December 31, 2006, no entities have been consolidated under the Canadian Institute of Chartered Accountants Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at December 31, 2006:

<TABLE>
<CAPTION>

($ millions)	2007	2008	2009	2010	2011	Thereafter
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Product transportation and pipeline (1)	$ 213	$ 193	$ 134	$ 123	$ 99	$ 1,042
Offshore equipment opeating leases (2)	$ 77	$ 52	$ 52	$ 52	$ 50	$ 131
Offshore drilling	$ 73	$ 83	$ 12	$ 12	$ 4	$ 4
Asset retirement obligations (3)	$ 3	$ 3	$ 3	$ 4	$ 4	$ 4,480
Long-term debt (4)	$ 161	$ 45	$ 3,876	$ -	$ 466	$ 3,713
Office Leases	$ 26	$ 32	$ 33	$ 34	$ 22	$ -
Electricity and other	$ 51	$ 10	$ 17	$ 18	$ 1	$ -

</TABLE>

(1) The Company entered into a 25 year pipeline transportation agreement commencing in 2008, related to future crude oil production. The agreement is renewable for successive 10-year periods at the Company's option. During the initial term, annual toll payments before operating costs will be approximately $35 million.
(2) Offshore equipment operating leases are primarily comprised of obligations related to FPSOs. During 2006, the Company entered into an agreement to lease an additional FPSO commencing in 2008, in connection with the planned offshore development in Gabon, Offshore West Africa. The new FPSO lease agreement contains cancellation provisions at the option of the Company, subject to escalating termination payments throughout 2007 to a maximum of US$395 million.
(3) Amounts represent management's estimate of the future undiscounted payments to settle AROs related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2007 - 2011 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.
(4) The long-term debt represents principal repayments only. No debt repayments are reflected for $2,782 million of revolving bank credit facilities due to the extendable nature of the facilities.

In 2005, the Board of Directors of the Company approved the construction costs for Phase 1 of the Horizon Project, with an approved budget of $6.8 billion. Cumulative construction spending to December 31, 2006 was approximately $4.0 billion. Final construction costs for Phase 1 may differ from the approved budget due to changes in the final scope and timing of completion of the project, and/or inflationary cost pressures.

LEGAL PROCEEDINGS

The Company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The Company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

RESERVES

For the year ended December 31, 2006, the Company retained qualified independent reserve evaluators, Sproule Associates Limited ("Sproule") and Ryder Scott Company ("Ryder Scott") to evaluate 100% of the Company's conventional proved, as well as proved and probable crude oil, natural gas liquids ("NGL") and natural gas reserves(1) and prepare Evaluation Reports on these reserves. Sproule evaluated the Company's North America conventional assets and Ryder Scott evaluated the international conventional assets. The Company has been granted an exemption from National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada. This exemption allows the Company to substitute SEC requirements for certain disclosures required under NI 51-101. There are two principal differences between the two standards. The first is the additional requirement under NI 51-101 to disclose both proved, and proved and probable reserves, as well as the related net present value of future net revenues using forecast prices and costs. The second is in the definition of proved reserves; however, as discussed in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), the standards that NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material.

The Company has disclosed proved conventional reserves and the Standardized Measure of discounted future net cash flows using year-end constant prices and

costs as mandated by the SEC in the supplementary oil and gas information section of this Annual Report. The Company has elected to provide the net present value(2) of these same conventional proved reserves as well as its conventional proved and probable reserves and the net present value of these reserves under the same parameters as additional voluntary information. The Company has also elected to provide both proved, and proved and probable conventional reserves and the net present value of these reserves using forecast prices and costs as voluntary additional information, which is disclosed in the Company's most recent Annual Information Form.

For the year ended December 31, 2006, the Company retained a qualified independent reserves evaluator, GLJ Petroleum Consultants ("GLJ"), to evaluate 100% of Phases 1 through 3 of the Company's Horizon Project and prepare an Evaluation Report on the Company's proved, as well as proved and probable oil sands mining reserves incorporating both the mining and upgrading projects. These reserves were evaluated adhering to the requirements of SEC Industry Guide 7 using year-end constant pricing and have been disclosed separately from the Company's conventional proved and probable crude oil, NGL and natural gas reserves.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of Sproule, Ryder Scott and GLJ to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and net present value of remaining conventional crude oil, NGL and natural gas reserves as well as the Company's quantity of oil sands mining reserves.

Additional reserves disclosure is contained in the supplementary oil and gas information of this Annual Report and in the Company's most recent Annual Information Form.

(1) Conventional crude oil, NGLs and natural gas includes all of the Company's light/medium, heavy, and thermal crude oil, natural gas, coal bed methane and natural gas liquids activities. It does not include the Company's oil sands mining assets.

(2) Net present values of conventional reserves are based upon discounted cash flows prior to the consideration of income taxes and existing asset abandonment liabilities. Only future development costs and associated material well abandonment liabilities have been applied.

RISKS AND UNCERTAINTIES

The Company is exposed to various operational risks inherent in exploring, developing, producing and marketing crude oil and natural gas and the mining and upgrading of bitumen. These inherent risks include, but are not limited to, the following items:

o Economic risk of finding and producing reserves at a reasonable cost, including the risk of reserve revisions due to economic and technical factors. Reserve revisions can have a positive or negative impact on asset valuations, AROs and depletion rates;

o Pricing risk of marketing reserves at an acceptable price given current market conditions;

o Regulatory risk related to approval for exploration and development activities, which can add to costs or cause delays in projects;

o Labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner;

o Operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas;

o Success of exploration and development activities;

o Timing and success of integrating the business and operations of acquired companies;

o Credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts;

o Interest rate risk associated with the Company's ability to secure financing at commercially acceptable terms;

o Foreign exchange risk due to fluctuating exchange rates, as the majority of sales are based in US dollars;

o Environmental impact risk associated with exploration and development activities;

o Risk of catastrophic loss due to fire, explosion or acts of nature;

o Geopolitical risks associated with changing governmental policies, social instability and other political, economic or diplomatic developments in the Company's international operations; and

o Other circumstances affecting revenue and expenses.

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 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 crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Sales of crude 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 only entering into sales contracts and financial derivatives with highly rated entities and

financial institutions. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions. Refer to the "Risk management activities" section of this MD&A. 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 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.

For additional detail regarding the Company's risks and uncertainties, refer to the Company's most recent Annual Information Form.

ENVIRONMENT

The crude oil and natural gas industry is experiencing incremental increases in costs related to environmental regulation, particularly in North America and the North Sea. Existing and expected legislation and regulations will require the Company to address and mitigate the effect of its activities on the environment. This will include dismantling production facilities and remediating damage caused by the disposal or release of specified substances. Increasingly stringent laws and regulations may have an adverse effect on the Company's future net earnings and cash flow from operations.

The Company's associated risk management strategies focus on working with legislators and regulators to ensure that any new or revised policies, legislation or regulations properly reflect a balanced approach to sustainable development. Specific measures in response to existing or new legislation include a focus on the Company's energy efficiency, air emissions management, released water quality, reduced fresh water use and the minimization of the impact on the landscape. The Company's strategy employs an Environmental Management Plan (the "Plan"), a detailed copy of which is presented to, and reviewed by, the Board of Directors annually. The Plan is updated quarterly at the Directors' meetings.

The Company's Plan and operating guidelines focus on minimizing the impact of operations while meeting regulatory requirements and internal corporate standards. The Company, as part of this Plan, has implemented a proactive program that includes:

o An annual internal environmental compliance audit and inspection program of the Company's operating facilities;

o A suspended well inspection program to support future development or eventual abandonment;

o Appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment;

o An effective surface reclamation program;

o A due diligence program related to groundwater monitoring;

o An active program related to preventing and reclaiming spill sites;

o A solution gas reduction and conservation program; and

o A program to replace the majority of fresh water for steaming with brackish water.

The Company has also established stringent operating standards in four areas:

1 Using water-based, environmentally friendly drilling muds whenever possible;

2 Implementing cost effective ways of reducing greenhouse gas emissions per unit of production;

3 Exercising care with respect to all waste produced through effective waste management plans; and

4 Minimizing produced water volumes onshore and offshore through cost-effective measures.

In 2006, the Company's capital expenditures included $75 million for abandonment expenditures, an increase from $46 million in 2005 (2004 - $32 million).

The Company's estimated undiscounted ARO at December 31, 2006 was as follows:

Estimated ARO, undiscounted ($ millions)	2006	2005
North America	$ 2,826	$ 2,050
North Sea	1,543	1,185
Offshore West Africa	128	90
	4,497	3,325
North Sea PRT recovery	(625)	(370)
	$ 3,872	$ 2,955

The estimate of the ARO is based on estimates of future costs to abandon and restore the wells, production facilities and offshore production platforms. Factors that affect costs include number of wells drilled, well depth and the specific environmental legislation. The estimated costs are based on engineering estimates using current costs in accordance with present legislation and industry operating practice. 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. The future abandonment costs incurred in the North Sea are expected to result in an estimated PRT recovery of $625 million (2005 - $370 million, 2004 - $600 million), as abandonment costs are an allowable deduction in determining PRT and may be carried back to reclaim PRT previously paid. The expected PRT recovery reduces the Company's net abandonment liability to $3,872

million (2005 - $2,955 million).

GREENHOUSE GAS AND OTHER AIR EMISSIONS

The Company is concurrently working with legislators and regulators on the design of new greenhouse gas emission laws and regulations and is pursuing an integrated emissions reduction strategy, to ensure the Company is able to comply with existing and future emission reductions requirements. The Company continues to develop strategies that will enable it to deal with the risks and opportunities associated with new climate change policies. In addition, the Company is working with relevant parties to ensure that new policies encourage innovation, energy efficiency, targeted research and development while not impacting competitiveness.

The Company continues to work with Canadian Federal and Provincial governments on the regulatory framework for greenhouse gases for larger emitters. The Company is actively promoting a harmonized regulatory framework between the two levels of government. Both levels of government have indicated that existing legislation will be amended in 2007 to create further requirements for reporting emissions, facility-based emission intensity targets and regulatory compliance. Compliance with emission intensity targets is expected for 2008 and possibly a part of 2007 for larger facilities in Alberta.

Issues to be resolved include, but are not limited to: the outcome of discussions between the Federal and Provincial Governments, the impact of implementing legislation, the allocations of reduction obligations among industry sectors and international developments.

Any required reductions in the greenhouse gases emitted from the Company's operations could increase capital expenditures and operating expenses, especially those related to the Horizon Project and the Company's other existing and planned large oil sands projects. This may have an adverse effect on the Company's net earnings and cash flow from operations.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires the Company to make judgements, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the Company's financial position and reported results of operations. Actual results could differ from those estimates, and those differences could be material. Critical accounting estimates are reviewed by the Company's Audit Committee annually. The Company believes the following are the most critical accounting estimates in preparing its consolidated financial statements.

PROPERTY, PLANT AND EQUIPMENT/DEPLETION, DEPRECIATION AND AMORTIZATION

The Company follows the full cost method of accounting for its conventional crude oil and natural gas properties and equipment. Accordingly, all costs relating to the exploration for and development of conventional crude oil and natural gas reserves, whether successful or not, are capitalized and accumulated in country-by-country cost centres. 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. Under Canadian GAAP, substantially all of the capitalized costs and future capital 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 using estimated future prices and costs, rather than constant dollar pricing as required by the SEC. The carrying amount of crude oil and natural gas properties in each cost centre may not exceed their recoverable amount ("the ceiling test"). The recoverable amount is calculated as the undiscounted cash flow using proved reserves and estimated future prices and costs. If the carrying amount of a cost centre exceeds its recoverable amount, an impairment loss equal to the amount by which the carrying amount of the properties exceeds their estimated fair value is charged against net earnings. Fair value is calculated as the cash flow from those properties using proved and probable reserves and estimated future prices and costs, discounted at a risk-free interest rate.

The alternate acceptable method of accounting for crude 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. The use of the full cost method usually results in higher capitalized costs and increased DD&A rates compared to the successful efforts method.

CRUDE OIL AND NATURAL GAS RESERVES

The Company retains qualified independent reserves evaluators to evaluate the Company's proved, and proved and probable crude oil and natural gas reserves. In 2006, 100% of the Company's reserves were evaluated by qualified independent reserves evaluators.

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 depletion, depreciation and amortization and for determining potential asset impairment. For example, a

revision to the proved reserve estimates would 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 crude oil and natural gas property, plant and equipment carrying amounts under the ceiling test.

ASSET RETIREMENT OBLIGATIONS

Under CICA Handbook Section 3110, Asset Retirement Obligations, the Company is required to recognize a liability for the future retirement obligations associated with its property, plant and equipment. An ARO is recognized to the extent of a legal obligation associated with the retirement of a tangible long-lived asset the Company is required to settle as a result of an existing or enacted law, statute, ordinance or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company's total ARO amount. These individual assumptions can be subject to change based on experience.

The estimated fair values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. Retirement costs equal to the estimated fair value of the ARO is capitalized as part of the cost of associated capital assets and are amortized to expense through depletion over the life of the asset. The fair value of the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company's average credit-adjusted risk-free interest rate, which is currently 6.7%. In subsequent periods, the ARO is adjusted for the passage of time and for any changes in the amount or timing of the underlying future cash flows. The estimates described impact earnings by way of depletion on the capital cost and accretion on the asset retirement liability. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates could result in gains or losses on the final settlement of the ARO.

An ARO is not recognized for assets with an indeterminate useful life (e.g. pipeline assets) because an amount cannot be reasonably determined. An ARO for these assets will be recorded in the first period in which the lives of these assets are determinable.

INCOME TAXES

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 as of the consolidated balance sheet date. Accounting for income taxes is an inherently complex process that requires management to interpret frequently changing regulations (e.g. changing income tax rates) and make certain judgements with respect to the application of tax law. These interpretations and judgements impact the current and future income tax provisions, future income tax assets and liabilities and net earnings.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various instruments to manage its commodity price, currency and interest rate exposures. These derivative and financial instruments are not intended for trading or speculative purposes.

On January 1, 2004, the fair values of all outstanding derivative financial instruments that were not designated as hedges for accounting purposes were recorded on the consolidated balance sheet, with an offsetting net deferred revenue amount. Subsequent net changes in the fair value of non-designated financial instruments have been recognized on the consolidated balance sheet and in net earnings. The estimated fair value for all derivative financial instruments is based on third party indications. The cash settlement amount of the derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the derivative financial instruments, as compared to their mark-to-market value at December 31, 2006.

Effective January 1, 2007, the Company will adopt new accounting standards relating to the accounting for and disclosure of financial instruments. The estimated effects on the Company's consolidated balance sheet are discussed in further detail on page 68 of this MD&A.

PURCHASE PRICE ALLOCATIONS

The costs of business combinations and asset acquisitions are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make assumptions and estimates regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future DD&A expense and impairment tests.

The Company has made various assumptions in determining the fair values of the acquired assets and liabilities. The most significant assumptions and judgments relate to the estimation of the fair value of the crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates (a) crude oil and natural gas reserves, and (b) future prices of crude oil and natural gas. Reserve estimates are based on the work performed by the Company's engineers and outside consultants. The judgments associated with these estimated reserves are described above in "Crude oil and natural gas

reserves". Estimates of future prices are based on prices derived from price forecasts among industry analysts and internal assessments. The Company applies estimated future prices to the estimated reserves quantities acquired, and estimates future operating and development costs, to arrive at estimated future net revenues for the properties acquired.

CONTROL ENVIRONMENT

The Company's management, including the President and Chief Operating Officer and the Chief Financial Officer and Senior Vice-President, Finance, evaluated the effectiveness of disclosure controls and procedures as at December 31, 2006, and concluded that disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its annual filings and other reports filed with securities regulatory authorities in Canada and the United States is recorded, processed, summarized and reported within the time periods specified and such information is accumulated and communicated to allow timely decisions regarding required disclosures.

The President and Chief Operating Officer and the Chief Financial Officer and Senior Vice-President, Finance also performed an assessment of internal control over financial reporting as at December 31, 2006, and concluded that internal control over financial reporting is effective. Further, there were no changes in the Company's internal control over financial reporting during 2006 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

While the Company believes that its disclosure controls and procedures and internal controls over financial reporting provide a reasonable level of assurance that they are effective, it recognizes that all internal control systems have inherent limitations. Because of its inherent limitations, the Company's internal control system may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

NEW ACCOUNTING STANDARDS

Effective January 1, 2007, the Company will adopt the following new accounting standards relating to the accounting for and disclosure of financial instruments:

o Section 1530 - "Comprehensive Income" introduces the concept of comprehensive income to Canadian GAAP. Comprehensive income is the change in equity (net assets) of the Company during a reporting period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners.

Foreign currency translation adjustment, which is currently a separate component of shareholders' equity, will be recorded as part of accumulated other comprehensive income.

o Section 3251 - "Equity" replaces Section 3250 - "Surplus" and establishes standards for the presentation of equity and changes in equity during a reporting period. Financial statements of prior periods will be restated only for the foreign currency translation adjustment.

o Section 3855 - "Financial Instruments - Recognition and Measurement" prescribes when a financial asset, financial liability, or nonfinancial derivative is to be recognized on the balance sheet as well as its measurement amount. This section also specifies how financial instruments gains and losses are to be presented.

The Company will add all transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability to the fair value of the financial asset or financial liability. These adjustments were previously recorded in deferred charges. Transaction costs added to the fair value of the financial asset or financial liability will be amortized using the effective interest method.

o Section 3865 - "Hedges" replaces Accounting Guideline 13 - "Hedging Relationships" and EIC 128 - "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments" and specifies how hedge accounting is to be applied and what disclosures are necessary when hedge accounting is applied.

Adoption of this standard will require the Company to record all of its derivative financial instruments on the balance sheet at fair value, including those designated as hedges. Designated hedges are currently not recognized on the balance sheet but are disclosed in the notes to the financial statements. The adjustment to recognize the designated hedges on the balance sheet will be recorded as an adjustment to the opening balance of retained earnings or accumulated other comprehensive income, as appropriate.

Subsequently, if the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk are recognized in the consolidated statements of earnings each period. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income ("OCI") each period and are recognized in the consolidated statements of earnings when the hedged item is recognized. Therefore, ineffective portions of changes in the fair value of hedging instruments are recognized in net earnings immediately for both fair value and cash flow hedges.

Adoption of these standards will have the following estimated effects on the Company's consolidated balance sheet as at January 1, 2007:

($ millions)	
Decrease future income tax asset	$ (62)
Increase current portion of other long-term assets	$ 193
Decrease other long-term assets	$ (16)
Decrease long-term debt	$ (72)
Increase future income tax liability	$ 18
Increase retained earnings	$ 10
Increase foreign currency translation adjustment	$ 13
Increase accumulated other comprehensive income	$ 146

OUTLOOK

The Company continues to implement its strategy of maintaining a large portfolio of varied projects, which the Company believes will enable it, 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 2007 to average between 315,000 bbl/d and 360,000 bbl/d of crude oil and NGLs and between 1,594 mmcf/d and 1,664 mmcf/d of natural gas.

The forecasted capital expenditures in 2007 are currently expected to be as follows:

($ millions)	2007 Forecast
North America natural gas	$ 1,111
North America crude oil and NGLs	1,350
North Sea	521
Offshore West Africa	114
Property acquisitions and midstream	16
	3,112
Horizon Project Phase 1 construction (1)	2,610
Capitalized interest and other items	397
Horizon Project Phases 2/3 engineering	109
Canadian Natural Upgrader engineering	5
Total	$ 6,233

(1) Forecast to be in the range of $2,410 million to $2,810 million, the final level of expenditure will be dependent upon the ability of certain contractors to advance portions of their efforts from 2008 into 2007 as well as the extent of any realized cost pressures on certain isolated portions of the Horizon Project.

NORTH AMERICA NATURAL GAS

The 2007 North America natural gas drilling program is highlighted by the high-grading of the Company's natural gas asset base, including the properties acquired through the ACC acquisition, as follows:

(number of wells)	2007 Forecast
Northeast British Columbia	58
Northwest Alberta	123
Northern Plains	172
Southern Plains	70
Total	423

NORTH AMERICA CRUDE OIL AND NGLS

The 2007 North America crude oil drilling program is highlighted by continued development of its Primrose thermal projects, Pelican Lake, and a strong conventional heavy program, as follows:

(number of wells)	2007 Forecast
Conventional heavy crude oil	369
Thermal heavy crude oil	58
Light crude oil	107
Pelican Lake crude oil	132
Total	666

The Company has reduced forecasted natural gas capital for 2007 by approximately 40% from 2006 levels due to the shift in capital allocation to higher return crude oil projects in the near term. Allocation of natural gas capital between existing and newly acquired ACC lands will be the result of a high-grading process focusing on the highest return projects. No changes to the long-term natural gas plans of the Company are being contemplated.

The Company continues the disciplined development of its heavy crude oil resources. Crude oil capital has been maintained with 2006 levels as the Company continues to develop long-term production growth projects at Pelican Lake and in-situ oilsands at Primrose and Kirby.

THE HORIZON PROJECT

The final level of capital expenditure on the Horizon Project will be dependent upon the ability of certain of the contractors to advance portions of their efforts from 2008 into 2007, as well as the extent of any realized cost pressures on certain isolated portions of the project.

The 2007 capital forecast for the Horizon Project targets the completion of

most major plants with the commissioning process to be substantially underway. The Ore Preparation Plant and Tailings Systems are targeted to be mechanically complete and ready to commission

with the majority of utilities and offsite systems operational. The Upgrader is targeted to be nearing completion, with half of the related plants completed. A total of 156 stratigraphic test wells are targeted to be drilled on the Horizon Project leases during 2007.

NORTH SEA

The 2007 capital forecast for the North Sea includes drilling 7.4 producer wells and 7.2 service wells. The development of the Lyell Field is targeted for completion in late 2007.

OFFSHORE WEST AFRICA

The 2007 capital forecast for Offshore West Africa includes drilling 3.0 producer wells and 1.2 service well at West Espoir.

SENSITIVITY ANALYSIS (1)

The following table is indicative of the annualized sensitivities of cash flow from operations and net earnings from changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2006, and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only; all other variables are held constant.

<TABLE>
<CAPTION>

	CASH FLOW FROM OPERATIONS ($ millions)	CASH FLOW FROM OPERATIONS ($/share, basic)	NET EARNINGS ($ millions)	NET EARNINGS ($/share, basic)
<S>	<C>	<C>	<C>	<C>
Price changes				
Crude oil - WTI US$1.00/bbl (2)				
Excluding financial derivatives	$ 116	$ 0.22	$ 81	$ 0.15
Including financial derivatives	$ 26-110	$ 0.05-0.21	$ 20-77	$ 0.04-0.14
Natural gas - AECO C$0.10/mcf (2)				
Excluding financial derivatives	$ 26	$ 0.05	$ 14	$ 0.03
Including financial derivatives	$ 1-8	$ 0.00-0.02	$ 2-4	$ 0.00-0.01
Volume changes				
Crude oil - 10,000 bbl/d	$ 98	$ 0.18	$ 44	$ 0.08
Natural gas - 10 mmcf/d	$ 17	$ 0.03	$ 6	$ 0.01
Foreign currency rate change				
$0.01 change in C$ in relation to US$ (2)				
Excluding financial derivatives	$ 80-82	$ 0.15	$ 23-24	$ 0.04
Interest rate change - 1%	$ 48	$ 0.09	$ 48	$ 0.09

</TABLE>

(1) The sensitivities are calculated based on 2006 fourth quarter results and exclude mark-to-market gains (losses) on risk management activities.
(2) For details of financial instruments in place, refer to note 12 to the Company's audited annual consolidated financial statements as at December 31, 2006.

<TABLE>
<CAPTION>
DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2006	2005	2004
<S>	<C>	<C>	<C>	<C>	<C>	<C>	<C>
Crude oil and NGLs (bbl/d)							
North America	222,955	234,780	233,440	249,565	235,253	221,669	206,225
North Sea	60,802	63,703	53,988	61,786	60,056	68,593	64,706
Offshore West Africa	39,905	40,369	34,237	32,354	36,689	22,906	11,558
Total	323,662	338,852	321,665	343,705	331,998	313,168	282,489
Natural gas (mmcf/d)							
North America	1,411	1,448	1,416	1,594	1,468	1,416	1,330
North Sea	17	17	11	16	15	19	50
Offshore West Africa	8	10	10	10	9	4	8
Total	1,436	1,475	1,437	1,620	1,492	1,439	1,388
Barrels of oil equivalent (boe/d)							
North America	458,158	476,143	469,440	515,313	479,891	457,695	427,936
North Sea	63,589	66,426	55,790	64,490	62,558	71,651	73,093
Offshore West Africa	41,280	42,042	35,922	33,961	38,275	23,614	12,806
Total	563,027	584,611	561,152	613,764	580,724	552,960	513,835

</TABLE>

<TABLE>
<CAPTION>
PER UNIT RESULTS (1)

Q1	Q2	Q3	Q4	2006	2005	2004
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Crude oil and NGLs ($/bbl)						
Sales price (2)	$ 43.79	$ 60.05	$ 62.55	$ 47.27	$ 53.65	$ 46.86	$ 37.99
Royalties	3.48	5.14	5.11	4.10	4.48	3.97	3.16
Production expense	11.33	11.92	13.47	12.32	12.29	11.17	10.05
Netback	$ 28.98	$ 42.99	$ 43.97	$ 30.85	$ 36.88	$ 31.72	$ 24.78
Natural gas ($/mcf)						
Sales price (2)	$ 8.30	$ 6.16	$ 5.83	$ 6.66	$ 6.72	$ 8.57	$ 6.50
Royalties	1.70	1.11	1.11	1.26	1.29	1.75	1.35
Production expense	0.80	0.80	0.84	0.86	0.82	0.73	0.67
Netback	$ 5.80	$ 4.25	$ 3.88	$ 4.54	$ 4.61	$ 6.09	$ 4.48
Barrels of oil equivalent ($/boe)						
Sales price (2)	$ 46.30	$ 50.36	$ 51.21	$ 43.91	$ 47.92	$ 48.77	$ 38.45
Royalties	6.44	5.80	5.75	5.62	5.89	6.82	5.37
Production expense	8.46	8.85	10.01	9.16	9.14	8.21	7.35
Netback	$ 31.40	$ 35.71	$ 35.45	$ 29.13	$ 32.89	$ 33.74	$ 25.73

</TABLE>
(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.

NETBACK ANALYSIS

($/boe) (1)	2006	2005	2004
Sales price (2)	$ 47.92	$ 48.77	$ 38.45
Royalties	5.89	6.82	5.37
Production expense (3)	9.14	8.21	7.35
Netback	32.89	33.74	25.73
Midstream contribution (3)	(0.23)	(0.26)	(0.26)
Administration (4)	0.85	0.75	0.66
Interest, net	0.66	0.74	1.01
Realized risk management activities	6.27	5.13	2.52
Realized foreign exchange (gain) loss	(0.06)	(0.15)	0.02
Taxes other than income tax - current	1.04	1.01	1.12
Current income tax - North America	0.68	0.50	0.53
Current income tax - North Sea	0.14	0.77	0.01
Current income tax - Offshore West Africa	0.23	0.17	0.07
Cash flow	$ 23.31	$ 25.08	$ 20.05

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.
(3) Excluding inter-segment eliminations.
(4) Restated to conform to current year presentation.

<TABLE>
<CAPTION>
TRADING AND SHARE STATISTICS

Q1	Q2	Q3	Q4	2006 TOTAL	2005 Total
<S>	<C>	<C>	<C>	<C>	<C>
TSX-C$					
Trading volume (thousands)	134,487	129,036	127,022	118,390	508,935	637,992
Share price ($/share)						
High	$ 73.91	$ 72.70	$ 63.30	$ 63.50	$ 73.91	$ 62.00
Low	$ 57.75	$ 50.78	$ 47.28	$ 45.49	$ 45.49	$ 24.28
Close	$ 64.90	$ 61.72	$ 50.94	$ 62.15	$ 62.15	$ 57.63
Market capitalization at December 31 ($ millions)					$ 33,431	$ 30,910
Shares outstanding (thousands)					537,903	536,348
NYSE - US$						
Trading volume (thousands)	78,836	102,472	101,438	119,163	401,909	251,554
Share price ($/share)						
High	$ 64.38	$ 63.93	$ 56.68	$ 55.48	$ 64.38	$ 54.05
Low	$ 49.62	$ 45.67	$ 42.38	$ 40.29	$ 40.29	$ 19.74
Close	$ 55.39	$ 55.38	$ 45.58	$ 53.23	$ 53.23	$ 49.62
Market capitalization at December 31 ($ millions)					$ 28,633	$ 26,614
Shares outstanding (thousands)					537,903	536,348

</TABLE>

MANAGEMENT'S REPORT

The accompanying consolidated financial statements and all other information contained elsewhere in this annual report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies described in the accompanying notes. Where necessary, management has made informed judgements and estimates in accounting for transactions that were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared in accordance with Canadian generally accepted accounting principles appropriate in the circumstances. The financial information presented 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 and recorded, 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 audit and provide their independent audit opinions on the following:

o the Company's consolidated financial statements as at December 31, 2006;

o the effectiveness of the Company's internal control over financial reporting as at December 31, 2006; and

o management's assessment of the Company's internal control over financial reporting as at December 31, 2006.

Their report is presented with the consolidated financial statements.

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

<TABLE>
<S> <C> <C>
/s/ Steve W. Laut /s/ Douglas A. Proll /s/ Randall S. Davis
- ---------- ---------- ----------
Steve W. Laut Douglas A. Proll, CA Randall S. Davis, Ca
President & Chief Chief Financial Officer & Vice President, Finance & Accounting
Operating Officer Senior Vice-President, Finance
</TABLE>

March 15, 2007
Calgary, Alberta, Canada

MANAGEMENT'S ASSESSMENT OF INTERNAL
CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company as defined in Rule 15(d)-15(f) under the United States Securities Exchange Act of 1934, as amended.

Management, together with the Company's President and Chief Operating Officer and the Company's Chief Financial Officer and Senior Vice-President, Finance, performed an assessment of the Company's internal control over financial reporting based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Based on the assessment, management, together with the Company's President and Chief Operating Officer and the Company's Chief Financial Officer and Senior Vice-President, Finance, has concluded that the Company's internal control over financial reporting is effective as at December 31, 2006. Management recognizes that all internal control systems have inherent limitations. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management's assessment of the effectiveness of the Company's internal control over financial reporting as at December 31, 2006, has been audited by PricewaterhouseCoopers LLP, independent auditors, as stated in their report presented with the audited consolidated financial statements.

/s/ Steve W. Laut	/s/ Douglas A. Proll
Steve W. Laut	Douglas A. Proll, CA
President & Chief Operating Officer Senior Vice-President, Finance	Chief Financial Officer &

March 15, 2007
Calgary, Alberta, Canada

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Canadian Natural Resources Limited

We have completed an integrated audit of the consolidated financial statements and internal control over financial reporting of Canadian Natural Resources Limited (the "Company") as of December 31, 2006 and audits of its December 31, 2005 and December 31, 2004 consolidated financial statements. Our opinions, based on our audits, are presented below.

CONSOLIDATED FINANCIAL STATEMENTS

We have audited the accompanying consolidated balance sheets of the Company as of December 31, 2006 and December 31, 2005, and the related consolidated statements of earnings, retained earnings and cash flows for each of the three years in the period ended December 31, 2006. These 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 audit of the Company's financial statements as of December 31, 2006 and for the year then ended in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). We conducted our audits of the Company's financial statements as of December 31, 2005 and for each of the two years in the period ended December 31, 2005 in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2006 and December 31, 2005 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006 in accordance with Canadian generally accepted accounting principles.

INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited management's assessment, included in the accompanying management's assessment of internal control over financial reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control - -Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006 is fairly stated, in all material respects, based on criteria established in Internal Control -- Integrated Framework issued by the COSO. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal

control over financial reporting as of December 31, 2006 based on criteria established in Internal Control -- Integrated Framework issued by the COSO.

/s/ PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada

March 15, 2007

ADDITIONAL DISCLOSURE

DISCLOSURE CONTROLS AND PROCEDURES

As of the end of the registrant's fiscal year ended December 31, 2006, an evaluation of the effectiveness of Canadian Natural's "disclosure controls and procedures" (as such term is defined in Rules 13a-15(c) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") was carried out by Canadian Natural's management with the participation of Canadian Natural's principal executive officer and principal financial officer. Based upon the evaluation, Canadian Natural's principle executive officer and principal financial officer have concluded that as of the end of the fiscal year, Canadian Natural's disclosure controls and procedures are effective to ensure that information required to be disclosed by the registrant in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms and (ii) accumulated and communicated to the registrant's management, including its principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

It should be noted that while Canadian Natural's principal executive officer and principal financial officer believe that Canadian Natural's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect Canadian Natural's disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The required disclosure is included in the "Management Report" that accompanies the Registrant's Management's Discussion and Analysis for the fiscal year ended December 31, 2006, filed as part of this Annual Report on Form 40-F.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

The required disclosure is included in the "Auditors' Report" that accompanies the Registrant's Management's Discussion and Analysis for the fiscal year ended December 31, 2006, filed as part of this Annual Report on Form 40-F.

CHANGES IN INTERNAL CONTROLS OVER FINANCIAL REPORTING

During the fiscal year ended December 31, 2006, there were no changes in Canadian Natural's internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, Canadian Natural's internal controls over financial reporting.

NOTICES PURSUANT TO REGULATION BTR

None

AUDIT COMMITTEE FINANCIAL EXPERT

The Board of Directors of Canadian Natural has determined that Ms. C.M. Best qualifies as an "audit committee financial expert" (as defined in paragraph 8(b) of General Instruction B to the Form 40-F) serving on its Audit Committee. Ms. C.M. Best is, as are all members of the Audit Committee of the Board of Directors of Canadian Natural, "independent" as such term is defined in the rules of the New York Stock Exchange.

CODE OF ETHICS

Canadian Natural has a long-standing Code of Integrity, Business Ethics and Conduct (the "Code of Ethics"), which covers such topics as employment standards, conflict of interest, the treatment of confidential information and trading in Canadian Natural's shares, to ensure that Canadian Natural's business is conducted in a consistently legal and ethical manner. Each director and all employees, including each member of senior management and more specifically the principal executive officer, the principal financial officer and the principal accounting officer, are required to abide by the Code of Ethics. The Nominating and Corporate Governance Committee periodically reviews the Code of Ethics to ensure it addresses appropriate topics and complies with regulatory requirements and recommends any appropriate changes to the Board for approval.

Any waivers of or amendments to the Code of Ethics must be approved by the Board of Directors and will be appropriately disclosed. No amendments, waivers or implicit waivers to the Code of Ethics in whole or in part were asked for or granted to any director, senior officer or employee in 2006.

The Code of Ethics is available through the System for Electronic Document and Analysis and Retrieval (SEDAR) at www.sedar.com. Requests for copies can also be made by contacting: Bruce E. McGrath, Corporate Secretary, Canadian Natural Resources Limited, 2500-855 2nd Street, S.W., Calgary, Alberta, Canada T2P 4J8.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

PricewaterhouseCoopers LLP ("PwC") has been the auditor of Canadian Natural since Canadian Natural's inception. The aggregate amounts billed by PwC for each of the last two fiscal years for audit fees, audit-related fees, tax fees and all other fees, excluding expenses, are set forth below.

AUDIT FEES: The aggregate fees billed for each of the last two fiscal years of Canadian Natural ending December 31, 2006 and December 31, 2005, for professional services rendered by PwC for the audit of its internal controls and annual consolidated financial statements in connection with statutory and regulatory filings or engagements for those fiscal years, unaudited reviews of the first, second and third quarters of its interim consolidated financial statements and audits of certain of Canadian Natural's subsidiary companies' annual financial statements were not to exceed C$3,126,287 for 2006 and were C$1,227,835 for 2005.

AUDIT-RELATED FEES: The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ending December 31, 2006 and December 31, 2005, for audit-related services by PwC consisting of debt covenant compliance and Crown Royalty Statements, were not to exceed $121,353 for 2006 and were $266,923 for 2005. Canadian Natural's Audit Committee approved all of these audit-related services.

TAX FEES: The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ending December 31, 2006 and December 31, 2005, for professional services rendered by PwC for tax-related services related to expatriate personal tax and compliance as well as other corporate tax return matters provided in 2006 were not to exceed $134,025 for 2006 and were $39,331 for 2005. Canadian Natural's Audit Committee approved all of these tax-related services.

ALL OTHER FEES: The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ending December 31, 2006 and December 31, 2005 for other services were not to exceed $9,516 for 2006 and were $7,290 for 2005. The fees for other services paid in 2006 related to accessing resource materials through PwC's accounting literature library. Canadian Natural's Audit Committee approved all of the noted services.

AUDIT COMMITTEE PRE-APPROVAL POLICIES AND PROCEDURES:

The Audit Committee's duties and responsibilities include the review and approval of fees to be paid to the independent auditors, scope and timing of the audit and other related services rendered by the independent auditors. The Audit Committee also reviews and approves the independent auditor's annual audit plan, including scope, staffing, locations and reliance upon management

and internal audit department prior to the commencement of the audit and reviews and approves proposed non-audit services to be provided by the independent auditors, except those non-audit services prohibited by legislation. Canadian Natural did not rely on the de minimis exemption provided by paragraph (c)(7)(i)(c) of Rule 2.01 of Regulation S-X in 2006.

OFF-BALANCE SHEET ARRANGEMENTS

Canadian Natural does not have any off-balance sheet arrangements that have or are reasonably likely to have an effect on its results of operations or financial condition. See page 63 of Canadian Natural's Management's Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2006, filed herewith, under the caption "Commitments and Off Balance Sheet Arrangements".

CONTRACTUAL OBLIGATIONS

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, Canadian Natural has entered into various commitments that will have an impact on Canadian Natural's future operations. These commitments primarily relate to debt repayments, operating leases relating to office space and offshore FPSOs and drilling rigs, and firm commitments for gathering, processing and transmission services, as well as expenditures relating to asset retirement obligations. As at December 31, 2006, no entities were consolidated under the Canadian Institute of Chartered Accountants Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes Canadian Natural's commitments as at December 31, 2006:

<TABLE>
<CAPTION>

($ millions)	2007	2008	2009	2010	2011	Thereafter
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Product transportation and pipeline (1)	$ 213	$ 193	$ 134	$ 123	$ 99	$ 1,042
Offshore equipment operating leases (2)	$ 77	$ 52	$ 52	$ 52	$ 50	$ 131
Offshore drilling	$ 73	$ 83	$ 12	$ 12	$ 4	$ 4
Asset retirement obligations (3)	$ 3	$ 3	$ 3	$ 3	$ 4	$ 4,480
Long-term debt (4)	$ 161	$ 45	$ 3,876	$ -	$ 466	$ 3,713
Office leases	$ 26	$ 32	$ 33	$ 34	$ 22	$ -
Electricity and other	$ 51	$ 10	$ 17	$ 18	$ 1	$ -

</TABLE>

(1) CANADIAN NATURAL ENTERED INTO A 25 YEAR PIPELINE TRANSPORTATION AGREEMENT COMMENCING IN 2008, RELATED TO FUTURE CRUDE OIL PRODUCTION. THE AGREEMENT IS RENEWABLE FOR SUCCESSIVE 10-YEAR PERIODS AT CANADIAN NATURAL'S OPTION. DURING THE INITIAL TERM, ANNUAL TOLL PAYMENTS BEFORE OPERATING COSTS WILL BE APPROXIMATELY $35 MILLION.

(2) OFFSHORE EQUIPMENT OPERATING LEASES ARE PRIMARILY COMPRISED OF OBLIGATIONS RELATED TO FPSOS. DURING 2006, CANADIAN NATURAL ENTERED INTO AN AGREEMENT TO LEASE AN ADDITIONAL FPSO COMMENCING IN 2008, IN CONNECTION WITH THE PLANNED OFFSHORE DEVELOPMENT IN GABON, OFFSHORE WEST AFRICA. THE NEW FPSO LEASE AGREEMENT CONTAINS CANCELLATION PROVISIONS AT THE OPTION OF CANADIAN NATURAL, SUBJECT TO ESCALATING TERMINATION PAYMENTS THROUGHOUT 2007 TO A MAXIMUM OF US$395 MILLION.

(3) AMOUNTS REPRESENT MANAGEMENT'S ESTIMATE OF THE FUTURE UNDISCOUNTED PAYMENTS TO SETTLE ASSET RETIREMENT OBLIGATIONS RELATED TO RESOURCE PROPERTIES, FACILITIES, AND PRODUCTION PLATFORMS, BASED ON CURRENT LEGISLATION AND INDUSTRY OPERATING PRACTICES. AMOUNTS DISCLOSED FOR THE PERIOD 2007 - 2011 REPRESENT THE MINIMUM REQUIRED EXPENDITURES TO MEET THESE OBLIGATIONS. ACTUAL EXPENDITURES IN ANY PARTICULAR YEAR MAY EXCEED THESE MINIMUM AMOUNTS.

(4) THE LONG-TERM DEBT REPRESENTS PRINCIPAL REPAYMENTS ONLY. NO DEBT REPAYMENTS ARE REFLECTED FOR $2,782 MILLION OF REVOLVING BANK CREDIT FACILITIES DUE TO THE EXTENDABLE NATURE OF THE FACILITIES.

In 2005, the Board of Directors of Canadian Natural approved the construction costs for Phase 1 of the Horizon Project, with an approved budget of $6.8 billion. Cumulative construction spending to December 31, 2006 was approximately $4.0 billion. Final construction costs for Phase 1 may differ from the approved budget due to changes in the final scope and timing of completion of the project, and/or inflationary cost pressures.

IDENTIFICATION OF THE AUDIT COMMITTEE

Canadian Natural has a separately designated standing audit committee established in accordance with section 3(a)(58)(A) of the Exchange Act. The members of the Audit Committee are Messrs. G. A. Filmon, G. D. Giffin, D. A. Tuer and Ms. C.M. Best, who chairs the Audit Committee.

NEW YORK STOCK EXCHANGE DISCLOSURE

PRESIDING DIRECTOR AT MEETINGS OF NON-MANAGEMENT DIRECTORS

Canadian Natural schedules executive sessions at each regularly scheduled Board of Directors meeting in which Canadian Natural's "non-management directors" (as that term is defined in the rules of the New York Stock Exchange) meet without management participation. Mr. G. D. Giffin serves as the presiding director (the "Presiding Director") at such sessions and in his absence the non-management directors appoint a Presiding Director from among the non-management directors.

COMMUNICATION WITH NON-MANAGEMENT DIRECTORS

Shareholders may send communications to Canadian Natural's non-management directors by writing to the Presiding Director, c/o Bruce E. McGrath, Corporate Secretary, Canadian Natural Resources Limited, 2500, 855 - 2nd Street S.W., Calgary, Alberta, T2P 4J8. Communications will be referred to the Presiding Director for appropriate action. The status of all outstanding concerns addressed to the Presiding Director will be reported to the board of directors as appropriate.

CORPORATE GOVERNANCE GUIDELINES

In accordance with Section 303A.09 of the NYSE Listed Company Manual, Canadian Natural has adopted a set of corporate governance guidelines, which are available in print AT no charge to any shareholder who requests them. Requests for copies of the corporate governance guidelines should be made by contacting: Bruce E. McGrath, Corporate Secretary, Canadian Natural Resources Limited, 2500-855 2nd Street, S.W., Calgary, Alberta, Canada T2P 4J8. The corporate governance guidelines are attached as a schedule to the Information Circular for the Annual General Meeting of Shareholders which is available through the System for Electronic Document and Analysis and Retrieval (SEDAR) at www.sedar.com

BOARD COMMITTEE CHARTERS

The charters of Canadian Natural's Audit Committee, Nominating and Corporate Governance Committee and Compensation Committee are available in print at no charge to any shareholder who requests them. Requests for copies of these documents should be made by contacting: Bruce E. McGrath, Corporate Secretary, Canadian Natural Resources Limited, 2500-855 2nd Street, S.W., Calgary, Alberta, Canada T2P 4J8. The Charter of Canadian Natural's Audit Committee is also attached as a schedule to Canadian Natural's Annual Information Form for year ending December 31, 2006, which forms part of this Form 40-F. The Annual Information Form is also available through the System for Electronic Document and Analysis and Retrieval (SEDAR) at www.sedar.com

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

UNDERTAKING

Canadian Natural 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.

CONSENT TO SERVICE OF PROCESS

Canadian Natural 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.

Any change to the name or address of the agent for service of process of Canadian Natural shall be communicated promptly to the Commission by an amendment to the Form F-X referencing the file number of the relevant registration statement.

SIGNATURES

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

Dated this 28th day of March, 2007.

CANADIAN NATURAL RESOURCES LIMITED

By: /s/ Steve W. Laut

Name: Steve W. Laut
Title: President and Chief Operating Officer

Documents filed as part of this report:

EXHIBIT INDEX

EXHIBIT NO. DESCRIPTION

1. Supplementary Oil & Gas Information for the fiscal year ended December 31, 2006.

2. Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934.

3. Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934.

4. Certification of Chief Executive Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).

5. Certification of Chief Financial Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).

6. Consent of PricewaterhouseCoopers LLP, independent chartered accountants.

7. Consent of Sproule Associates Limited, independent petroleum engineering consultants.

8. Consent of Ryder Scott Company, independent petroleum engineering consultants.

9. Consent of GLJ Petroleum Consultants, independent petroleum engineering consultants.