CANADIAN NATURAL RESOURCES LTD
Form 40-F
March 25, 2011

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, 2010 Commission File Number: 333-12138

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

ALBERTA, CANADA
(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-Eighth 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.

1,090,848,136 Common Shares outstanding as of December 31, 2010

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 [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (s.232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes ___ 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 (File No. 333-162270) under the Securities Act of 1933.

All dollar amounts in this Annual Report on Form 40-F are expressed in Canadian dollars. As of March 18, 2011, the noon buying rate for Canadian Dollars as expressed by the Federal Reserve Bank of New York was US$1.00 equals C$ 0.9846.

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, 2010.

B. Audited Annual Financial Statements

Canadian Natural's audited consolidated financial statements for the years ended December 31, 2010 and 2009, including the auditor's report with respect thereto. For a reconciliation of important differences between Canadian and United States generally accepted accounting principles, see Note 17 of the notes to the audited consolidated financial statements.

C. Management's Discussion and Analysis

Canadian Natural's Management's Discussion and Analysis for the year ended December 31, 2010.

Supplementary Oil & Gas Information

For Canadian Natural's Supplementary Oil & Gas Information for the year ended December 31, 2010, see Exhibit 1 of this Annual Report on Form 40-F.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2010

March 25, 2011

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DEFINITIONS AND ABBREVIATIONS

The following are definitions and selected abbreviations used in this Annual Information Form:

"API" means the specific gravity measured in degrees on the American Petroleum Institute scale

"ARO" means Asset Retirement Obligation

"bbl" or "barrel" means 34.972 Imperial gallons or 42 US gallons

"Bcf" means one billion cubic feet

"bbl/d" means barrels per day

"BOE" means barrel of oil equivalent

"BOE/d" means barrel of oil equivalent per day

"CO2" means carbon dioxide

"CO2e" means carbon dioxide equivalents

"Canadian GAAP" means Generally Accepted Accounting Principles in Canada

"Canadian Natural Resources Limited", "Canadian Natural", "Company", or "Corporation" means Canadian Natura Resources Limited and includes, where applicable, reference to subsidiaries of and partnership interests held by Canadian Natural Resources Limited and its subsidiaries

"CBM" means Coal Bed Methane

"crude oil, NGLs and natural gas" includes all of the Company's light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), synthetic crude oil, natural gas and natural gas liquids reserves

"development well" means a well drilled inside the established limits of an oil or gas reservoir or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive

"dry well" means an exploratory, development, or extension well that proves to be incapable of producing either crude oil or natural gas in sufficient quantities to justify completion as an oil or gas well

"exploratory well" means a well that is not a development well, a service well or a stratigraphic test well

"extension well" means a well that is drilled to test if a known reservoir extends beyond what had previously been believed to be the outer reservoir perimeter

"FPSO" means Floating Production, Storage and Offloading vessel

"GHG" means Greenhouse Gas

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

"Horizon" means Horizon Oil Sands

"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

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“MMBOE” means one million barrels of oil equivalent

“MMcf” means one million cubic feet

“MMcf/d” means one million cubic feet per day

“MMcfe” means one million cubic feet equivalent

“MM$” means one million Canadian dollars

“NGLs” means Natural Gas Liquids

“net acres” refers to gross acres multiplied by the percentage working interest therein owned

“net asset value” means the discounted pre-tax value of forecast price proved and probable crude oil and natural gas reserves (net of future development costs and associated material well abandonment costs) plus the value of core unproved land, less net debt

“net wells” refers to gross wells multiplied by the percentage working interest therein owned by the Company

“NYSE” means New York Stock Exchange

“productive well” means an exploratory, development or extension well that is not dry

“proved property” means a property or part of a property to which reserves have been specifically attributed

“PRT” means Petroleum Revenue Tax

“SAGD” means Steam-Assisted Gravity Drainage

“SCO” means Synthetic Crude Oil

“SEC” means United States Securities and Exchange Commission

“service well” means a well drilled or completed for the purpose of supporting production in an existing field and are drilled for the specific purposes of gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion

“stratigraphic test well” means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition and are ordinarily drilled without the intention of being completed for hydrocarbon production

“TSX” means Toronto Stock Exchange

“unproved property” means a property or part of a property to which no reserves have been specifically attributed

“UK” means the United Kingdom

“US” means United States

"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

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "int "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "se expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, and other guidance provided throughout this Annual Information Form ("AIF") including the information in the "Exploration and Development Activities" section, constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands resumption of production and future expansion, Primrose, Pelican Lake, Olowi Field (Offshore Gabon), the Kirby In situ Oil Sands Project, the Keystone Pipeline US Gulf coast expansion, and the construction and operation of the North West Redwater bitumen refinery upgrader also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year if necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks and the reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil and natural gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected difficulties in mining, extracting or upgrading the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses. The Company's operations have been, and in the future may be, affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, 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 the "Risks Factors" section of this AIF. Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements.

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Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements should circumstances or Management'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 are 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 conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

For the year ended December 31, 2010 the Company retained Independent Qualified Reserves Evaluators ("Evaluators"), Sproule Associates Limited and Sproule International Limited (together as "Sproule") and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company's proved and proved plus probable reserves with an effective date of December 31, 2010 and a preparation date of February 14, 2011. Sproule evaluated the North America and International crude oil, NGLs and natural gas reserves. GLJ evaluated the Horizon SCO reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements. In previous years, Canadian Natural had been granted an exemption order from the securities regulators in Canada that allowed substitution of U.S. Securities Exchange Commission ("SEC") requirements for certain NI 51-101 reserves disclosures. This exemption expired on December 31, 2010. As a result, the 2010 reserves disclosure is presented in accordance with Canadian reporting requirements using forecast prices and escalated costs.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States Financial Accounting Standards Board Topic 932 "Extractive Activities - Oil and Gas" in the Company's annual Form 40-F filed with the SEC in the "Supplementary Oil and Gas Information" section of the Company's Annual Report which is incorporated herein by reference.

Special Note Regarding Non-GAAP Financial Measures

This Annual Information Form 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 ("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 non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with Canadian GAAP in the "Financial Highlights" section the Company's MD&A which is incorporated by reference into this document.

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CORPORATE STRUCTURE

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 November 2, 2006, pursuant to a Purchase and Sale Agreement, the Company acquired all of the outstanding shares of Anadarko Canada Corporation (“ACC”), a subsidiary of Anadarko Petroleum Corporation. On November 3, 2006, ACC and a wholly owned subsidiary of the Company, 1266701 Alberta Ltd. amalgamated to form ACC-CNR Resources Corporation. On January 1, 2007, ACC-CNR Resources Corporation and the Company amalgamated pursuant to the Business Corporations Act (Alberta) under the name Canadian Natural Resources Limited.

On January 1, 2008 Ranger Oil (International) Ltd., 764968 Alberta Inc., CNR International (Norway) Limited, Renata Resources Inc. and the Company amalgamated pursuant to the Business Corporations Act (Alberta) under the name Canadian Natural Resources Limited.

The main operating subsidiaries and partnerships of the Company, percentage of voting securities owned either directly or indirectly, and their jurisdictions of incorporation are as follows:

	Jurisdiction of Incorporation	% Ownership
Subsidiary		
CanNat Energy Inc.	Delaware	100
CNR (ECHO) Resources Inc.	Alberta	100
CNR International (U.K.) Investments Limited	England	100
CNR International (U.K.) Limited	England	100
CNR International (Côte d’Ivoire) SARL	Côte d’Ivoire	100
CNR International (Olowi) Limited	Bahamas	100
Horizon Construction Management Ltd.	Alberta	100
Partnership		

Canadian Natural Resources	Alberta	100
Canadian Natural Resources Northern Alberta Partnership	Alberta	100
Canadian Natural Resources 2005 Partnership	Alberta	100

Canadian Natural, as the managing partner, CNR (ECHO) Resources Inc. and Canadian Natural Resources 2005 Partnership are the partners of Canadian Natural Resources, a general partnership. Canadian Natural, as the managing partner, CNR (ECHO) Resources Inc., Canadian Natural Resources and Canadian Natural Resources 2005 Partnership are partners of Canadian Natural Resources Northern Alberta Partnership, a general partnership. Canadian Natural, as the managing partner, and CNR (ECHO) Resources Inc. are the partners of Canadian Natural Resources 2005 Partnership.

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In the ordinary course of business, Canadian Natural restructures its subsidiaries and partnerships to maintain efficient operations and to facilitate acquisitions and divestitures.

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

2008

On January 17, 2008, the Company issued US$400 million of 5 year 5.15% unsecured notes maturing February 1, 2013, US$400 million of 10 year 5.90% unsecured notes maturing February 1, 2018 and US$400 million of 31 year 6.75% unsecured notes maturing February 1, 2039 pursuant to a US short form base shelf prospectus dated September 25, 2007.

In 2008, the Company committed 120,000 bbl/d to the Keystone Pipeline US Gulf Coast Expansion for a 20 year period, subject to regulatory approval. Concurrently the Company entered into a 20 year supply agreement with a major US refiner for 100,000 bbl/d of heavy crude oil to US Gulf Coast refineries. Deliveries under the agreements are expected to commence in 2013 contingent upon Keystone receiving the regulatory approvals for the pipeline expansion and subsequent completion of the expansion.

The Company entered into an agreement in August 2005 to obtain pipeline transportation service for Horizon. The initial term of the agreement is 25 years, which commenced on the in-service date of November 1, 2008. The twinning of the existing Alberta Oil Sands Pipeline (“AOSPL”), resulting in two parallel pipelines, one of which is dedicated to Canadian Natural, combined with the new pipeline constructed from the Horizon site down to the AOSPL Terminal (collectively, the “Horizon Pipeline”) provides crude oil transportation service for Horizon. In addition to having the option to renew the agreement for successive 10 year terms, the Company has the right to request incremental expansion of the Horizon Pipeline based upon applicable National Energy Board approved multi pipeline economics. This agreement allows the Company to gain access to major sales pipelines out of Edmonton for the Company’s SCO transportation service for Horizon, while at the same time providing significant quality benefits associated with being the only shipper on the Horizon Pipeline.

The Company completed a number of transactions in the normal course to acquire and dispose of interests in crude oil and natural gas properties for an aggregate net expenditure of $336 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.

2009

Construction of Phase 1 of Horizon was completed and commercial operations began with production averaging 50,250 bbl/day.

The Company repaid the $2,350 million remaining on the non-revolving syndicated credit facility related to the 2006 acquisition of ACC and cancelled the facility.

The Company completed a number of transactions in the normal course to acquire and dispose of interests in crude oil and natural gas properties for an aggregate net expenditure of $6 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.

2010

During the last half of 2010, the Company received regulatory approval for its Kirby In situ Oil Sands Project and the Board of Directors sanctioned Kirby Phase 1 with construction commencing in the fourth quarter 2010. First steam-in is targeted for 2013 and peak production for Phase 1 is targeted to be 40,000 bbl/d with an overall cost targeted of $1.25 Billion.

The Company completed a number of transactions in the normal course to acquire and dispose of interests in crude oil and natural gas properties for an aggregate net expenditure of $1.9 billion. 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.

2011

On January 6, 2011, the Company suspended SCO production at its Oils Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. Production will recommence once plant operating capacity is restored and all necessary regulatory and operating approvals are received.

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The Company believes that it has adequate insurance coverage to mitigate all significant property damage related losses. The Company also maintains business interruption coverage, subject to a waiting period, which it believes will mitigate operating losses related to on-going operations.

In January 2010, the Company announced that, together with North West Upgrading Inc. ("NWU"), it had submitted a joint proposal to the Alberta Government to construct and operate a bitumen refinery near Redwater, Alberta. This proposal was submitted in response to a request for proposal under the Alberta Royalty Framework's Bitumen Royalty in Kind ("BRIK") program. Canadian Natural agreed, subject to a number of conditions, to acquire 50% of the assets of NWU and form a partnership to construct and operate the facility. On February 16, 2011 Canadian Natural and NWU entered into a partnership agreement to move forward with detailed engineering regarding the construction and operation of the facility. In addition, the partnership has entered into an agreement to process bitumen supplied by the Government of Alberta under the BRIK initiative. Provided the project is sanctioned by the Board of Directors following detailed engineering, Phase 1 is targeted to process 50,000 bbl/d of bitumen to finished products with an integrated CO2 management solution. The proposed facility can be expanded in two additional identical phases of 50,000 bbl/d of bitumen, provided economics justify the investment. Canadian Natural has agreed to supply 12,500 bbl/d of its own bitumen production to Phase 1 of the proposed facility.

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, and natural gas 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 initiates, operates and maintains a large working interest in a majority of the prospects in which it participates. Canadian Natural's objectives are to increase crude oil and natural gas production, reserves, cash flow and net asset value on a per common share basis through the development of its existing crude oil and natural gas properties and through the discovery and/or acquisition of new reserves.

The Company has a full complement of management, technical and support staff to pursue these objectives. As at December 31, 2010, the Company had the following full time equivalent permanent employees:

North America, Exploration and Development	2,779
North America, Oil Sands Mining and Upgrading	1,516
North Sea	331
Offshore West Africa	45
Total Company	4,671

The Company focuses on exploiting its core properties and actively maintaining cost controls. Whenever possible Canadian Natural maintains 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, light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), SCO and NGLs. The Company's operations are centered 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 33% of 2010 production. Virtually all of the Company's natural gas and NGLs production is located in the Canadian provinces of Alberta, British Columbia and

Saskatchewan and is marketed in Canada and the United States. Light and medium crude oil and NGLs, representing 18% of 2010 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 heavy crude oil accounting for 15% of 2010 production, Pelican Lake heavy crude oil accounting for 6% of 2010 production, and our bitumen (thermal oil) accounting for 14% of 2010 production are in the provinces of Alberta and Saskatchewan. SCO from our oil sands mining operations in Northern Alberta accounts for approximately 14% of 2010 production. Midstream assets, comprised of three crude oil pipelines and an electricity co-generation facility, provide cost effective infrastructure supporting the heavy oil and bitumen operations.

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A. ENVIRONMENTAL MATTERS

The Company carries out its activities in compliance with all applicable regional, national and international regulations and industry standards. Environmental specialists in Canada and the UK track performance to numerous environmental performance indicators, 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. 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 internal environmental compliance audit and inspection program of its operating facilities; a 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; a due diligence program related to groundwater monitoring; an active program related to preventing spills and reclaiming spill sites; a solution gas conservation program; a program to replace the majority of fresh water for steaming with brackish water; water management programs to improve efficiency of use, recycle rates and water storage; environmental planning for all projects to assess environmental impacts and to implement avoidance and mitigation programs; reporting for environmental liabilities; a program to optimize efficiencies at the Company's operating facilities; continued evaluation of new technologies to reduce environmental impacts; implementation of a tailings management plan; and CO2 reduction programs including the injection of CO2 into tailings and for use in enhanced oil recovery. The Company has also established operating standards in the following areas: exercising care with respect to all waste produced through effective waste management plans; using water-based, environmentally friendly drilling muds whenever possible; and minimizing produced water volumes offshore through cost-effective measures. In 2010, Canadian Natural expanded the environmental liability reduction program with the abandonment of over 1,200 inactive wells. In addition, reclamation was initiated at many of these sites with the eventual goal of reclamation certification. Further, decommissioning of inactive facilities and clean up of active facilities was conducted to address environmental liabilities at operating assets. Canadian Natural participates in both the Canadian federal and provincial regulated GHG emissions reporting programs. The Company continues to quantify annual GHG emissions for internal reporting purposes. The Company has participated in the Canadian Association of Petroleum Producers ("CAPP") Responsible Canadian Energy Program since 2000. Canadian Natural continues to invest in people, proven and new technologies, facilities and infrastructure to recover and process crude oil and natural gas resources efficiently and in an environmentally sustainable manner.

The Company through CAPP is working with legislators and regulators as they develop and implement new GHG emissions laws and regulations. Internally, the Company is pursuing an integrated emissions reduction strategy to ensure it is able to comply with existing and future emissions reduction requirements for both GHG's and air pollutants (such as sulphur dioxide and oxides of nitrogen). The Company continues to develop strategies that will enable it to deal with the risks and opportunities associated with new GHG and air emissions 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 focus on reducing GHG emissions through improved efficiency, and on trading mechanisms to ensure compliance with requirements now in effect. 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 the Company's environmental work plan and are operated within all regulatory standards and guidelines. The Company strategy for managing GHG emissions is based on six core principles: improving energy conservation and efficiency; reducing emission intensity; developing and adopting innovative technology and supporting associated research and development; trading capacity, both domestically and globally; offsetting emissions; and considering life cycle costs of emission reductions in decision-making about project development.

The Company continues to implement flaring, venting, fuel and solution gas conservation programs. In 2010 the Company completed approximately 174 gas conservation projects in its primary heavy oil operations, resulting in a reduction of 1.35 million tonnes/year of CO_2e. Over the past five years the Company has spent over $61.9 million in its primary heavy crude oil and in situ oil sands operations to conserve the equivalent of over 8.3 million tonnes of CO_2e. The Company also monitors

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the performance of its compressor fleet which is continually modified and optimized for maximum efficiency. These programs also influence and direct the Company's plans for new projects and facilities. Horizon has incorporated advancements in technology to further reduce 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 CO2 capture and the sequestration of CO2 in oil sands tailings. In its North Sea operations the Company continues to focus on its flare reduction program, with a number of initiatives completed in 2010, including replacement of valves and installation of a new turbine exhaust.

B. 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 crude oil and natural gas industry in Canada operates under government legislation and regulations, which govern exploration, development, production, refining, marketing, transportation, prevention of waste and other activities.

The Company's Canadian properties are primarily located in Alberta, British Columbia, Saskatchewan, and Manitoba. 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 are 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.

An Alberta 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. 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 and are not subject to escalating rentals 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 their respective province. Government royalties are payable on crude oil, NGLs and natural gas production from leases owned by the province. The royalties are determined by regulation and are generally calculated as a percentage of production varied by a number of different factors including selling prices, production levels, recovery methods, transportation and processing costs, location and date of discovery.

The Alberta Government implemented changes to the Alberta Royalty Framework ("ARF") effective January 1, 2009. The ARF includes a number of changes to royalty rates for natural gas, crude oil, and oil sands production. Under the ARF, royalties payable vary according to commodity prices and the productivity of wells. Initial changes to the Alberta royalty regime under the ARF included the implementation of a sliding scale for oil sands royalties ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout, depending on benchmark crude oil pricing.

During 2010, the Government of Alberta modified the crude oil and natural gas royalty rates. These changes included:

§ Effective May 1, 2010, an extension of the period subject to the 5% maximum royalty rate for CBM and shale gas wells to the first 36 months after start of production, subject to volume limits of 750 MMcfe for CBM and no volume limits for shale gas.

§ Effective May 1, 2010, an extension of the period subject to the 5% maximum royalty rate for horizontal natural gas and crude oil wells. The period for horizontal natural gas wells is extended to the first 18 months after start of production, and volumes of 500 MMcfe. Limits on production months and volumes for crude oil will be set according to the measured depth of the wells.

§ Effective January 1, 2011, a reduction in the maximum royalty rate to 5% on new natural gas and crude oil wells for the first 12 months after the start of production, subject to volume limits of 500 MMcfe and 50,000 BOE respectively.

§ Effective January 1, 2011, a reduction in the maximum royalty rate for crude oil from 50% to 40% and a reduction in the maximum royalty rate for conventional and unconventional natural gas from 50% to 36%.

Modifications were also made to the natural gas deep drilling program, including changes to depth requirements. The Government of Alberta also announced changes to the price components of oil and gas royalty formulas to reduce the royalty rate at prices higher than $85.00 per bbl and $5.25 per GJ respectively.

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In addition to government royalties, the Company is subject to federal and provincial income taxes in Canada at a combined rate of approximately 28% after allowable deductions for 2010.

During 2007, the Canadian Federal Government enacted income tax rate changes which decrease the Federal corporate income tax rate over a five year period. The income tax rate in 2010 was 18%, and is scheduled to decrease to 16.5% in 2011 and 15% in 2012.

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 PRT of 50% 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 production 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. There is no PRT on profits of decommissioned fields subsequently redeveloped, subject to certain conditions being met.

The Company is subject to UK Corporation Tax ("CT") on its UK profits at a current rate of 30%. An additional Supplementary Charge Tax of 20% is charged on crude oil and natural gas profits but excludes any deduction for financing costs. The deduction for crude oil and natural gas expenditures on capital items is generally 100% in the year incurred. PRT paid is deductible for CT purposes.

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 in Block CI-26 and the Baobab Field in Block CI-40, Offshore Côte d'Ivoire, are subject to Production Sharing Agreements ("PSA") that deem tax or royalty payments to the Government are met from the Government's share of profit oil. The current Corporate Income Tax rate in Côte d'Ivoire is 25% which is applicable to non PSA income.

The Olowi Field (Offshore Gabon) is also under the terms of a PSA which deems tax or royalty payments to the Government are met from the Government's share of profit oil. The current Corporate Income Tax rate is 35% which is applicable to non PSA income.

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C. COMPETITIVE FACTORS

The energy industry is highly competitive in all aspects of the business including the exploration for and the development of new sources of supply, the construction and operation of crude oil and natural gas pipelines and related facilities, the acquisition of crude oil and natural gas interests, the transportation and marketing of crude oil, NGLs, natural gas, and electricity and the attraction and retention of skilled personnel. The Company's competitors include both integrated and non integrated crude oil and natural gas companies as well as other petroleum products and energy sources.

D. 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. Significant declines 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, industrial demand, prices of alternate sources of energy, and the import of liquefied natural gas. 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, including but not limited to Horizon, Primrose, Pelican Lake, the Kirby In situ Oil Sands Project, and international projects, or curtailment in production at some properties, or result in unutilized long-term transportation commitments, all of which could have a material adverse effect on the Company's financial condition.

Approximately 35% of the Company's 2010 production on a BOE basis was primary heavy crude oil, Pelican Lake heavy crude oil, and bitumen (thermal oil). The market prices for these products differ from the established market indices for light and medium grades of crude oil due principally to the quality difference and the mix of product obtained in the refining process referred to as the "quality differential". 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 quality differentials are uncertain and a significant increase in the heavy crude oil differentials could have a material adverse effect on the Company's financial condition.

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

Operational Risk

Exploring for, producing, upgrading and transporting crude oil, NGLs and natural gas 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, interruption of operations and loss of production. In addition to the foregoing, the Horizon operations are also subject to loss of production, potential shutdowns and increased production costs due to the integration of the various component parts, as well as severe winter weather conditions.

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 the Company's financial condition.

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 may require the Company to address and mitigate the effect of its activities on the environment. Increasingly stringent laws and regulations, including any new regulations the US may impose to limit purchases of crude oil in favour of less energy intensive sources, may have a material adverse effect on the Company's financial condition.

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.

Completion Risk

Canadian Natural has a variety of exploration, development and construction projects underway at any given time. Project delays may result in delayed revenue receipts and cost overruns may result in projects being uneconomic. The Company's ability to complete projects is dependent on general business and market conditions as well as other factors beyond our control including the availability of skilled labour and manpower, the availability and proximity of pipeline capacity, weather, environmental and regulatory matters, ability to access lands, availability of drilling and other equipment, and availability of processing capacity.

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, royalties, 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.

Access to Sources of Liquidity

The ability of the Company to fund current and future capital projects and carry out our business plan is dependent on our ability to raise capital in a timely manner under favourable terms and conditions and is impacted by our ability to maintain investment grade credit ratings and the condition of the capital and credit markets. In addition, changes in credit ratings may affect the Company's ability to, and the associated costs, of entering into ordinary course derivative or hedging transactions, as well as entering into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

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Greenhouse Gas and Other Air Emissions

There are a number of unresolved issues in relation to Canadian federal and provincial GHG regulatory requirements. Key among them is the form of regulation, an appropriate common facility emissions level, availability and duration of compliance mechanisms and resolution of federal/provincial harmonization agreements. The Company continues to pursue GHG emissions reduction initiatives including solution gas conservation, compressor optimization to improve fuel gas efficiency, CO2 capture and sequestration in oil sands tailings, CO2 capture and storage in association with enhanced oil recovery and participation in an industry initiative to promote an integrated CO2 capture and storage network.

Air pollutant standards and guidelines are being developed federally and provincially and the Company is participating in these discussions. Ambient air quality and sector based reductions in air emissions are being reviewed. Through participation of the Company and the industry with stakeholders, guidelines have been developed that adopt a structured process to emissions reductions that is commensurate with technological development and operational requirements.

In Canada, the Federal Government has indicated its intent to develop regulations that would be in effect in the near term to address industrial GHG emissions, as part of the national GHG reduction target. The Federal Government will also be developing a comprehensive management system for air pollutants.

In Alberta, GHG regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO2e annually. Two of the Company's facilities, the Primrose/Wolf Lake in situ heavy crude oil facilities and the Hays sour natural gas plant, are subject to compliance under the regulations. The British Columbia carbon tax is currently being assessed at $20/tonne of CO2e on fuel consumed and gas flared in the province. This rate is scheduled to increase to $25/tonne on July 1, 2011, and to $30/tonne by July 1, 2012. As part of its involvement with the Western Climate Initiative, British Columbia has also announced that certain upstream oil and gas facilities will be included in a regional cap and trade system beginning in 2012. It is estimated that eight facilities in British Columbia will be included under the cap and trade system, based on a proposed requirement of 25 kilotonnes of CO2e annually. Saskatchewan is expected to release GHG regulations in 2011 that may likely require the North Tangleflags in situ heavy oil facility to meet a reduction target for its GHG emissions. In the UK, GHG regulations have been in effect since 2005. In Phase 1 (2005 – 2007) of the UK National Allocation Plan, the Company operated below its CO2 allocation. In Phase 2 (2008 – 2012) the Company's CO2 allocation has been decreased below the Company's estimated current operations emissions. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO2 emissions at its major facilities and on trading mechanisms to ensure compliance with requirements now in effect.

Legislation to regulate GHGs in the United States through a cap and trade system is pending. In the absence of legislation, the US Environmental Protection Agency ("EPA") is intending to regulate GHGs under the Clean Air Act. This EPA action would be subject to legal and political challenges. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the United States. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oils with higher emissions intensity.

The additional requirements of enacted or proposed GHG regulations on the Company's operations will increase capital expenditures and production expense, especially those related to Horizon and the Company's other existing and planned large oil sands projects. Depending on the legislation enacted, this may have an adverse effect on the Company's financial condition.

Hedging Activities

In response to fluctuations in commodity prices, foreign exchange, and interest rates, the Company may utilize various derivative financial instruments and physical sales contracts to manage its exposure under a defined hedging program. The terms of these arrangements may limit the benefit to the Company of favourable changes in these factors and may also result in royalties being paid on a reference price which is higher than the hedged price. There is also increased exposure to counterparty credit risk.

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

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jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of a court in Canada or the United States.

Canadian Natural's arrangement for the exploration and development of crude oil and natural gas properties in Canada and the UK sector of the North Sea differs distinctly from its arrangement for the exploration and development in other 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 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.

Other Business Risks

Other business risks which may negatively impact the Company's financial condition include labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner, the dependency on third party operators for some of the Company's assets, timing and success of integrating the business and operations of acquired companies, credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, risk of litigation, regulatory issues, risk of increases in government taxes and changes to the royalty regime and risk to the Company's reputation resulting from operational activities that may cause personal injury, property damage or environmental damage. The majority of the Company's assets are held in one or more corporate subsidiaries or partnerships. In the event of the liquidation of any corporate 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.

E. FORM 51-101F1 STATEMENT OF RESERVES DATA AND OTHER INFORMATION

For the year ended December 31, 2010 the Company retained Independent Qualified Reserves Evaluators ("Evaluators"), Sproule Associates Limited and Sproule International Limited (together as "Sproule") and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company's proved and proved plus probable reserves with an effective date of December 31, 2010 and a preparation date of February 14, 2011. Sproule evaluated the North America and International crude oil, NGLs and natural gas reserves. GLJ evaluated the Horizon SCO reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements. In previous years, Canadian Natural had been granted an exemption order from the securities regulators in Canada that allowed substitution of U.S. Securities Exchange Commission ("SEC") requirements for certain NI 51-101 reserves disclosures. This exemption expired on December 31, 2010. As a result, the 2010 reserves disclosure is presented in accordance with Canadian reporting requirements using forecast prices and escalated costs.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with Sproule and GLJ as to the Company's reserves.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States Financial Accounting Standards Board Topic 932 "Extractive Activities - Oil and Gas" in the Company's annual Form 40-F filed with the SEC in the "Supplementary Oil and Gas Information" section of the Company's Annual Report on pages 86 to 93 which is incorporated herein by reference.

The estimates of future net revenue presented in the tables below do not represent the fair market value of the reserves.

There is no assurance that the price and cost assumptions contained in the forecast case will be attained and variances could be material. The recovery and reserves estimates of crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee the estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater or less than the estimate provided herein.

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Summary of Company Gross Oil and Gas Reserves
As of December 31, 2010
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	93	74	153	219	1,804	2,864	44	2,864
Developed Non-Producing	4	20	1	13	-	180	2	70
Undeveloped	13	66	85	687	128	1,048	17	1,171
Total Proved	110	160	239	919	1,932	4,092	63	4,105
Probable	40	57	109	783	956	1,430	20	2,203
Total Proved plus Probable	150	217	348	1,702	2,888	5,522	83	6,308
North Sea								
Proved								
Developed Producing	78					12		80
Developed Non-Producing	16					37		22
Undeveloped	158					29		163
Total Proved	252					78		265
Probable	124					29		129
Total Proved plus Probable	376					107		394
Offshore West Africa								
Proved								
Developed Producing	96					87		110
Developed Non-Producing	-					-		-
Undeveloped	24					5		25
Total Proved	120					92		135
Probable	57					46		65
Total Proved plus Probable	177					138		200
Total Company								
Proved								
Developed Producing	267	74	153	219	1,804	2,963	44	3,055
Developed Non-Producing	20	20	1	13	-	217	2	92
Undeveloped	195	66	85	687	128	1,082	17	1,358
Total Proved	482	160	239	919	1,932	4,262	63	4,505
Probable	221	57	109	783	956	1,505	20	2,397
Total Proved plus Probable	703	217	348	1,702	2,888	5,767	83	6,902

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Summary of Company Net Oil and Gas Reserves
As of December 31, 2010
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	79	62	120	164	1,483	2,561	30	2,365
Developed Non-Producing	3	16	-	12	-	150	2	58
Undeveloped	11	57	62	535	114	927	13	946
Total Proved	93	135	182	711	1,597	3,638	45	3,369
Probable	33	47	72	600	764	1,232	14	1,735
Total Proved plus Probable	126	182	254	1,311	2,361	4,870	59	5,104
North Sea								
Proved								
Developed Producing	78					12		80
Developed Non-Producing	16					37		22
Undeveloped	158					29		163
Total Proved	252					78		265
Probable	124					29		129
Total Proved plus Probable	376					107		394
Offshore West Africa								
Proved								
Developed Producing	82					72		94
Developed Non-Producing	-					-		-
Undeveloped	19					4		20
Total Proved	101					76		114
Probable	48					37		54
Total Proved plus Probable	149					113		168
Total Company								
Proved								
Developed Producing	239	62	120	164	1,483	2,645	30	2,539
Developed Non-Producing	19	16	-	12	-	187	2	80
Undeveloped	188	57	62	535	114	960	13	1,129
Total Proved	446	135	182	711	1,597	3,792	45	3,748
Probable	205	47	72	600	764	1,298	14	1,918
Total Proved plus Probable	651	182	254	1,311	2,361	5,090	59	5,666

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NOTES

1. "Gross reserves" are the Company's working interest share of reserves before deduction of royalties and without including any royalty interests of the Company.

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

3. "Reserves" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as at a given date, based on analysis of drilling, geological, geophysical, and engineering data, with the use of established technology and under specified economic conditions which are generally accepted as being reasonable.

Reserves are classified according to the degree of certainty associated with the estimates:

— "Proved reserves" are those reserves which can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

— "Probable reserves" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

— "Developed reserves" are reserves that are expected to be recovered from (i) existing wells and installed facilities or, if the facilities have not been installed, that would involve a low expenditure (compared to the cost of drilling a well) to put the reserves on production, and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. The developed category may be subdivided into producing and non-producing.

— "Undeveloped reserves" are reserves that are expected to be recovered from known accumulations with 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 directly offsetting development spacing areas that are reasonably certain of production when drilled unless reliable technology exists that establishes reasonable certainty of economic producibilty at greater distances.

4. The reserve evaluation involved data supplied by the Company with respect to geological and engineering data, adjustments for product quality, heating value and transportation, interests owned, royalties payable, operating costs, capital costs and contractual commitments. This data was found by the Evaluators to be reasonable.

A report on reserves data by the Evaluators is provided in Schedule "A" to this Annual Information Form. A report by the Company's management and directors on crude oil, NGLs and natural gas disclosure is provided in Schedule "B" to this Annual Information Form.

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Summary of Net Present Values of Future Net Revenue Before Income Taxes
As of December 31, 2010
Forecast Prices and Costs

MM$	Discount @ 0%	Discount @ 5%	Discount @10%	Discount @ 15%	Discount @ 20%	Unit Value Discounted at 10%/year $/BOE (1)
North America						
Proved						
Developed Producing	111,052	49,965	32,979	25,699	21,590	13.94
Developed Non-Producing	2,327	1,672	1,308	1,071	902	22.55
Undeveloped	34,256	18,161	10,291	6,204	3,815	10.88
Total Proved	147,635	69,798	44,578	32,974	26,307	13.23
Probable	99,744	41,508	19,172	9,706	5,205	11.05
Total Proved plus Probable	247,379	111,306	63,750	42,680	31,512	12.49
North Sea						
Proved						
Developed Producing	2,605	2,225	1,938	1,717	1,541	24.23
Developed Non-Producing	929	735	597	496	420	27.14
Undeveloped	6,736	4,222	2,755	1,855	1,278	16.90
Total Proved	10,270	7,182	5,290	4,068	3,239	19.96
Probable	7,250	3,995	2,476	1,674	1,211	19.19
Total Proved plus Probable	17,520	11,177	7,766	5,742	4,450	19.71
Offshore West Africa						
Proved						
Developed Producing	4,449	2,920	2,173	1,752	1,487	23.12
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	1,101	668	449	325	247	22.45
Total Proved	5,550	3,588	2,622	2,077	1,734	23.00
Probable	2,908	1,538	919	604	428	17.02
Total Proved plus Probable	8,458	5,126	3,541	2,681	2,162	21.08
Total Company						
Proved						
Developed Producing	118,106	55,110	37,090	29,168	24,618	14.61
Developed Non-Producing	3,256	2,407	1,905	1,567	1,322	23.81
Undeveloped	42,093	23,051	13,495	8,384	5,340	11.95
Total Proved	163,455	80,568	52,490	39,119	31,280	14.00
Probable	109,902	47,041	22,567	11,984	6,844	11.77
Total Proved plus Probable	273,357	127,609	75,057	51,103	38,124	13.25

(1) Unit values are based on Company net reserves.

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Summary of Net Present Values of Future Net Revenue After Income Taxes
As of December 31, 2010
Forecast Prices and Costs

MM$	Discount @ 0%	Discount @ 5%	Discount @10%	Discount @ 15%	Discount @ 20%
North America					
Proved					
Developed Producing	85,609	39,349	26,287	20,603	17,356
Developed Non-Producing	1,737	1,237	961	783	656
Undeveloped	25,600	13,227	7,181	4,036	2,202
Total Proved	112,946	53,813	34,429	25,422	20,214
Probable	74,348	30,455	13,637	6,530	3,176
Total Proved plus Probable	187,294	84,268	48,066	31,952	23,390
North Sea					
Proved					
Developed Producing	892	767	672	599	541
Developed Non-Producing	364	288	234	194	164
Undeveloped	2,221	1,417	935	634	440
Total Proved	3,477	2,472	1,841	1,427	1,145
Probable	2,449	1,369	854	580	419
Total Proved plus Probable	5,926	3,841	2,695	2,007	1,564
Offshore West Africa					
Proved					
Developed Producing	4,449	2,920	2,173	1,752	1,487
Developed Non-Producing	-	-	-	-	-
Undeveloped	1,101	668	449	325	247
Total Proved	5,550	3,588	2,622	2,077	1,734
Probable	2,908	1,538	919	604	428
Total Proved plus Probable	8,458	5,126	3,541	2,681	2,162
Total Company					
Proved					
Developed Producing	90,950	43,036	29,132	22,954	19,384
Developed Non-Producing	2,101	1,525	1,195	977	820
Undeveloped	28,922	15,312	8,565	4,995	2,889
Total Proved	121,973	59,873	38,892	28,926	23,093
Probable	79,705	33,362	15,410	7,714	4,023
Total Proved plus Probable	201,678	93,235	54,302	36,640	27,116

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Additional Information Concerning Future Net Revenue

The following table summarizes the undiscounted future net revenue as at December 31, 2010 using forecast prices and costs.

Total Future Net Revenue (Undiscounted)

(MM$)	North America Proved	North America Proved Plus Probable	North Sea Proved	North Sea Proved Plus Probable	Offshore West Africa Proved	Offshore West Africa Proved Plus Probable	Total Proved	Total Proved Plus Probable
Revenue	404,158	611,574	26,178	40,861	8,132	12,012	438,468	664,447
Royalties	75,135	120,503	-	-	10	15	75,145	120,518
Operating Costs	144,452	183,549	10,924	17,307	2,069	2,286	157,445	203,142
Development Costs	36,582	59,735	4,849	5,876	496	1,204	41,927	66,815
Abandonment (1)	354	408	135	158	7	49	496	615
Future Net Revenue Before Income Taxes	147,635	247,379	10,270	17,520	5,550	8,458	163,455	273,357
Income Taxes	34,689	60,085	6,793	11,594	-	-	41,482	71,679
Future Net Revenue After Income Taxes(2)	112,946	187,294	3,477	5,926	5,550	8,458	121,973	201,678

(1) The evaluation of reserves includes only abandonment costs for future drilling locations that have been assigned reserves

(2) Future net revenue is prior to provision for interest, general and administrative expenses and the impact of any risk management activities.

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The following table summarizes the future net revenue by production group as at December 31, 2010 using forecast prices and costs.

Future Net Revenue By Production Group

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) (MM$)	Unit Value(1) ($/bbl)	Unit Value(1) ($/Mcf)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	10,885	22.13	
	Primary Heavy Crude Oil (including solution gas and other by-products)	3,600	26.38	
	Pelican Lake Heavy Crude Oil (including solution gas and other by-products)	3,862	21.10	
	Bitumen (Thermal Oil)	10,429	14.66	
	Synthetic Crude Oil	14,493	9.08	
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	9,221		2.44
	Total	52,490	16.83	2.44
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	15,041	21.08	
	Primary Heavy Crude Oil (including solution gas and other by-products)	4,999	27.19	
	Pelican Lake Heavy Crude Oil (including solution gas and other by-products)	5,209	20.37	
	Bitumen (Thermal Oil)	16,462	12.55	
	Synthetic Crude Oil	21,804	9.24	
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	11,542		2.29
	Total	75,057	15.55	2.29

(1) Unit values are based on Company net reserves.

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Pricing Assumptions

The crude oil, NGLs and natural gas reference pricing and the inflation and exchange rates used in the preparation of reserves and related future net revenue estimates are as per the Sproule price forecast dated December 31, 2010. The following is a summary of the Sproule price forecast.

	Crude Oil and NGLs					Natural Gas			Inflation Rates
	WTI Cushing Oklahoma(1)	WCS(2)	Edmonton Par(3)	North Sea Brent(4)	Edmonton C5+(5)	Henry Hub Louisiana	AECO(6)	BC Westcoast Station 2(7)	
YEAR	(US$/bbl)	(C$/bbl)	(C$/bbl)	(US$/bbl)	(C$/bbl)	(US$/MMbtu)	(C$/MMbtu)	(C$/MMbtu)	%/Year
FORECAST									
2011	88.40	80.04	93.08	87.15	95.32	4.44	4.04	3.98	1.5
2012	89.14	80.71	93.85	87.87	96.11	5.01	4.66	4.60	1.5
2013	88.77	78.48	93.43	87.48	95.68	5.32	4.99	4.93	1.5
2014	88.88	76.70	93.54	87.58	95.79	6.80	6.58	6.52	1.5
2015	90.22	77.86	94.95	88.89	97.24	6.90	6.69	6.63	1.5
Thereafter	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	1.5

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

(2) "WCS" refers to the price of Western Canadian Select at Hardisty, Alberta; reference price used in the preparation of heavy oil and bitumen reserves.

(3) "Edmonton Par" refers to the price of light gravity (40° API), low sulphur content crude oil at Edmonton, Alberta; reference price used in the preparation of light and medium crude oil and SCO reserves.

(4) Reference price used in the preparation of North Sea and Offshore West Africa light oil reserves.

(5) Edmonton C5+ refers to pentanes plus at Edmonton, Alberta; reference price used in the preparation of NGL reserves; also used in determining the diluent costs associated with heavy oil and bitumen (thermal oil) reserves.

(6) Reference price used in the preparation of North America (excluding British Columbia) natural gas reserves.

(7) Reference price used in the preparation of British Columbia natural gas reserves.

The forecast prices and costs 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 above and adjusted for quality and transportation on an individual property basis. Capital and operating costs are escalated at 1.5 % per year.

The Company's 2010 average pricing, excluding risk management activities, was $77.84 for light and medium crude oil, $62.04 for primary heavy crude oil, $61.69 for Pelican Lake heavy crude oil, $59.55 for bitumen (thermal oil), $77.89 for SCO, $59.83 for NGLs and for $4.08 for natural gas.

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Reconciliation of Company Gross Reserves by Product
As of December 31, 2010
Forecast Prices and Costs

PROVED

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2009	100	116	251	732	1,871	3,731	46	3,738
Discoveries	-	1	-	-	-	69	2	15
Extensions	1	20	2	47	-	217	5	111
Infill Drilling	3	25	-	-	-	21	1	33
Improved Recovery	-	-	1	-	-	2	3	4
Acquisitions	12	2	-	109	-	446	7	204
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	1	(94)	(1)	(16)
Technical Revisions	6	30	(1)	64	93	144	6	222
Production	(12)	(34)	(14)	(33)	(33)	(444)	(6)	(206)
December 31, 2010	110	160	239	919	1,932	4,092	63	4,105
North Sea								
December 31, 2009	265					72		277
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	-					-		-
Technical Revisions	(1)					10		1
Production	(12)					(4)		(13)
December 31, 2010	252					78		265
Offshore West Africa								
December 31, 2009	136					99		152
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-

Economic Factors	-					-		-
Technical Revisions	(5)					(1)		(5)
Production	(11)					(6)		(12)
December 31, 2010	120					92		135
Total Company								
December 31, 2009	501	116	251	732	1,871	3,902	46	4,167
Discoveries	-	1	-	-	-	69	2	15
Extensions	1	20	2	47	-	217	5	111
Infill Drilling	3	25	-	-	-	21	1	33
Improved Recovery	-	-	1	-	-	2	3	4
Acquisitions	12	2	-	109	-	446	7	204
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	1	(94)	(1)	(16)
Technical Revisions	-	30	(1)	64	93	153	6	218
Production	(35)	(34)	(14)	(33)	(33)	(454)	(6)	(231)
December 31, 2010	482	160	239	919	1,932	4,262	63	4,505

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PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2009	41	39	106	595	969	1,271	15	1,977
Discoveries	-	-	-	-	-	19	1	4
Extensions	-	8	2	61	-	98	2	89
Infill Drilling	3	10	1	-	-	14	-	16
Improved Recovery	-	-	-	-	-	-	-	-
Acquisitions	4	1	-	163	-	110	1	187
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	-	-	-	-	(3)	(26)	-	(7)
Technical Revisions	(8)	(1)	-	(36)	(10)	(55)	1	(63)
Production	-	-	-	-	-	-	-	-
December 31, 2010	40	57	109	783	956	1,430	20	2,203
North Sea								
December 31, 2009	127					24		131
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	-					-		-
Technical Revisions	(3)					5		(2)
Production	-					-		-
December 31, 2010	124					29		129
Offshore West Africa								
December 31, 2009	63					45		71
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	-					-		-
Technical Revisions	(6)					1		(6)
Production	-					-		-
December 31, 2010	57					46		65

Total Company								
December 31, 2009	231	39	106	595	969	1,340	15	2,179
Discoveries	-	-	-	-	-	19	1	4
Extensions	-	8	2	61	-	98	2	89
Infill Drilling	3	10	1	-	-	14	-	16
Improved Recovery	-	-	-	-	-	-	-	-
Acquisitions	4	1	-	163	-	110	1	187
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	-	-	-	-	(3)	(26)	-	(7)
Technical Revisions	(17)	(1)	-	(36)	(10)	(49)	1	(71)
Production	-	-	-	-	-	-	-	-
December 31, 2010	221	57	109	783	956	1,505	20	2,397

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PROVED PLUS PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2009	141	155	357	1,327	2,840	5,002	61	5,715
Discoveries	-	1	-	-	-	88	3	19
Extensions	1	28	4	108	-	315	7	200
Infill Drilling	6	35	1	-	-	35	1	49
Improved Recovery	-	-	1	-	-	2	3	4
Acquisitions	16	3	-	272	-	556	8	391
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	-	-	-	-	(2)	(120)	(1)	(23)
Technical Revisions	(2)	29	(1)	28	83	89	7	159
Production	(12)	(34)	(14)	(33)	(33)	(444)	(6)	(206)
December 31, 2010	150	217	348	1,702	2,888	5,522	83	6,308
North Sea								
December 31, 2009	392					96		408
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	-					-		-
Technical Revisions	(4)					15		(1)
Production	(12)					(4)		(13)
December 31, 2010	376					107		394
Offshore West Africa								
December 31, 2009	199					144		223
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	-					-		-
Technical Revisions	(11)					-		(11)
Production	(11)					(6)		(12)
December 31, 2010	177					138		200

Total Company								
December 31, 2009	732	155	357	1,327	2,840	5,242	61	6,346
Discoveries	-	1	-	-	-	88	3	19
Extensions	1	28	4	108	-	315	7	200
Infill Drilling	6	35	1	-	-	35	1	49
Improved Recovery	-	-	1	-	-	2	3	4
Acquisitions	16	3	-	272	-	556	8	391
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	-	-	-	-	(2)	(120)	(1)	(23)
Technical Revisions	(17)	29	(1)	28	83	104	7	147
Production	(35)	(34)	(14)	(33)	(33)	(454)	(6)	(231)
December 31, 2010	703	217	348	1,702	2,888	5,767	83	6,902

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Additional Information Relating To Reserves Data

Undeveloped Reserves

The following tables outline the Company's gross proved undeveloped reserves and the Company's gross probable undeveloped reserves, by product type, that were first attributed in 2010 and in total. The tables do not include volumes of proved undeveloped and probable undeveloped reserves first attributed in the prior two years and in aggregate before that time. This information was not evaluated prior to 2010 due to the Company being granted an exemption order from securities regulators in Canada which allowed substitution of SEC requirements for certain NI 51-101 disclosures. This exemption expired on December 31, 2010.

2010 Proved Undeveloped Reserves

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
First Attributed	3	34	3	156	-	209	7	238
Total	195	66	85	687	128	1,082	17	1,358

2010 Probable Undeveloped Reserves

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
First Attributed	3	16	2	224	-	103	3	265
Total	146	27	43	777	862	470	6	1,939

Undeveloped reserves are reserves expected to be recovered from known accumulations and require significant expenditure to develop and make capable of production. Proved and probable undeveloped reserves were estimated by the Evaluators in accordance with the procedures and standards contained in the COGE Handbook.

Bitumen (thermal oil) accounts for 51% of the Company's total proved undeveloped BOE reserves and 40% of the total probable undeveloped BOE reserves. These undeveloped reserves are scheduled to be developed in a staged approach to align with current operational capacities and efficient capital spending commitments over the next one to forty years. These plans are continuously reviewed and updated for internal and external factors affecting planned activity.

Undeveloped reserves, for products other than bitumen, are scheduled to be developed over the next one to ten years. The Company continually reviews the economic viability and ranking of these undeveloped reserves within the total portfolio of development projects. Development opportunities are then pursued based on capital availability and allocation.

Significant Factors or Uncertainties Affecting Reserves Data

The development plan for the Company's undeveloped reserves is based on forecast price and cost assumptions. The actual prices that occur may be higher or lower resulting in certain projects being advanced or delayed.

The evaluation of reserves is a process that can be significantly affected by a number of internal and external factors. Revisions are often necessary resulting in changes in technical data acquired, historical performance, fluctuations in operating costs, development costs and product pricing, economic conditions, changes in royalty regimes and environmental regulations, and future technology improvements. See "Risk Factors" in this AIF for further information.

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Future Development Costs

The following table summarizes the undiscounted future development costs using forecast prices and costs as of December 31, 2010.

Future Development Costs (Undiscounted)

	North America		North Sea		Offshore West Africa		Total	
Year	Proved (MM$)	Proved plus Probable (MM$)	Proved (MM$)	Proved plus Probable (MM$)	Proved (MM$)	Proved plus Probable (MM$)	Proved (MM$)	Proved plus Probable (MM$)
2011	3,147	3,774	371	371	122	122	3,640	4,267
2012	3,886	5,458	366	366	30	30	4,282	5,854
2013	2,985	5,080	647	647	99	99	3,731	5,826
2014	2,330	4,808	441	441	74	258	2,845	5,507
2015	1,246	3,863	276	276	-	281	1,522	4,420
Thereafter	22,988	36,752	2,748	3,775	171	414	25,907	40,941
Total	36,582	59,735	4,849	5,876	496	1,204	41,927	66,815

Management believes internally generated cash flows, existing credit facilities and access to capital debt markets are sufficient to fund future development costs. We do not anticipate the costs of funding would make development of any property uneconomic.

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Other Oil and Gas Information

Daily Production

Set forth below is a summary of the production from crude oil, NGLs and natural gas properties for the fiscal years ended December 31, 2010 and 2009.

Region	2010 Average Daily Production Rates Crude oil & NGLs (Mbbl)	2010 Average Daily Production Rates Natural gas (MMcf)	2009 Average Daily Production Rates Crude oil & NGLs (Mbbl)	2009 Average Daily Production Rates Natural gas (MMcf)
North America				
Northeast British Columbia	5.5	305	5.5	329
Northwest Alberta	17.0	464	14.8	455
Northern Plains	229.1	296	194.6	341
Southern Plains	11.2	148	11.4	158
Southeast Saskatchewan	7.6	3	7.9	3
Oil sands Mining & Upgrading	90.9	-	50.3	-
Non-core regions	0.2	1	0.3	1
North America Total	361.5	1,217	284.8	1,287
International				
North Sea UK Sector	33.3	10	37.8	10
Offshore West Africa	30.2	16	32.9	18
International Total	63.5	26	70.7	28
Company Total	425.0	1,243	355.5	1,315

Northeast British Columbia

Significant geological variation extends throughout the productive reservoirs in this region located west of the British Columbia and Alberta border to Prince George, producing light and medium crude oil, NGLs and natural gas.

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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 shale gas plays. The 2006 acquisition of ACC significantly increased the asset base in this area. In 2010, the company drilled 15 wells of which 13 wells were tied in at Septimus, a Montney shale play, as well as built a natural gas processing plant with design capacity of 50 MMcf/d. The southern portion of this region encompasses the Company's BC Foothills assets where natural gas is produced from the deep Mississippian and Triassic aged reservoirs in this highly deformed structural area.

Northwest Alberta

This region is 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 provide a premium land base in the deep basin, multi-zone gas fairway and the Peace River Arch assets provide premium lands in a multi-zone region along with key infrastructure. In 2010, the Company purchased additional assets in the area which further complemented the asset base and operational efficiencies are expected as overlapping facilities are consolidated. 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. The south western portion of this region also contains significant Foothills assets with natural gas produced from the deep Mississippian and Triassic aged reservoirs.

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Northern Plains

This region extends just south of Edmonton north to Fort McMurray and from the Northwest Alberta area 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.

Natural gas in this region is produced from shallow, low-risk, multi-zone prospects and more recently from the Horseshoe Canyon CBM. The Company targets low-risk exploration and development opportunities and plans to expand its commercial Horseshoe Canyon CBM project. Evaluation of the potential production of CBM from the Mannville coals commenced in 2006 with the drilling of three horizontal wells. The three well pilot was deemed not commercial and the wells were suspended in 2008.

Near Lloydminster, Alberta, reserves of primary heavy crude oil (averaging 12°-14° API) and natural gas are produced through conventional vertical, slant and horizontal well bores from a number of productive horizons at depths up to 1,000 meters. 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. 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 crude oil production are the result of Crown land purchases and several acquisitions including Sceptre, Ranger and Petrovera, as well as acquisitions from Koch Exploration. Included in this area is the 100% owned ECHO Pipeline system which is a high temperature, insulated crude oil transportation pipeline that eliminates the requirement for field condensate blending. The pipeline, which has a capacity of up to 72,000 bbl/d, 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.

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 Pelican Lake heavy crude oil from the Wabasca formation with gravities of 12°-17° 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, including the 62% owned and operated Pelican Lake Pipeline. The Company is using an Enhanced Oil Recovery ("EOR") scheme through polymer flooding to increase the ultimate recoveries from the field. At the end of 2010, approximately 44% of the field had been converted to polymer injection.

Production of bitumen (thermal oil) from the 100% owned Primrose and Wolf Lake Fields located near Bonnyville, Alberta involves processes that utilize steam to increase the recovery of the bitumen (10°-11°API). The two processes employed by the Company are Cyclic Steam Stimulation ("CSS") and Steam Assisted Gravity Drainage ("SAGD"). Both recovery

processes inject steam to heat the bitumen deposits, reducing the viscosity and thereby improving its flow characteristics. There is also an infrastructure of gathering systems, a processing plant with a capacity of 119,500 bbl/d, and the 15% Company owned Cold Lake Pipeline. The Company also holds a 50% 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 1999, 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 bitumen recovery. A mature SAGD bitumen (thermal oil) project in which the Company holds a 50% interest is also in operation in the Saskatchewan portion of this region. The Regulatory application for the Kirby In situ Oil Sands Project, located approximately 85 km northeast of Lac la Biche, was approved in the third quarter 2010 and the project is expected to add 40,000 bbl/day of capacity. The Board of Directors sanctioned Kirby Phase 1 and construction commenced in the fourth quarter 2010 with first steam targeted for 2013. In 2010, the Company acquired additional lands adjacent to the Kirby Phase 1 Project and the Company expects to gain significant operating synergies through these leases and the potential for further exploitation opportunities.

In 2007, the Company received regulatory approval for its Primrose East expansion, 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 Company began construction in 2007 and first oil production was achieved in late October 2008. The expansion added 40,000 bbl/d of capacity. During the first quarter of 2009, operational issues on one of the pads caused steaming to cease on all well pads resulting in the Company switching from the steaming cycle to the production cycle ahead of schedule. The Company formalized and received approval for a plan to begin diagnostic steaming which commenced in August 2009 and continues steaming as per regulatory approval.

Southern Plains and Southeast Saskatchewan

The Southern Plains area is principally located south of the Northern Plains area to the United States border and extending into western Saskatchewan.

Reserves of natural gas, NGLs and light and medium 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 were augmented by the 2006 acquisition of ACC.

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 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. This region produces primarily light sour crude oil from as many as seven productive horizons found at depths up to 2,700 meters.

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Oil Sands Mining and Upgrading

Canadian Natural owns a 100% working interest in its Athabasca Oil Sands leases in northern Alberta, of which the main lease is subject to a 5% net carried interest in the bitumen development. Horizon is located on these leases, about 70 kilometers north of Fort McMurray. The site is accessible by a private road and private airstrip. The oil sands resource is found in the cretaceous McMurray Formation which is further subdivided into three informal members: lower, middle and upper. Most of Horizon's oil sands resource is found within the lower and middle McMurray Formation at depths ranging from 50 to 100 meters below the surface.

Horizon Oil Sands includes surface oil sands mining, bitumen extraction, bitumen upgrading and associated infrastructure. Mining of the oil sands is done using conventional truck and shovel technology. The ore is then processed through extraction and froth treatment facilities to produce bitumen, which is upgraded on-site into 34 o API SCO. The upgrader capacity is 110,000 bbl/d of SCO. The SCO is transported from the site by the Horizon Pipeline with a design capacity of 232,000 bbl/d to the Edmonton area for distribution. An on-site cogeneration plant with a design capacity of 115 MW provides power and steam for the operations.

Site clearing and pre-construction preparation activities commenced in 2004 following regulatory approvals and the Company received project sanction by the Board of Directors in February 2005, authorizing management to proceed with Phase 1 of Horizon. First SCO production was achieved during 2009 and production averaged 90,867 bbl/day in 2010.

On January 6, 2011, a fire occurred at the Company's primary upgrading coking plant. The fire was confined to one of the coke drums. Production capacity at Horizon has been suspended during the investigation and repair/rebuild to plant equipment damaged by the fire.

A preliminary assessment of the extent of damage and timelines to repair/rebuild indicate that the coke drums appear serviceable. The procurement process for all necessary replacement components and parts for the damage caused by the fire has been initiated. Based on preliminary estimates, the first set of coke drums is targeted to resume production in the second quarter of 2011 with production rates of approximately 55,000 bbl/d. The second set of coke drums is currently targeted to be on production in the third quarter of 2011.

The Company believes that it has adequate insurance coverage to mitigate all significant property damage related losses. The Company also maintains business interruption coverage, subject to a waiting period, which it believes will mitigate operating losses related to on-going operations.

The Company is reprofiling the Horizon expansion which will be executed in a staged project execution plan with project capital being allocated to several different modules. Total expenditures in 2011 are expected to range between $800 million and $1,200 million.

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United Kingdom North Sea

Through its wholly owned subsidiary CNR International (U.K.) Limited, formerly Ranger Oil (U.K.) Limited, the Company has operated in the North Sea for over 30 years and has developed a significant database, extensive operating experience and an experienced staff. In 2010, the Company produced from 13 crude oil fields.

The northerly fields are centered around the Ninian Field where the Company has an 87.1% 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% to 100%. The Company also has an interest in the Strathspey Field and 8 licences covering 12 exploration blocks and part blocks surrounding the Ninian and Murchison platforms. The Company also has a 66.5% working interest in the abandoned Hutton Field.

In the central portion of the North Sea, the Company holds an 87.6% operated working interest in the Banff Field and also owns a 45.7% operated working interest in the Kyle Field. Production from the Kyle Field is processed through the Banff FPSO facilities resulting in lower combined production costs from these fields.

The Company holds a 100% operated working interest in T-block (comprising the Tiffany, Toni and Thelma Fields).

The Company 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 2010, the Company recommenced platform drilling operations and completed one production well and one injection well at Ninian. The Company also successfully completed planned maintenance shutdowns at all of its production facilities in the year. In 2011, the Company will continue drilling operations at Ninian and also commence drilling operations at Murchison.

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Offshore West Africa

Côte d’Ivoire

The Company owns interests in two exploration licences offshore Côte d’Ivoire.

The Company has a 58.7% operated interested in the Espoir Field in Block CI-26 which is located in water depths ranging from 100 to 700 meters. Production from East Espoir commenced in 2002 and development drilling of West Espoir was completed in 2008. 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. The Facility Upgrade Project to increase processing capacity of the FPSO was completed during 2010.

The Company also has a 58% interest in the Baobab Field, identified in Block CI-40, which is eight kilometers south of the Espoir facilities. Production from the Baobab field commenced in 2005 and the Company carried out a drilling program in 2008 and 2009 to restore production from certain wells shut in due to control of sand and solids production issues.

To date, political unrest resulting from the Presidential Election in November 2010 has had minimal impact on the Company’s operations. The Company has developed contingency plans to continue Côte d’Ivoire operations from a nearby country if the situation warrants such a move.

Gabon

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The Company has a permit comprising a 92.5% operating interest in the production sharing agreement for the block containing the Olowi Field. The field is located about 20 kilometers from the Gabonese coast and in 30 meters water depth. First crude oil production was achieved on Platform C during the second quarter of 2009 and first crude oil production was achieved at Platforms A and B during 2010. Performance from the Olowi Field continues to be below expectations and, as a result, the Company recognized a pre-tax ceiling impairment of $726 million at December 31, 2010 and in late February 2011, the Company curtailed further drilling.

South Africa

The Company has a 100% operated interest in Block 11B/12B in the Pletmos Basin off the southeast coast of South Africa in water depths ranging from 200 to 2,000 meters. The Company is progressing with technical studies which may result in an exploration well being drilled in this area.

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Producing and Non Producing Crude Oil & Natural Gas Wells

Set forth below is a summary of the number of wells in which the Company has a working interest that were producing or mechanically capable of producing as of December 31, 2010.

	Natural gas wells		Crude oil wells		Total wells	
Producing	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	10,808.0	8,667.2	6,994.0	6,246.2	17,802.0	14,913.4
British Columbia	1,540.0	1,258.1	235.0	190.2	1,775.0	1,448.3
Saskatchewan	2,787.0	2,354.0	2,449.0	2,001.8	5,236.0	4,355.8
Manitoba	-	-	183.0	179.1	183.0	179.1
Total Canada	15,135.0	12,279.3	9,861.0	8,617.3	24,996.0	20,896.6
United States	4.0	0.4	2.0	0.3	6.0	0.7
North Sea UK Sector	2.0	0.1	109.0	92.0	111.0	92.1
Offshore West Africa						
Gabon	-	-	22.0	12.9	22.0	12.9
Côte d’Ivoire	-	-	13.0	12.0	13.0	12.0
Total	15,141.0	12,279.8	10,007.0	8,734.5	25,148.0	21,014.3

Set forth below is a summary of the number of wells in which the Company has a working interest that were not producing or not mechanically capable of producing as of December 31, 2010.

	Natural gas wells		Crude oil wells		Total wells	
Non Producing	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	4,106.0	3,308.5	5,639.0	5,135.6	9,745.0	8,444.1
British Columbia	1,001.0	815.0	303.0	251.6	1,304.0	1,066.6
Saskatchewan	389.0	338.8	2,048.0	1,738.8	2,437.0	2,077.6
Manitoba	1.0	1.0	21.0	19.7	22.0	20.7
Northwest Territories	25.0	6.2	2.0	0.4	27.0	6.6
Total Canada	5,522.0	4,469.5	8,013.0	7,146.1	13,535.0	11,615.6
United States	1.0	0.1	3.0	0.5	4.0	0.6
North Sea UK Sector	-	-	12.0	11.3	12.0	11.3
Offshore West Africa						
Gabon	-	-	-	-	-	-
Côte d’Ivoire	-	-	8.0	4.7	8.0	4.7
Total	5,523.0	4,469.6	8,036.0	7,162.6	13,559.0	11,632.2

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Properties With No Attributed Reserves

The following table summarizes the Company’s landholdings as at December 31, 2010.

Region (thousands of acres)	Proved Properties		Unproved Properties		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	%
North America							
Northeast British Columbia	980	805	3,095	2,389	4,075	3,194	78
Northwest Alberta	1,193	904	2,201	1,810	3,394	2,714	80
Northern Plains	2,769	2,365	7,176	6,497	9,945	8,862	89
Southern Plains	1,686	1,462	1,134	1,012	2,820	2,474	88
Southeast Saskatchewan	126	114	113	106	239	220	92
Thermal in situ Oil Sands	71	71	820	717	891	788	88
Oil Sands Mining & Upgrading	18	18	63	63	81	81	100
Non-core regions	25	7	1,361	537	1,386	544	39
North America Total	6,868	5,746	15,963	13,131	22,831	18,877	83
International							
North Sea UK Sector	68	57	159	128	227	185	82
Offshore West Africa							
Côte d’Ivoire	10	6	92	53	102	59	58
Gabon	3	3	149	138	152	140	92
South Africa	-	-	4,002	4,002	4,002	4,002	100
International Total	81	66	4,402	4,321	4,483	4,386	98
Company Total	6,949	5,812	20,365	17,452	27,314	23,263	85

Where the Company holds interests in different formations under the same surface area pursuant to separate leases, the acreage for each lease is included in the gross and net amounts.

Canadian Natural has approximately 1.15 million net acres attributed to our North America properties which are currently expected to expire by December 31, 2011.

Significant Factors or Uncertainties Relevant To Properties With No Attributed Reserves

The Company’s unproved property holdings are diverse and located in the North America and International regions. The land assets range from discovery areas where tenure to the property is held indefinitely by hydrocarbon test results or production to exploration areas in the early stages of evaluation. The Company continually reviews the economic viability and ranking of these unproved properties on the basis of product pricing, capital availability and allocation and level of infrastructure development in any specific area. From this process, some properties are scheduled for economic development activities while others are temporarily held inactive, sold, swapped or allowed to expire and relinquished back to the mineral rights owner.

Forward Contracts

In the ordinary course of business, the Company has a number of delivery commitments to provide crude oil and natural gas under existing contracts and agreements. The Company has sufficient crude oil and natural gas reserves to meet these commitments.

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Additional Information Concerning Abandonment and Reclamation Costs

For 2010, the Company's capital expenditures included $179 million for abandonment expenditures (2009 - $48 million). The Company expects approximately $54 million of abandonment expenditures to be incurred over the next 3 years.

The Company's estimated undiscounted ARO at December 31, 2010 was as follows:

Estimated ARO, undiscounted ($millions)		2010		2009
North America, Exploration and Production	$	4,125	$	3,346
North America, Oil Sands Mining and Upgrading		1,479		1,485
North Sea		1,396		1,522
Offshore West Africa		232		253
		7,232		6,606
North Sea PRT recovery		(423)		(568)
	$	6,809	$	6,038

The 2010 ARO liability discounted at 10% is approximately $910 million. The abandonment and reclamation costs were not deducted in estimating the Company's future net revenue for December 31, 2010 as the reserve evaluation includes only abandonment costs for future drilling locations that have been assigned reserves. The Company expects to incur abandonment and reclamation costs on 39,395 net wells.

The estimate of ARO was based on estimates of future costs to abandon and restore 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 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 estimated to result in a PRT recovery of $423 million (2009 - $568 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 undiscounted abandonment liability to $6,809 million (2009 - $6,038 million).

2010 Costs Incurred in Crude Oil, NGLs and Natural Gas Activities

MM$	North America	North Sea	Offshore West Africa	Other	Total
Property acquisitions					
Proved	1,904	-	-	-	1,904
Unproved	141	-	-	-	141
Exploration	267	12	1	-	280
Development	2,919	96	235	3	3,253
Costs Incurred	5,231	108	236	3	5,578

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Exploration and Development Activities

Set forth below are summaries of crude oil, NGLs and natural gas drilling activities completed by the Company for the fiscal year ended December 31, 2010 by geographic region along with a general discussion of 2011 activity.

		2010 Exploratory					
		Crude Oil	Natural Gas	Dry	Service	Stratigraphic	Total
North America							
Northeast British Columbia	Gross	-	6.0	-	-	-	6.0
	Net	-	6.0	-	-	-	6.0
Northwest Alberta	Gross	5.0	32.0	2.0	-	-	39.0
	Net	4.0	29.6	2.0	-	-	35.6
Northern Plains	Gross	132.0	9.0	6.0	-	-	147.0
	Net	126.4	6.2	6.0	-	-	138.6
Southern Plains	Gross	10.0	1.0	1.0	-	-	12.0
	Net	10.0	1.0	1.0	-	-	12.0
Southeast Saskatchewan	Gross	3.0	-	1.0	-	-	4.0
	Net	3.0	-	1.0	-	-	4.0
Oil Sands Mining and Upgrading	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Non-core Regions	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
North America Total	Gross	150.0	48.0	10.0	-	-	208.0
	Net	143.4	42.8	10.0	-	-	196.2
North Sea UK Sector	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Offshore West Africa	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Company Total	Gross	150.0	48.0	10.0	-	-	208.0
	Net	143.4	42.8	10.0	-	-	196.2

		2010 Development					
		Crude Oil	Natural Gas	Dry	Service	Stratigraphic	Total
North America							
Northeast British Columbia	Gross	8.0	21.0	1.0	1.0	-	31.0
	Net	7.8	19.6	0.5	1.0	-	28.9
Northwest Alberta	Gross	16.0	21.0	6.0	-	-	43.0
	Net	10.1	13.0	4.8	-	-	27.9
Northern Plains	Gross	753.0	18.0	20.0	17.0	206.0	1,014.0
	Net	712.1	13.7	17.1	17.0	204.9	964.8
Southern Plains	Gross	20.0	4.0	1.0	1.0	-	26.0
	Net	19.0	2.7	1.0	1.0	-	23.7
Southeast Saskatchewan	Gross	41.0	-	-	2.0	-	43.0
	Net	33.1	-	-	2.0	-	35.1
Oil Sands Mining and Upgrading	Gross	-	-	-	18.0	246.0	264.0
	Net	-	-	-	18.0	246.0	264.0
Non-core Regions	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
North America Total	Gross	838.0	64.0	28.0	39.0	452.0	1,421.0
	Net	782.1	49.0	23.4	39.0	450.9	1,344.4
North Sea UK Sector	Gross	1.0	-	-	1.0	-	2.0
	Net	0.9	-	-	0.9	-	1.8
Offshore West Africa	Gross	8.0	-	-	-	-	8.0
	Net	7.1	-	-	-	-	7.1
Company Total	Gross	847.0	64.0	28.0	40.0	452.0	1,431.0
	Net	790.1	49.0	23.4	39.9	450.9	1,353.3

Total success rate excluding service and stratigraphic test wells for 2010 is 97%.

2011 North America Natural Gas Activity

The 2011 North America natural gas drilling program is highlighted by the continued high-grading of the Company's natural gas asset base as follows:

(Number of wells)	2011 Forecast
Coal bed methane and shallow	4
Conventional	24
Cardium	4
Deep	39
Foothills	1
Total	72

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2011 North America Crude Oil and NGLs Activity

The 2011 North America crude oil drilling program is highlighted by continued development of the Primrose thermal projects, Pelican Lake, and a strong primary heavy program, as follows:

(Number of wells)	2011 Forecast
Primary heavy crude oil	791
Bitumen (thermal oil)	217
Light and Medium crude oil	138
Pelican Lake heavy crude oil	40
Total	1,186

2011 Oil Sands Mining and Upgrading Activity

Construction and commissioning of the third Ore Preparation Plant, along with the associated hydro-transport pipeline is on schedule for 2011. Engineering work as originally targeted for 2011 also continues on schedule. The Company is targeting additional cost estimate information for the Horizon expansion to be complete in the second quarter of 2011.

2011 North Sea Activity

During 2011, the majority of capital expenditures will be incurred to complete necessary sustaining capital activities on North Sea platforms.

2011 Offshore West Africa Activity

During 2011, the majority of capital expenditures will be incurred on drilling and completions.

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Production Estimates

The following table illustrates the estimated 2011 gross daily proved and probable production reflected in the reserve reports as of December 31, 2010 using forecast prices and costs.

	Light And Medium Crude Oil (bbl/d)	Primary Heavy Crude Oil (bbl/d)	Pelican Lake Heavy Crude Oil (bbl/d)	Bitumen (Thermal Oil) (bbl/d)	Synthetic Crude Oil (bbl/d)	Natural Gas (MMcf/d)	Natural Gas Liquids (bbl/d)	Barrels Of Oil Equivalent (BOE/d)
PROVED								
North America	35,117	93,037	41,301	98,302	99,600	1,176	17,912	581,269
North Sea	37,443					10		39,110
Offshore West Africa	30,674					20		34,007
Total Proved	103,234	93,037	41,301	98,302	99,600	1,206	17,912	654,386
PROBABLE								
North America	1,869	8,813	958	317	5,400	51	781	26,638
North Sea	1,440					1		1,607
Offshore West Africa	1,330					-		1,330
Total Probable	4,639	8,813	958	317	5,400	52	781	29,575

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Production History

	2010 Q1	Q2	Q3	Q4	Year Ended
North America production and netbacks by product type (1)					
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	32,429	32,056	34,480	34,890	33,473
Netbacks ($/bbl)					
Sales price (2)	$ 74.99	$ 70.55	$ 68.31	$ 74.62	$ 72.10
Royalties	15.39	13.87	12.85	14.45	14.12
Production expenses	18.69	19.99	18.16	18.74	18.88
Netback	$ 40.91	$ 36.69	$ 37.30	$ 41.43	$ 39.10
Primary Heavy Crude Oil					
Average daily production (before royalties) (bbl/d)	91,145	93,896	92,650	93,269	92,746
Netbacks ($/bbl)					
Sales price (2)	$ 66.45	$ 60.26	$ 58.97	$ 62.62	$ 62.04
Royalties	11.15	10.11	9.31	15.04	11.41
Production expenses	12.93	12.03	11.78	12.24	12.24
Netback	$ 42.37	$ 38.12	$ 37.88	$ 35.34	$ 38.39
Pelican Lake Heavy Crude Oil					
Average daily production (before royalties) (bbl/d)	37,095	37,454	38,024	37,597	37,545
Netbacks ($/bbl)					
Sales price (2)	$ 66.04	$ 60.39	$ 58.44	$ 61.73	$ 61.69
Royalties (3)	10.74	-	6.92	9.86	6.94
Production expenses	10.92	10.94	10.01	10.74	10.65
Netback	$ 44.38	$ 49.45	$ 41.51	$ 41.13	$ 44.10
Bitumen (Thermal Oil)					
Average daily production (before royalties) (bbl/d)	75,954	96,133	84,709	103,598	90,159
Netbacks ($/bbl)					
Sales price (2)	$ 62.08	$ 56.53	$ 57.60	$ 62.10	$ 59.55
Royalties	10.48	11.78	10.84	14.32	12.02
Production expenses	13.25	9.75	12.87	8.96	10.99
Netback	$ 38.35	$ 35.00	$ 33.89	$ 38.82	$ 36.54
SCO					
Average daily production (before royalties) (bbl/d)	86,995	99,950	83,809	92,730	90,867
Netbacks ($/bbl)					
Sales price (2)	$ 78.76	$ 75.97	$ 75.31	$ 81.51	$ 77.89
Royalties	2.83	2.69	2.57	2.77	2.72
Production expenses	43.12	32.27	34.35	36.13	36.36
Netback	$ 32.81	$ 41.01	$ 38.39	$ 42.61	$ 38.81

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Natural gas					
Average daily production (before royalties) (MMcf/d)	1,193	1,219	1,234	1,223	1,217
Netbacks ($/Mcf)					
Sales price (2)	$ 5.20	$ 3.85	$ 3.70	$ 3.50	$ 4.05
Royalties	0.41	0.25	0.10	0.06	0.20
Production expenses	1.17	1.03	1.04	1.02	1.06
Netback	$ 3.62	$ 2.57	$ 2.56	$ 2.42	$ 2.79
Natural Gas Liquids					
Average daily production (before royalties) (bbl/d)	15,827	16,044	17,315	17,345	16,639
Netbacks ($/bbl)					
Sales price (2)	$ 66.31	$ 63.31	$ 50.65	$ 60.01	$ 59.83
Royalties	22.67	21.55	16.82	19.56	20.05
Production expenses	8.13	7.52	7.32	8.27	7.81
Netback	$ 35.51	$ 34.24	$ 26.51	$ 32.18	$ 31.97

North Sea production and netbacks by product type (1)					
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	36,879	37,669	27,045	31,701	33,292
Netbacks ($/bbl)					
Sales price (2)	$ 80.53	$ 79.30	$ 81.47	$ 88.05	$ 82.49
Royalties	0.17	0.18	0.13	0.16	0.16
Production expenses	25.15	21.35	44.45	30.05	29.73
Netback	$ 55.21	$ 57.77	$ 36.89	$ 57.84	$ 52.60
Natural gas					
Average daily production (before royalties) (MMcf/d)	15	9	8	9	10
Netbacks ($/Mcf)					
Sales price (2)	$ 4.30	$ 3.33	$ 4.52	$ 2.99	$ 3.83
Royalties	-	-	-	-	-
Production expenses	3.54	2.53	2.42	2.70	2.91
Netback	$ 0.76	$ 0.80	$ 2.10	$ 0.29	$ 0.92
Offshore West Africa production and netbacks by product type (1)					
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	29,942	29,842	33,554	27,706	30,264
Netbacks ($/bbl)					
Sales price (2)	$ 79.30	$ 79.21	$ 77.32	$ 80.39	$ 78.93
Royalties	2.69	4.29	6.52	7.01	5.54
Production expenses	13.49	18.33	13.66	13.86	14.64

Netback	$	63.12	$	56.59	$	57.14	$	59.52	$	58.75
Natural gas										
Average daily production (before royalties) (MMcf/d)		18		9		16		20		16
Netbacks ($/Mcf)										
Sales price (2)	$	5.56	$	5.14	$	7.36	$	7.59	$	6.63
Royalties		0.19		0.26		0.85		0.69		0.53
Production expenses		1.63		1.64		1.69		2.00		1.76
Netback	$	3.74	$	3.24	$	4.82	$	4.90	$	4.34

(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) Regulatory approval to expand the Brintnell OSR006 Oil Sands Project resulted in no royalties incurred for the quarter ended June 30, 2010.

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SELECTED FINANCIAL INFORMATION

The following table is a summary of the consolidated financial statements of the Company.

($ millions, except per common share information)	Year Ended Dec 31 2010	2009
Revenues, before royalties	$ 14,322	$ 11,078
Net earnings	$ 1,697	$ 1,580
Per common share - basic and diluted (1)	$ 1.56	$ 1.46
Adjusted net earnings from operations (2)	$ 2,570	$ 2,689
Per common share - basic and diluted (1)	$ 2.36	$ 2.48
Cash flow from operations (2)	$ 6,321	$ 6,090
Per common share - basic and diluted (1)	$ 5.81	$ 5.62
Total assets	$ 42,669	$ 41,024
Total long-term liabilities	$ 18,528	$ 19,193

(1) Per common share amounts have been restated to reflect a two-for-one common share split in May 2010.

(2) These non-GAAP measures are reconciled to net earnings as determined in accordance with Canadian GAAP in the "Financial Highlights" section of the Company's MD&A which is incorporated by reference into this document.

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 April 2001.

The following table 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 and is restated for the two-for-one subdivision of the common shares which occurred in May 2010.

	2010	2009	2008
Cash dividends declared per common share	$ 0.30	$ 0.21	$ 0.20

In March 2011, the Board of Directors resolved to increase the cash dividend on common shares for the eleventh year in a row and approved a 20% increase in the quarterly dividend from $0.075 per common share in 2010 to $0.09 per common share, effective with the April 1, 2011 payment.

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DESCRIPTION OF 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

The following information relating to the Company's credit ratings is provided as it relates to the Company's financing costs, liquidity and operations. Specifically, credit ratings affect the Company's ability to obtain short-term and long-term financing and the cost of such financing. A reduction in the current rating on the Company's debt by its rating agencies, particularly a downgrade below investment grade ratings, or a negative change in the Company's ratings outlook could adversely affect the Company's cost of financing and its access to sources of liquidity and capital. In addition, changes in credit ratings may affect the Company's ability to, and the associated costs of, entering into ordinary course derivative or hedging transactions and entering into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

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.

Canadian Natural’s senior unsecured debt securities are rated “Baa1” with a stable outlook by Moody’s Investor’s Service, Inc. (“Moody’s”), “BBB” by Standard & Poor’s Corporation (“S&P”) and “BBB (high)” with a stable trend by DBRS Limit (“DBRS”). S&P assigns a rating outlook to Canadian Natural and not to individual debt instruments. S&P has assigned a positive outlook to Canadian Natural. Credit ratings are intended to provide investors with an independent measure of credit quality of any issue of securities.

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. A rating of Baa1 by Moody’s is within the fourth highest of nine categories and is assigned to debt securities which are considered medium-grade obligations, i.e., they are subject to moderate credit risk. Such securities may possess certain speculative characteristics. 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 CCC 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 term. In determining a rating outlook, consideration is given to any changes in the economic and/or fundamental business conditions.

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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. The capacity for the payment of financial obligations is considered acceptable, though may be vulnerable to future events. 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.

2010 Monthly Historical Trading on TSX

Month		High	Low	Close	Volume Traded
January	$	77.40	67.62	68.25	24,763,430
February	$	73.70	67.66	70.88	25,082,609
March	$	75.75	71.50	75.17	30,452,299
April	$	80.16	75.52	78.23	30,858,117
May (1)	$	79.61	33.09	37.25	55,234,158
June	$	38.87	34.93	35.33	57,037,241
July	$	37.35	34.00	35.40	42,187,482
August	$	37.00	31.97	34.30	62,921,845
September	$	36.13	32.90	35.59	58,733,695
October	$	38.07	35.80	37.13	51,723,578
November	$	40.73	37.01	39.49	44,890,831
December	$	45.00	39.95	44.35	41,905,323

(1) Shares began trading on a post two-for-one trading basis on May 19, 2010.

In the first quarter 2010, the Company announced a Normal Course Issuer Bid to purchase up to 2.5% of its issued and outstanding common shares or 27,163,940 common shares on a post split basis, through the facilities of TSX and the NYSE during the twelve month period commencing April 6, 2010 and ending April 5, 2011. Under this program, during 2010 the Company purchased a total of 2,000,000 common shares for cancellation at an average purchase price of $33.77 per common share for a total cost of $68 million.

At the Annual and Special Meeting of Shareholders held on May 6, 2010, 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 shares occurred on May 21, 2010 on TSX and May 28, 2010 on the NYSE.

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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. Further detail on the Directors and Named Executive Officers are found in the Company's Information Circular dated March 16, 2011 incorporated by reference.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Catherine M. Best, FCA, ICD.D Calgary, Alberta Canada	Director (1)(2) (age 57)	Corporate director. Until May 2009, Interim Chief Financial Officer of Alberta Health Services which was formed in 2008 when the Alberta government consolidated all of the health regions of the province under one board. Prior thereto, Executive Vice-President, Risk Management and Chief Financial Officer of the Calgary Health Region (fully integrated publicly funded health care system) from 2000 to 2008. She has served continuously as a director of the Company since November 2003 and is currently serving on the board of directors of Enbridge Income Fund Holdings and Superior Plus Corporation. She is also a member of the Board of the Alberta Children's Hospital Foundation and serves as a volunteer member of the Audit Committee of the Calgary Exhibition and Stampede and of the Audit Committee of the University of Calgary.
N. Murray Edwards Calgary/Banff, Alberta Canada	Vice-Chairman and Director (5) (age 51)	President, Edco Financial Holdings Ltd. (private management and consulting company). He has served continuously as a director of the Company since September 1988. Currently is Chairman and serving on the board of directors of Ensign Energy Services Inc., and Magellan Aerospace Corporation.
Timothy W. Faithfull Oxford, England	Director (1)(3) (age 66)	Independent businessman and corporate director. From 1999 until July 2003 when he retired, he was President and Chief Executive Officer of Shell Canada Limited. He has served continuously as a director of the Company since November 2010. He is a Trustee of the Starehe Endowment Fund in the UK and a Council Member of the Canada – UK Colloquia and is currently serving on the board of directors of TransAlta Corporation, Canadian Pacific Railway, AMEC plc and Shell Pension Trust Limited.
Honourable Gary A. Filmon, P.C., O.C., O.M. Winnipeg, Manitoba Canada	Director (1)(4) (age 68)	Corporate director and a consultant with The Exchange Group (business consulting firm) since 2000. He has served continuously as a director of the Company since February 2006 and is currently serving on the board of directors of MTS Allstream Inc., Arctic Glacier Income Trust, Exchange Income Corporation, Wellington West

		Capital Inc. and FWS Construction Inc.
Christopher L. Fong Calgary, Alberta Canada	Director (3)(5) (age 61)	Corporate director. Until his retirement in May 2009 he was Global Head, Corporate Banking, Energy with RBC Capital Markets, a position he was appointed to in 2008. Prior thereto Managing Director, Corporate Banking, Energy with RBC Capital Markets from 1999 to February 2008. He has served continuously as a director of the Company since November 2010. He was appointed Advisor to the Alberta's Department of Energy's Competitive Review process in 2009, Governor and past Chair of EducationMatters, Chair of UNICEF Canada and is currently serving on the board of directors of Anderson Energy Ltd. and Westfire Energy Ltd. and sits on the Petroleum Advisory Committee of the Alberta Securities Commission and is a member of the Alberta Government's Oil and Gas Economics Advisory Council.

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Name	Position Presently Held	Principal Occupation During Past 5 Years
Ambassador Gordon D. Giffin Atlanta, Georgia USA	Director (1)(4) (age 61)	Senior Partner, McKenna Long & Aldridge LLP (law firm) since May 2001. He has served continuously as a director of the Company since May 2002. Currently serving on the board of directors of Canadian National Railway Company, Canadian Imperial Bank of Commerce, Just Energy Corp., and Transalta Corporation.
Wilfred A. Gobert Calgary, Alberta Canada	Director(2)(4) (age 63)	Independent businessman. Until his retirement in 2006, he was Vice-Chair of Peters and Co. Limited a position he held since 2002 and was a member of its Board of Directors and its Executive Committee. He has served continuously as a director since November 2010. He is currently serving on the board of directors of Gluskin Sheff & Associates, Trilogy Energy Corp. and Manitok Energy Inc.
Steve W. Laut Calgary, Alberta Canada	President and Director (age 53)	Officer of the Company. He has served continuously as a director of the Company since August 2006.
Keith A.J. MacPhail Calgary, Alberta Canada	Director (3)(5) (age 54)	Chairman and Chief Executive Officer, Bonavista Energy Corporation since November 1997 and Chairman, NuVista Energy Ltd. since July 2003. He has served continuously as a director of the Company since October 1993. He is currently serving on the board of directors of Bonavista Energy Corporation and NuVista Energy Ltd.
Allan P. Markin, O.C., A.O.E Calgary, Alberta Canada	Chairman and Director (3) (age 65)	Chairman of the Company. He has served continuously as a director of the Company since January 1989.
Honourable Frank J. McKenna, P.C., O.C., O.N.B., Q.C. Cap Pelé, New Brunswick Canada	Director (2)(4) (age 63)	Deputy Chair, TD Bank Financial Group (financial services). Prior thereto, 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.
James S. Palmer, C.M., A.O.E., Q.C. Calgary, Alberta Canada	Director (2)(5) (age 82)	Chairman and a Partner of Burnet, Duckworth & Palmer LLP (law firm). He has served continuously as a director of the Company since May 1997. Currently serving on the board of directors of Magellan Aerospace

		Corporation.
Dr. Eldon R. Smith, O.C., M.D. Calgary, Alberta Canada	Director (2)(3) (age 71)	President of Eldon R. Smith & Associates Ltd., (a private health care consulting company) since 2001, and is Emeritus Professor of Medicine and Former Dean, Faculty of Medicine, University of Calgary. He has served continuously as a director of the Company since May 1997. Currently serving on the board of directors of Intellipharmaceutics International Inc., Resverlogix Corp. and Aston Hill Financial.

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Name	Position Presently Held	Principal Occupation During Past 5 Years
David A. Tuer Calgary, Alberta Canada	Director (1)(5) (age 61)	Vice-Chairman and Chief Executive Officer of Teine Energy Ltd. (private oil and gas exploration company) and served as Vice-Chairman and Chief Executive Officer of Marble Point Energy Ltd the predecessor to Teine Energy Ltd also a private oil and gas exploration company from 2008 to 2010. Prior thereto he was Chairman, Calgary Health Region from 2001 to 2008 and Executive Vice-Chairman BA Energy Inc. from 2005 to 2008 when it was acquired by its parent company Value Creations Inc. through a Plan of Arrangement and which until recently was engaged in the development, building and operations of a merchant heavy oil upgrader in Northern Alberta for the purpose of upgrading bitumen and heavy oil feedstock into high-quality crude oils; and President, CEO and a director of Hawker Resources Inc. from January 2003 to March 2005. He has served continuously as a director of the Company since May 2002. Currently serving on the board of directors of Daylight Energy Limited, Xtreme Coil Drilling Corp. and Altalink Management LLP., a private limited partnership.
Jeffrey J. Bergeson Calgary, Alberta Canada	Vice-President, Exploitation West (age 54)	Officer of the Company since May 2007; prior thereto Exploitation Manager of the Company.
Corey B. Bieber Calgary, Alberta Canada	Vice-President, Finance and Investor Relations (age 47)	Officer of the Company.
Mary-Jo E. Case Calgary, Alberta Canada	Vice-President, Land (age 52)	Officer of the Company.
William R. Clapperton Calgary, Alberta Canada	Vice-President, Regulatory, Stakeholder and Environmental Affairs (age 48)	Officer of the Company.
James F. Corson Calgary, Alberta Canada	Vice-President, Human Resources, Horizon (age 60)	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.
Réal M. Cusson	Senior Vice-President,	Officer of the Company.

Calgary, Alberta Canada	Marketing (age 60)	
Randall S. Davis Calgary, Alberta Canada	Vice-President, Finance & Accounting (age 44)	Officer of the Company.
Réal J. H. Doucet Calgary, Alberta Canada	Senior Vice-President, Horizon Projects (age 58)	Officer of the Company.
Allan E. Frankiw Calgary, Alberta Canada	Vice-President, Production, Central (age 54)	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 Production Manager, Edson of the Company from November 2006 to March 2007.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Tim J. Hamilton Calgary, Alberta Canada	Vice-President, Developments (age 55)	Officer of the Company since February 2010; prior thereto Manager Production, Southern Alberta from 2000 to 2006, Manager Production, Southern Alberta, S.E. Saskatchewan and Manitoba 2006 to 2007, Manager Production, British Columbia South 2007 to September 2009 and most recently Manager Production, British Columbia from September 2009 to February 2010.
Peter J. Janson Calgary, Alberta Canada	Senior Vice-President, Horizon Operations (age 53)	Officer of the Company.
Terry J. Jocksch Calgary, Alberta Canada	Senior Vice-President, Thermal and International (age 43)	Officer of the Company since June 2009; prior thereto Exploitation Manager of the Company to April 2004, Vice-President Exploitation West April 2004 to May 2007, and most recently Managing Director, International May 2007 to June 2009.
Philip A. Keele Calgary, Alberta Canada	Vice-President, Mining, Horizon Oil Sands Project (age 51)	Officer of the Company.
Allen M. Knight Calgary, Alberta Canada	Senior Vice-President, International & Corporate Development (age 61)	Officer of the Company.
Cameron S. Kramer Calgary, Alberta Canada	Senior Vice-President, North America Operations (age 43)	Officer of the Company.
Ronald K. Laing Calgary, Alberta Canada	Vice-President, Commercial Operations (age 41)	Officer of the Company since March 2009; prior thereto Manager, Commercial Operations of the Company from April 2004 to March 2009.
John G. Langille Calgary, Alberta Canada	Vice-Chairman (age 65)	Officer of the Company.
Reno G. Laseur Fort McMurray, Alberta Canada	Vice-President, Upgrading (age 55)	Officer of the Company since August 2008; prior thereto Operations Manager, Upgrading of the Company November 2002 to October 2007, and most recently Operations Director, Upgrading of the Company from

		October 2007 to August 2008.
Bruce E. McGrath Calgary, Alberta Canada	Corporate Secretary (age 61)	Officer of the Company.
Tim S. McKay Calgary, Alberta Canada	Chief Operating Officer (age 49)	Officer of the Company.
Paul M. Mendes Calgary, Alberta Canada	Vice-President, Legal and General Counsel (age 45)	Officer of the Company since February 2010; prior thereto Manager, Legal Services, Horizon January 2005 to January 2007 and most recently Director, Legal Services, Horizon from January 2007 to February 2010.

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Name	Position Presently Held	Principal Occupation During Past 5 Years
Leon Miura Calgary, Alberta Canada	Vice-President, Horizon Downstream Projects (age 56)	Officer of the Company.
S. John Parr Calgary, Alberta Canada	Vice-President, Thermal Production (age 49)	Officer of the Company.
David A. Payne Calgary, Alberta Canada	Vice-President, Exploitation, Central (age 49)	Officer of the Company.
William R. Peterson Calgary, Alberta Canada	Vice-President, Production, West (age 44)	Officer of the Company.
Douglas A. Proll Calgary, Alberta Canada	Chief Financial Officer and Senior Vice-President, Finance (age 60)	Officer of the Company.
Timothy G. Reed Calgary, Alberta Canada	Vice-President, Human Resources (age 54)	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.
Joy P. Romero Calgary, Alberta Canada	Vice President, Technology Development (age 54)	Officer of the Company since March 2008; prior thereto Director, Bitumen Production Process of the Company from September 2002 to March 2008.
Sheldon L. Schroeder Fort McMurray, Alberta Canada	Vice-President, Horizon Upstream Projects (age 43)	Officer of the Company.
Kendall W. Stagg Calgary, Alberta Canada	Vice-President, Exploration, West (age 49)	Officer of the Company.
Scott G. Stauth Calgary, Alberta Canada	Vice-President, Field Operations (age 53)	Officer of the Company since November 2006; prior thereto Manager, Eastern Field Operations of the Company from April 2003 to November 2006.
Lyle G. Stevens Calgary, Alberta Canada	Senior Vice-President, Exploitation (age 56)	Officer of the Company.

Stephen C. Suche Calgary, Alberta Canada	Vice-President, Information and Corporate Services (age 51)	Officer of the Company since July 2006; prior thereto Manager Information and Corporate Services of the Company from January 2000 to July 2006.
Domenic Torriero Calgary, Alberta Canada	Vice-President, Exploration, Central (age 46)	Officer of the Company since November 2006; prior thereto Exploration Manager of the Company from March 2004 to November 2006.
Grant M. Williams Calgary, Alberta Canada	Vice-President, Thermal Exploration (age 53)	Officer of the Company since March 2007; prior thereto Manager, Exploration Heavy Oil of the Company from October 2003 to April 2007.

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Name	Position Presently Held	Principal Occupation During Past 5 Years
Jeffrey W. Wilson Calgary, Alberta Canada	Senior Vice-President, Exploration (age 58)	Officer of the Company.
Daryl G. Youck Calgary, Alberta Canada	Vice-President, Thermal Exploitation (age 42)	Officer of the Company since February 2008; prior thereto Manager, Exploitation of the Company from July 2002 to February 2008.
Lynn M. Zeidler Calgary, Alberta Canada	Vice-President, Horizon Technical, Business and Common Services (age 54)	Officer of the Company.

(1) Member of the Audit Committee

(2) Member of the Compensation Committee

(3) Member of the Health, Safety, and Environmental Committee

(4) Member of the Nominating and Corporate Governance Committee

(5) Member of the Reserves Committee

All directors stand for election at each Annual General Meeting of Canadian Natural shareholders. All of the current directors except for Messrs. T. W. Faithfull, C. L. Fong and W. A. Gobert who were appointed to the Board in November 2010, were elected to the Board at the last Annual and Special Meeting of Shareholders held on May 6, 2010.

As at December 31, 2010, the directors and officers of the Company, as a group, beneficially owned or controlled or directed, directly or indirectly, in the aggregate, approximately 4.2% of the total outstanding common shares (approximately 5.9% after the exercise of options held by them pursuant to the Company's stock option plan).

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. 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).

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

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 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.

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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 is reasonably expected to materially affect the Company.

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.

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

The Company's auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have prepared an independent auditors' report dated March 1, 2011 in respect of the Company's consolidated financial statements as at December 31, 2010 and December 31, 2009 with accompanying notes for each of the years in the three year period ended December 31, 2010 and the Company's internal control over financial reporting as at December 31, 2010. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Company within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and the rules of the SEC.

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, Sproule International Limited 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.

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, T.W. Faithful, G. D. Giffin and D. A. Tuer each of whom is independent and financially literate as those terms are defined under Canadian securities regulations, National Instrument 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.

Mr. T. W. Faithfull holds a Master of Arts degree in Economics and is an alumnus of the London Business School. As Chief Executive Officer of Shell Canada Limited and in his other capacities during his 36 years with the Royal Dutch/Shell group of companies, together with his experience as an audit committee member of other publicly traded companies, he has acquired significant financial experience and exposure to complex accounting and financial issues and an understanding of audit committee functions.

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.

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Ambassador G. D. Giffin's education and experience relevant to the performance of his responsibilities as an audit committee member is derived from a law practice of over thirty years 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.

Auditor Service Fees

The Audit Committee of the Board of Directors in 2010 approved specified audit and non-audit services to be performed by PricewaterhouseCoopers LLP ("PwC"). The services provided include: (i) the annual audit of the Corporation's consolidated financial statements and internal controls over financial reporting, reviews of the Corporation's quarterly unaudited consolidated financial statements, audits of certain of the Corporation's subsidiary companies' annual financial statements, assistance related to the Corporation's conversion to International Financial Reporting Standards, as well as other audit services provided in connection with statutory and regulatory filings; (ii) audit related services including debt covenant compliance and Crown Royalty Statements; (iii) tax services related to expatriate personal tax and compliance, other corporate tax return matters, and participation in a global taxation study; and (iv) non-audit services related to the design of a crown royalty compliance program as well as accessing resource materials through PwC's accounting literature library.

Fees accrued to PwC are shown in the table below.

Auditor service		2010		2009
Audit fees	$	3,001,500	$	2,710,100
Audit related fees		169,000		154,300
Tax fees		149,000		131,650
All other fees		54,100		9,500
	$	3,373,600	$	3,005,550

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

ADDITIONAL INFORMATION

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

Additional information including Directors' and Executive Officers' remuneration and indebtedness, Director nominees standing for re-election, 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 General Meeting and Information Circular dated March 16, 2011 in connection with the Annual and General Meeting of Shareholders of Canadian Natural to be held on May 5, 2011 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, 2010 found on pages 23 to 55, 56 to 85 and 86 to 93 respectively, of the 2010 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

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SCHEDULE "A"

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 and reviewed the Corporation's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

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 and review.

We carried out our evaluation and review in accordance with the standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated and reviewed by us for the year ended December 31, 2010 and identifies the respective portions thereof that we have evaluated and reviewed and reported on to the Corporation's management and board of directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation/Review Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate) ($millions)			
			Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	Sproule evaluated the P&NG Reserves as reported February 14, 2011.	Canada and USA	$ 0	$ 40,531	$ 1,415	$ 41,946
Sproule International Limited	Sproule evaluated the P&NG Reserves as reported February 14, 2011.	United Kingdom and Offshore West Africa	$ 0	$ 11,307	$ 0	$ 11,307
GLJ Petroleum Consultants Ltd.	GLJ evaluated the oil sands mining properties	Canada	$ 0	$ 21,804	$ 0	$ 21,804

	as reported February 14, 2011.				
Totals		$ 0	$73,642	$ 1,415	$ 75,057

5. 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. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

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Executed as to our report(s) referred to above:

Sproule
Associates
Limited, Calgary,
Alberta, Canada,
March 1, 2011

Original Signed
By:

SIGNED
"Harry J.
Helwerda"
Harry J.
Helwerda,
P.Eng., FEC
Executive
Vice-President

Original Signed
By:

SIGNED
"Doug
W.C. Ho"
Doug W.C. Ho,
P.Eng.
Vice-President,
Unconventional

Original Signed
By:

SIGNED
"R. Keith
MacLeod"
R. Keith
MacLeod, P.Eng.
President

Sproule
International
Limited, Calgary,
Alberta, Canada,

March 1, 2011

Original Signed
By:

SIGNED
“Harry J.
Helwerda”
Harry J.
Helwerda,
P.Eng., FEC
Executive
Vice-President

Original Signed
By:

SIGNED
“Greg D.
Robinson”
Greg D.
Robinson, P.Eng.
Vice-President,
International

Original Signed
By:

SIGNED
“R. Keith
MacLeod”
R. Keith
MacLeod, P.Eng.
President

GLJ Petroleum
Consultants Ltd.,
Calgary, Alberta,
Canada, March
1, 2011

Original Signed
By:

SIGNED
“James H.
Willmon”

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

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SCHEDULE "B"

FORM 51-101F3

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 oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated and reviewed 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 of 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 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 oil and 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 Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

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Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Original Signed By:

SIGNED "STEVE W. LAUT"
Steve W. Laut
President

Original Signed By:

SIGNED "DOUGLAS A. PROLL"
Douglas A. Proll
Chief Financial Officer and Senior Vice
President, Finance

Original Signed By:

SIGNED "DAVID A. TUER"
David A. Tuer
Independent Director and Chair of the
Reserve Committee

Original Signed By:

SIGNED "JAMES S. PALMER"
James S. Palmer
Independent Director and Member of the
Reserve Committee

Dated this 1st day of March, 2011

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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. Although the Audit Committee has the powers and responsibilities set forth in this Charter, the role of the Audit Committee is oversight. The Audit Committee's primary duties and responsibilities are to:

1. ensure that the Corporation's management implemented an effective system of internal controls over financial reporting;

2. monitor and oversee 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, qualifications and performance of the Corporation's independent auditors and oversee the audit of the Corporation's financial statements;

5. monitor the performance of the internal audit 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.

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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 implemented and is maintaining an effective system of internal controls over financial reporting;

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 review and discuss with management and the independent auditors prior to the annual audit the independent auditor's annual audit plan, including scope, staffing, locations and reliance upon management and internal audit department and oversee the audit of the Corporation's financial statements;

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.

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 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 (including financial 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 extent to which recommendations made by the internal audit staff or by the independent auditors have been implemented.

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

a. to review and discuss with management, the internal audit group and the independent auditors, 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 and discuss with management, the internal audit group and the independent auditors, 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 management's report on 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 Committt

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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:

the Company's consolidated financial statements as at and for the year ended December 31, 2010; and

the effectiveness of the Company's internal control over financial reporting as at December 31, 2010.

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 entirely of independent 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.

(signed) "Steve W. Laut"
Steve W. Laut
President

(signed) "Douglas A. Proll"
Douglas A. Proll, CA
Chief Financial Officer &
Senior Vice-President,
Finance

(signed) "Randall S. Davis"
Randall S. Davis, CA
Vice-President, Finance &
Accounting

Calgary, Alberta, Canada
March 1, 2011

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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 Rules 13(a)–15(f) and 15d–15(f) under the United States Securities Exchange Act of 1934, as amended.

Management, including the Company’s President 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 has concluded that the Company’s internal control over financial reporting is effective as at December 31, 2010. 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.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has provided an opinion on the Company’s internal control over financial reporting as at December 31, 2010, as stated in their Auditor’s Report.

(signed) “Steve W. Laut” Steve W. Laut President	(signed) ”Douglas A. Proll” Douglas A. Proll, CA Chief Financial Officer & Senior Vice-President, Finance

Calgary, Alberta, Canada
March 1, 2011

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Independent Auditor's Report

To the Shareholders
of Canadian Natural Resources Limited

We have completed integrated audits of Canadian Natural Resources Limited's 2010, 2009 and 2008 consolidated financial statements and of its internal control over financial reporting as at December 31, 2010. Our opinions, based on our audits, are presented below.

Report on the consolidated financial statements

We have audited the accompanying consolidated financial statements of Canadian Natural Resources Limited (the "Company"), which comprise the consolidated balance sheets as at December 31, 2010 and December 31, 2009, and the related consolidated statements of earnings, changes in shareholders' equity, comprehensive income and cash flows for each of the three years in the period ended December 31, 2010 and the related notes.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the consolidated financial statements.

"PricewaterhouseCoopers" refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership, or, as the context requires, the PricewaterhouseCoopers global network or other member firms of the network, each of which is a separate legal entity.

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Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Canadian Natural Resources Limited as at December 31, 2010 and December 31, 2009 and the results of its operations and cash flows for each of the three years in the period ended December 31, 2010 in accordance with Canadian generally accepted accounting principles.

Report on internal control over financial reporting

We have also audited Canadian Natural Resources Limited's internal control over financial reporting as at December 31, 2010, based on criteria established in Internal Control - Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Management's responsibility for internal control over financial reporting

Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report.

Auditor's responsibility

Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on the Company's internal control over financial reporting.

Definition of internal control over financial reporting

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 Canadian 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 Canadian 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.

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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.

Opinion

In our opinion, Canadian Natural Resources Limited maintained, in all material respects, effective internal control over financial reporting as at December 31, 2010 based on criteria established in Internal Control - Integrated Framework, issued by COSO.

(signed) “PricewaterhouseCoopers LLP”
Chartered Accountants
Calgary, Alberta
Canada
March 1, 2011

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Consolidated Balance Sheets

As at December 31 (millions of Canadian dollars)		2010		2009
ASSETS				
Current assets				
Cash and cash equivalents	$	22	$	13
Accounts receivable		1,481		1,148
Inventory, prepaids and other		610		584
Future income tax (note 7)		59		146
		2,172		1,891
Property, plant and equipment (note 4)		40,472		39,115
Other long-term assets (note 3)		25		18
	$	42,669	$	41,024
LIABILITIES				
Current liabilities				
Accounts payable	$	274	$	240
Accrued liabilities		2,163		1,522
Current portion of other long-term liabilities (note 6)		719		643
		3,156		2,405
Long-term debt (note 5)		8,499		9,658
Other long-term liabilities (note 6)		2,130		1,848
Future income tax (note 7)		7,899		7,687
		21,684		21,598
SHAREHOLDERS' EQUITY				
Share capital (note 8)		3,147		2,834
Retained earnings		18,005		16,696
Accumulated other comprehensive loss (note 9)		(167)		(104)
		20,985		19,426
	$	42,669	$	41,024

Commitments and contingencies (note 13)

Approved by the Board of Directors:

Catherine M. Best
Chair of the Audit Committee and
Director

N. Murray Edwards
Vice-Chairman of the Board of Directors and
Director

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Consolidated Statements of Earnings

For the years ended December 31 (millions of Canadian dollars, except per common share amounts)	2010	2009	2008
Revenue	$ 14,322	$ 11,078	$ 16,173
Less: royalties	(1,421)	(936)	(2,017)
Revenue, net of royalties	12,901	10,142	14,156
Expenses			
Production	3,447	2,987	2,451
Transportation and blending	1,783	1,218	1,936
Depletion, depreciation and amortization	4,036	2,819	2,683
Asset retirement obligation accretion (note 6)	107	90	71
Administration	210	181	180
Stock-based compensation expense (recovery) (note 6)	294	355	(52)
Interest, net	449	410	128
Risk management activities (note 12)	(121)	738	(1,230)
Foreign exchange (gain) loss	(182)	(631)	718
	10,023	8,167	6,885
Earnings before taxes	2,878	1,975	7,271
Taxes other than income tax (note 7)	119	106	178
Current income tax expense (note 7)	698	388	501
Future income tax expense (recovery) (note 7)	364	(99)	1,607
Net earnings	$ 1,697	$ 1,580	$ 4,985
Net earnings per common share (note 11)			
Basic and diluted	$ 1.56	$ 1.46	$ 4.61

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Consolidated Statements of Shareholders' Equity

For the years ended December 31 (millions of Canadian dollars)	2010	2009	2008
Share capital (note 8)			
Balance – beginning of year	$ 2,834	$ 2,768	$ 2,674
Issued upon exercise of stock options	170	24	18
Previously recognized liability on stock options exercised for common shares	149	42	76
Purchase of common shares under Normal Course Issuer Bid	(6)	–	–
Balance – end of year	3,147	2,834	2,768
Retained earnings			
Balance – beginning of year	16,696	15,344	10,575
Net earnings	1,697	1,580	4,985
Purchase of common shares under Normal Course Issuer Bid	(62)	–	–
Dividends on common shares (note 8)	(326)	(228)	(216)
Balance – end of year	18,005	16,696	15,344
Accumulated other comprehensive (loss) income (note 9)			
Balance – beginning of year	(104)	262	72
Other comprehensive (loss) income, net of taxes	(63)	(366)	190
Balance – end of year	(167)	(104)	262
Shareholders' equity	$ 20,985	$ 19,426	$ 18,374

Consolidated Statements of Comprehensive Income

For the years ended December 31 (millions of Canadian dollars)	2010	2009	2008
Net earnings	$ 1,697	$ 1,580	$ 4,985
Net change in derivative financial instruments designated as cash flow hedges			
Unrealized (loss) income during the year, net of taxes of $11 million (2009 – $5 million, 2008 – $1 million)	(24)	(33)	30
Reclassification to net earnings, net of taxes of $1 million (2009 – $1 million, 2008 – $6 million)	(4)	(10)	(12)
	(28)	(43)	18
Foreign currency translation adjustment			
Translation of net investment	(35)	(323)	172
Other comprehensive (loss) income, net of taxes	(63)	(366)	190
Comprehensive income	$ 1,634	$ 1,214	$ 5,175

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Consolidated Statements of Cash Flows

For the years ended December 31 (millions of Canadian dollars)	2010	2009	2008
Operating activities			
Net earnings	$ 1,697	$ 1,580	$ 4,985
Non-cash items			
Depletion, depreciation and amortization	4,036	2,819	2,683
Asset retirement obligation accretion	107	90	71
Stock-based compensation expense (recovery)	294	355	(52)
Unrealized risk management (gain) loss	(25)	1,991	(3,090)
Unrealized foreign exchange (gain) loss	(180)	(661)	832
Deferred petroleum revenue tax expense (recovery)	28	15	(67)
Future income tax expense (recovery)	364	(99)	1,607
Other	(7)	5	25
Abandonment expenditures	(179)	(48)	(38)
Net change in non-cash working capital (note 14)	149	(235)	(189)
	6,284	5,812	6,767
Financing activities			
Repayment of bank credit facilities, net	(472)	(2,021)	(623)
Repayment of medium-term notes	(400)	–	–
Repayment of senior unsecured notes	–	(34)	(31)
Issue of US dollar debt securities	–	–	1,215
Issue of common shares on exercise of stock options	170	24	18
Purchase of common shares under Normal Course Issuer Bid	(68)	–	–
Dividends on common shares	(302)	(225)	(208)
Net change in non-cash working capital (note 14)	(5)	(12)	46
	(1,077)	(2,268)	417
Investing activities			
Expenditures on property, plant and equipment	(5,335)	(2,985)	(7,433)
Proceeds on sale of property, plant and equipment	8	36	20
Net expenditures on property, plant and equipment	(5,327)	(2,949)	(7,413)
Net change in non-cash working capital (note 14)	129	(609)	235
	(5,198)	(3,558)	(7,178)
Increase (decrease) in cash and cash equivalents	9	(14)	6
Cash and cash equivalents – beginning of year	13	27	21
Cash and cash equivalents – end of year	$ 22	$ 13	$ 27

Supplemental disclosure of cash flow information (note 14)

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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 Exploration and Production operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Côte d'Ivoire and Gabon in Offshore West Africa.

The Horizon Oil Sands Mining and Upgrading segment ("Horizon") produces synthetic crude oil through bitumen mining and upgrading operations.

Also within Western Canada, the Company maintains certain midstream activities that include 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 17.

Significant 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 in impairment calculations are based on estimates of crude oil and natural gas reserves. The estimation of reserves involves the exercise of judgement. Forecasts are based on engineering data, estimated 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, and may be affected by changes in commodity prices. As a result, the impact of differences between actual and estimated crude oil and natural gas reserves amounts on the consolidated financial statements of future periods may 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 future inflation rates. The impact of differences between actual and estimated costs, timing and inflation on the consolidated financial statements of future periods may be material.

The calculation of income taxes requires judgement in applying tax laws and regulations, estimating the timing of temporary difference reversals, and estimating the realizability of future tax assets. These estimates impact current and future income tax assets and liabilities, and current and future income tax expense (recovery).

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 may result in material changes to deferred amounts.

The estimation of fair value for derivative financial instruments requires the use of assumptions. In determining these assumptions, the Company has relied primarily on external, readily observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

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(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) INVENTORIES

Inventories are carried at the lower of cost and net realizable value. Cost consists of purchase costs, direct production costs, direct overhead and depletion, depreciation and amortization and is determined on a first-in, first-out basis. Inventories are primarily comprised of crude oil production held for sale.

(E) PROPERTY, PLANT AND EQUIPMENT

Exploration and Production

The Company follows the full cost method of accounting for its Exploration and Production properties and equipment as prescribed by Accounting Guideline 16 ("AcG 16") issued 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. Directly attributable administrative overhead incurred during the development of certain 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 a gain or loss except where such dispositions result in a change in the depletion rate of the specific cost centre of 20% or more.

Oil Sands Mining and Upgrading

Horizon is comprised of both mining and upgrading operations and accordingly, capitalized costs are accounted for separately from the Company's Canadian Exploration and Production costs. Capitalized mining activity costs include property acquisition, construction and development costs. Construction and development costs are capitalized separately to each Phase of Horizon. The construction and development of a particular Phase of Horizon is considered complete once the Phase is available for its intended use. Costs related to major maintenance turnaround activities are capitalized as incurred and amortized on a straight-line basis over the period to the next scheduled major maintenance turnaround. During 2009, Horizon Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs ceased and depletion, depreciation and amortization of these assets commenced.

Midstream and Other

The Company capitalizes all costs that expand the capacity or extend the useful life of the assets.

(F) OVERBURDEN REMOVAL COSTS

Overburden removal costs incurred during development of the Horizon mine are capitalized to property, plant and equipment. Overburden removal costs incurred during production of the Horizon mine are included in the cost of inventory, unless the overburden removal activity has resulted in a betterment of the mineral property, in which case the costs are capitalized to property, plant and equipment. Capitalized overburden removal costs are amortized over the life of the mining reserves that directly benefit from the overburden removal activity.

(G) CAPITALIZED INTEREST

The Company capitalizes construction period interest based on major qualifying costs incurred and the Company's cost of borrowing. Interest capitalization on a particular project ceases once this project is available for its intended use.

(H) LEASES

Leases that transfer substantially all of the benefits and risks of ownership to the Company are accounted for as capital leases and are recorded as property, plant and equipment with an offsetting liability. All other leases are accounted for as operating leases whereby lease costs are expensed as incurred. Contractual arrangements that meet the definition of a lease are accounted for as capital leases or operating leases as appropriate.

(I) DEPLETION, DEPRECIATION, AMORTIZATION AND IMPAIRMENT

Exploration and Production

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. Costs for major development projects, as identified by management, are not subject to depletion until the projects are available for their intended use. Unproved properties and major development projects are assessed periodically to determine whether impairment has occurred. When proved reserves are assigned or the value of an unproved property or major development project is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion. Processing and production facilities are depreciated on a straight-line basis over their estimated lives.

The Company reviews the carrying amount of its Exploration and Production 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 and depreciation expense 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 plus probable reserves and expected future prices and costs, discounted at a risk-free interest rate.

Oil Sands Mining and Upgrading

Mine-related costs and costs of the upgrader and related infrastructure located on the Horizon site are amortized on the unit-of-production method based on the estimated proved reserves of Horizon or productive capacity, respectively. Moveable mine-related equipment is depreciated on a straight-line basis over its estimated useful life.

The Company reviews the carrying amount of Horizon relative to its recoverable amount if circumstances or events indicate impairment may have occurred. The recoverable amount is calculated as the undiscounted cash flow from Horizon assets using proved plus probable reserves and expected future prices and costs. If the carrying amount exceeds the recoverable amount, an impairment loss is recognized in depletion equal to the amount by which the carrying amount of the assets exceeds fair value. Fair value is calculated as the discounted cash flow from Horizon using proved plus probable reserves and expected future prices and costs.

Midstream and Other

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. Other capital assets are amortized on a declining balance basis.

(J) ASSET RETIREMENT OBLIGATIONS

The Company provides for future asset retirement obligations on its resource properties, facilities, production platforms, gathering systems, and oil sands mining operations and tailings ponds 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.

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(K) 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 accumulated other comprehensive income (loss) 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 and foreign currency balances are included in the consolidated statements of earnings.

(L) REVENUE RECOGNITION AND COSTS OF GOODS SOLD

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.

Related costs of goods sold are comprised of production, transportation and blending, and depletion, depreciation and amortization expenses. These amounts have been separately presented in the consolidated statements of earnings.

(M) 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 oil and profit oil. Cost recovery oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the respective Government State Oil Companies (the "Governments"). Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Governments. The Governments' share of profit oil attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the terms of the PSCs.

(N) PETROLEUM REVENUE TAX

The Company accounts for the UK petroleum revenue tax ("PRT") over the life of the field. The total future liability or recovery of PRT is estimated using proved plus probable reserves and anticipated future 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.

(O) 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 or 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 arising from the Exploration and Production business in Canada is primarily generated through partnerships, with the related income taxes payable in subsequent periods. Accordingly, North America current and future income taxes have been provided on the basis of this corporate structure.

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(P) 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 a 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, after consideration of 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 capitalized during the construction period in the case of Horizon. 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.

(Q) FINANCIAL INSTRUMENTS

The Company classifies its financial instruments into one of the following categories: held-for-trading financial assets and financial liabilities; held-to-maturity investments; loans and receivables; available-for-sale financial assets; and other financial liabilities. All financial instruments are required to be measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

Held-for-trading financial instruments are subsequently measured at fair value with changes in fair value recognized in net earnings. Available-for-sale financial assets are subsequently measured at fair value with changes in fair value recognized in other comprehensive income, net of tax. All other categories of financial instruments are measured at amortized cost using the effective interest method.

Cash and cash equivalents are classified as held-for-trading and are measured at fair value. Accounts receivable are classified as loans and receivables. Accounts payable, accrued liabilities, certain other long-term liabilities, and long-term debt are classified as other financial liabilities. Although the Company does not intend to trade its derivative financial instruments, risk management assets and liabilities are classified as held-for-trading for accounting purposes.

Financial assets and liabilities are categorized using a three-level hierarchy that reflects the significance of the inputs used in making fair value measurements for these assets and liabilities. The fair values of financial assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair values of financial assets and liabilities in Level 2 are based on inputs other than Level 1 quoted prices that are observable for the asset or liability either directly (as prices) or indirectly (derived from prices). The fair values of Level 3 financial assets and liabilities are not based on observable market data. The disclosure of the fair value hierarchy excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability.

Transaction costs that are directly attributable to the acquisition or issue of a financial asset or liability and original issue discounts on long-term debt have been included in the carrying value of the related financial asset or liability and are amortized to consolidated net earnings over the life of the financial instrument using the effective interest method.

(R) RISK MANAGEMENT ACTIVITIES

The Company uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized on the consolidated balance sheet at estimated fair value at each balance sheet date. The estimated fair value of derivative financial instruments is determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates.

The Company documents all derivative financial instruments that are formally 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 periodically enters into commodity price contracts to manage anticipated sales of crude oil and natural gas production and purchases of natural gas in order to protect cash flow for capital expenditure programs. The effective portion of changes in the fair value of derivative commodity price contracts formally designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to risk management activities in consolidated net earnings in the same period or periods in which the commodity is sold. The ineffective portion of changes in the fair value of these designated contracts is immediately recognized in risk management activities in consolidated net earnings. All changes in the fair value of non-designated crude oil and natural gas commodity price contracts are recognized in risk management activities in consolidated net earnings.

The Company enters into interest rate swap contracts to manage its fixed to floating interest rate mix on certain of its 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. Changes in the fair value of interest rate swap contracts designated as fair value hedges and corresponding changes in the fair value of the hedged long-term debt are included in interest expense in consolidated net earnings. Changes in the fair value of non-designated interest rate swap contracts are included in risk management activities in consolidated net earnings.

Cross currency swap contracts are periodically used 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. Changes in the fair value of the foreign exchange component of cross currency swap contracts designated as cash flow hedges are included in foreign exchange in consolidated net earnings. The effective portion of changes in the fair value of the interest rate component of cross currency swap contracts designated as cash flow hedges is initially included in other comprehensive income and is reclassified to interest expense when realized, with the ineffective portion recognized in risk management activities in consolidated net earnings. Changes in the fair value of non-designated cross currency swap contracts are included in risk management activities in consolidated net earnings.

Realized gains or losses on the termination of financial instruments that have been designated as cash flow hedges are deferred under accumulated other comprehensive income on the consolidated balance sheets and amortized into consolidated net earnings in the period in which the underlying hedged item 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 consolidated net earnings. Realized gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in consolidated net earnings immediately.

Upon termination of an interest rate swap designated as a fair value hedge, the interest rate swap is de-recognized on the balance sheet and the related long-term debt hedged is no longer revalued for changes in fair value. The fair value adjustment on the long-term debt at the date of termination of the interest rate swap is amortized to interest expense over the remaining term of the debt.

Foreign currency forward contracts are periodically used to manage foreign currency cash management requirements.The foreign currency forward contracts involve the purchase or sale of an agreed upon amount of US dollars at a specified future date at forward exchange rates. Changes in the fair value of foreign currency forward contracts designated as cash flow hedges are initially recorded in other comprehensive income and are reclassified to foreign exchange loss (gain) when realized. Changes in the fair value of foreign currency forward contracts not designated as hedges are included in risk management activities in consolidated net earnings.

Embedded derivatives are derivatives that are included in a non-derivative host contract. Embedded derivatives are recorded at fair value separately from the host contract when their economic characteristics and risks are not clearly and closely related to the host contract.

(S) COMPREHENSIVE INCOME

Comprehensive income is comprised of the Company's net earnings and other comprehensive income. Other comprehensive income includes the effective portion of changes in the fair value of derivative financial instruments designated as cash flow hedges and foreign currency translation gains and losses on the net investment in self-sustaining foreign operations. Other comprehensive income is shown net of related income taxes.

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(T) 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 8 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 the calculation of 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.

(U) COMPARATIVE FIGURES

Certain prior year figures have been reclassified to conform to the presentation adopted in 2010. Common share, per common share, and stock option data has been restated to reflect the two-for-one share split in May 2010.

2. INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, the Canadian Institute of Chartered Accountants' Accounting Standards Board confirmed that Canadian publicly accountable entities will be required to adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board in place of Canadian GAAP effective January 1, 2011.

3. OTHER LONG-TERM ASSETS

	2010	2009
Other	$ 25	$ 18

4. PROPERTY, PLANT AND EQUIPMENT

	2010			2009		
	Cost	Accumulated depletion and depreciation	Net	Cost	Accumulated depletion and depreciation	Net
Exploration and Production						
North America	$ 43,014	$ 18,740	$ 24,274	$ 38,259	$ 16,425	$ 21,834
North Sea	3,757	2,232	1,525	3,879	2,067	1,812
Offshore West Africa	2,943	1,965	978	2,861	978	1,883
Other	45	14	31	42	14	28
Oil Sands Mining and Upgrading	13,957	556	13,401	13,481	186	13,295
Midstream	291	89	202	284	81	203
Head office	213	152	61	200	140	60
	$ 64,220	$ 23,748	$ 40,472	$ 59,006	$ 19,891	$ 39,115

During the year ended December 31, 2010, the Company capitalized directly attributable administrative costs of $43 million (2009 – $41 million, 2008 – $55 million) in the North Sea and Offshore West Africa, related to exploration and development and $33 million (2009 – $79 million, 2008 – $404 million) in North America, related to Oil Sands Mining and Upgrading.

During the year ended December 31, 2010, the Company capitalized $28 million (2009 – $106 million, 2008 – $481 million) in construction period interest costs related to Oil Sands Mining and Upgrading.

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

	2010	2009
Exploration and Production		
North America	$ 2,362	$ 2,102
North Sea	–	4
Offshore West Africa	–	666
Other	31	28
Oil Sands Mining and Upgrading	915	752
	$ 3,308	$ 3,552

The Company has used the following estimated benchmark future prices ("escalated pricing") in its full cost ceiling tests for Exploration and Production properties prepared in accordance with Canadian GAAP, as at December 31, 2010:

	2011	2012	2013	2014	2015	Average annual increase thereafter
Crude oil and NGLs						
North America						
WTI at Cushing (US$/bbl)	$ 88.40	$ 89.14	$ 88.77	$ 88.88	$ 90.22	1.5%
Western Canada Select (C$/bbl)	$ 80.04	$ 80.71	$ 78.48	$ 76.70	$ 77.86	1.5%
Edmonton Par (C$/bbl)	$ 93.08	$ 93.85	$ 93.43	$ 93.54	$ 94.95	1.5%
Edmonton C5+ (C$/bbl)	$ 95.32	$ 96.11	$ 95.68	$ 95.79	$ 97.24	1.5%
North Sea and Offshore West Africa						
North Sea Brent (US$/bbl)	$ 87.15	$ 87.87	$ 87.48	$ 87.58	$ 88.89	1.5%
Natural gas						
North America						
Henry Hub Louisiana (US$/MMBtu)	$ 4.44	$ 5.01	$ 5.32	$ 6.80	$ 6.90	1.5%
AECO (C$/MMBtu)	$ 4.04	$ 4.66	$ 4.99	$ 6.58	$ 6.69	1.5%
BC Westcoast Station 2 (C$/MMBtu)	$ 3.98	$ 4.60	$ 4.93	$ 6.52	$ 6.63	1.5%

At December 31, 2010, Offshore West Africa property, plant and equipment was reduced by a pre-tax ceiling test impairment charge of $726 million (2009 – $115 million). The impairment charge was included in depletion, depreciation and amortization expense.

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5. LONG-TERM DEBT

	2010	2009
Canadian dollar denominated debt		
Bank credit facilities		
Bankers' acceptances	$ 1,436	$ 1,897
Medium-term notes		
5.50% unsecured debentures due December 17, 2010	–	400
4.50% unsecured debentures due January 23, 2013	400	400
4.95% unsecured debentures due June 1, 2015	400	400
	2,236	3,097
US dollar denominated debt		
US dollar debt securities		
6.70% due July 15, 2011 (US$400 million)	398	419
5.45% due October 1, 2012 (US$350 million)	348	366
5.15% due February 1, 2013 (US$400 million)	398	419
4.90% due December 1, 2014 (US$350 million)	348	366
6.00% due August 15, 2016 (US$250 million)	249	262
5.70% due May 15, 2017 (US$1,100 million)	1,094	1,151
5.90% due February 1, 2018 (US$400 million)	398	419
7.20% due January 15, 2032 (US$400 million)	398	419
6.45% due June 30, 2033 (US$350 million)	348	366
5.85% due February 1, 2035 (US$350 million)	348	366
6.50% due February 15, 2037 (US$450 million)	447	471
6.25% due March 15, 2038 (US$1,100 million)	1,094	1,151
6.75% due February 1, 2039 (US$400 million)	398	419
Less – original issue discount (1)	(20)	(22)
	6,246	6,572
Fair value impact of interest rate swaps on US dollar debt securities (2)	61	38
	6,307	6,610
Long-term debt before transaction costs	8,543	9,707
Less: transaction costs (1) (3)	(44)	(49)
	$ 8,499	$ 9,658

(1) The Company has included unamortized original issue discounts and directly attributable transaction costs in the carrying value of the outstanding debt.

(2) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $61 million (2009 – $38 million) to reflect the fair value impact of hedge accounting.

(3) Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency and other professional fees.

Bank Credit Facilities

As at December 31, 2010, the Company had in place unsecured bank credit facilities of $3,953 million, comprised of:

a $200 million demand credit facility;

a revolving syndicated credit facility of $2,230 million maturing June 2012;

a revolving syndicated credit facility of $1,500 million maturing June 2012; and
a £15 million demand credit facility related to the Company’s North Sea operations.

The revolving syndicated credit 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. Borrowings under these facilities can be made by way of Canadian dollar and US dollar bankers’ acceptances, and LIBOR, US base rate and Canadian prime loans.

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During 2009, the Company repaid the remaining $2,350 million outstanding on the non-revolving syndicated credit facility related to the acquisition of Anadarko Canada Corporation and cancelled the facility.

During 2009, the Company renegotiated its demand credit facility, increasing it to $200 million.

The Company's weighted average interest rate on bank credit facilities outstanding as at December 31, 2010, was 1.5% (2009 – 0.8%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $283 million, including $205 million related to Horizon, were outstanding at December 31, 2010. Subsequent to December 31, 2010 the financial guarantee related to Horizon was reduced to $190 million.

Medium-Term Notes
During 2010, the Company repaid $400 million of medium-term notes bearing interest at 5.50%.

During 2009, the Company filed a base shelf prospectus that allows for the issue of up to $3,000 million of medium-term notes in Canada until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

US Dollar Debt Securities
During 2010, the Company unwound the interest rate swaps previously designated as a fair value hedge of US$350 million of 4.90% unsecured notes due December 2014. Accordingly, the Company ceased revaluing the related debt for subsequent changes in fair value from the date of unwind. The fair value adjustment of $55 million at the date of unwind is being amortized to interest expense over the remaining term of the debt.

During 2009, the Company filed a base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

Required Debt Repayments
Required debt repayments are as follows:

Year		Repayment
2011	$	398
2012	$	348
2013	$	798
2014	$	348
2015	$	400
Thereafter	$	4,774

No debt repayments are reflected in the above table for $1,436 million of revolving bank credit facilities due to the extendable nature of the facilities. Should the bank credit facilities not be extended by mutual agreement of the Company and the lenders, the amounts outstanding under these facilities would be due in 2012.

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6. OTHER LONG-TERM LIABILITIES

	2010	2009
Asset retirement obligations	$ 1,779	$ 1,610
Stock-based compensation	516	392
Risk management (note 12)	451	309
Other	103	180
	2,849	2,491
Less: current portion	719	643
	$ 2,130	$ 1,848

Asset Retirement Obligations

At December 31, 2010, the Company's total estimated undiscounted costs to settle its asset retirement obligations were approximately $7,232 million (2009 – $6,606 million; 2008 – $4,474 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 a weighted average credit-adjusted risk-free interest rate of 6.6% (2009 – 6.9%; 2008 – 6.7%). A reconciliation of the discounted asset retirement obligations is as follows:

	2010	2009	2008
Balance – beginning of year	$ 1,610	$1,064	$1,074
Liabilities incurred (1)	12	299	18
Liabilities acquired	22	–	3
Liabilities settled	(179)	(48)	(38)
Asset retirement obligation accretion	107	90	71
Revision of estimates	240	276	(156)
Foreign exchange	(33)	(71)	92
Balance – end of year	$ 1,779	$1,610	$1,064

(1) During 2009, the Company recognized additional asset retirement obligations related to Oil Sands Mining and Upgrading and Gabon, Offshore West Africa.

Stock-Based Compensation

The Company recognizes a liability for potential cash settlements under its Option Plan. The current portion represents the maximum amount of the liability payable within the next 12–month period if all vested options are surrendered for cash settlement.

	2010	2009	2008
Balance – beginning of year	$ 392	$ 171	$ 529
Stock-based compensation expense (recovery)	294	355	(52)
Cash payment for options surrendered	(45)	(94)	(207)
Transferred to common shares	(149)	(42)	(76)
Capitalized (recovery) to Oil Sands Mining and Upgrading	24	2	(23)
Balance – end of year	516	392	171
Less: current portion	472	365	159
	$ 44	$ 27	$ 12

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7. TAXES

Taxes Other Than Income Tax

	2010	2009	2008
Current PRT expense	$ 69	$ 70	$ 210
Deferred PRT expense (recovery)	28	15	(67)
Provincial capital taxes and surcharges	22	21	35
	$ 119	$ 106	$ 178

Income Tax

The provision for income tax is as follows:

	2010	2009	2008
Current income tax – North America	$ 432	$ 28	$ 33
Current income tax – North Sea	203	278	340
Current income tax – Offshore West Africa	63	82	128
Current income tax expense	698	388	501
Future income tax expense (recovery)	364	(99)	1,607
Income tax expense	$ 1,062	$ 289	$ 2,108

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:

	2010	2009	2008
Canadian statutory income tax rate	28.1%	29.1%	29.8%
Income tax provision at statutory rate	$ 809	$ 576	$ 2,166
Effect on income taxes of:			
Deductible UK PRT	(49)	(43)	(72)
Foreign and domestic tax rate differentials	1	(127)	(5)
North America income tax rate and other legislative changes	–	(19)	(19)
Côte d’Ivoire income tax rate changes	–	–	(22)
Non-taxable portion of foreign exchange (gain) loss	(17)	(92)	127
Stock options exercised in shares	168	27	6
Non-deductible Offshore West Africa impairment charge	129	14	–
Other	21	(47)	(73)
Income tax expense	$ 1,062	$ 289	$ 2,108

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

		2010		2009
Future income tax liabilities				
Property, plant and equipment	$	7,525	$	6,992
Timing of partnership items		988		1,127
Unrealized foreign exchange gain on long-term debt		194		152
Other		–		31
Future income tax assets				
Asset retirement obligations		(525)		(499)
Loss carryforwards for income tax		(148)		(84)
Stock-based compensation		–		(83)
Unrealized risk management activities		(92)		(69)
Other		(105)		–
Deferred PRT		3		(26)
Net future income tax liability		7,840		7,541
Less: current portion of future income tax asset		(59)		(146)
Future income tax liability	$	7,899	$	7,687

During 2010, future income tax expense included a charge of $83 million related to enacted changes in Canada to the taxation of stock options surrendered by employees for cash.

During 2009, enacted income tax rate changes resulted in a reduction of future income tax liabilities of $19 million in British Columbia.

During 2008, enacted income tax rate changes resulted in a reduction of future income tax liabilities of approximately $19 million in British Columbia and approximately $22 million in Côte d'Ivoire.

The Company is subject to income tax reassessments arising in the normal course. The Company does not believe that any liabilities that might ultimately arise from these reassessments will be material.

8. 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

	2010			2009		
Common shares	Number of shares (thousands) (1)		Amount	Number of shares (thousands) (1)		Amount
Balance – beginning of year	1,084,654	$	2,834	1,081,982	$	2,768
Issued upon exercise of stock options	8,208		170	2,672		24
Previously recognized liability on stock options exercised for common shares	–		149	–		42
Cancellation of common shares	(14)		–	–		–

Purchase of common shares under Normal Course Issuer Bid	(2,000)	(6)	–	–
Balance – end of year	1,090,848	$ 3,147	1,084,654	$ 2,834

(1) Restated to reflect two-for-one common share split in May 2010.

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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.

On March 1, 2011, the Board of Directors set the Company's regular quarterly dividend at $0.09 per common share (2010 – $0.075 per common share, 2009 – $0.053 per common share).

Normal Course Issuer Bid

In 2010, the Company announced a 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 commencing April 6, 2010 and ending April 5, 2011, up to 27,163,940 common shares or 2.5% of the common shares of the Company outstanding at March 17, 2010. During 2010, the Company purchased 2,000,000 common shares for cancellation at an average price of $33.77 per common share, for a total cost of $68 million. Retained earnings was reduced by $62 million, representing the excess of the purchase price of the common shares over their average carrying value. The Company did not purchase any common shares for cancellation in 2009 and 2008.

Share split

The Company's shareholders passed a Special Resolution subdividing the common shares of the Company on a two-for-one basis at the Company's Annual and Special Meeting held on May 6, 2010 with such subdivision taking effect in May 2010. All common share, per common share, and stock option amounts have been restated to reflect the share split.

Stock Options

The Company's Option Plan provides for the 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 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 of the option.

The following table summarizes information relating to stock options outstanding at December 31, 2010 and 2009:

	2010			2009		
	Stock options (thousands) (1)		Weighted average exercise price (1)	Stock options (thousands) (1)		Weighted average exercise price (1)
Outstanding – beginning of year	64,211	$	29.27	61,924	$	25.97
Granted	16,168	$	40.68	13,472	$	33.96
Surrendered for cash settlement	(2,741)	$	21.00	(5,666)	$	13.66
Exercised for common shares	(8,208)	$	20.66	(2,672)	$	9.00
Forfeited	(2,586)	$	32.30	(2,847)	$	29.78
Outstanding – end of year	66,844	$	33.31	64,211	$	29.27
Exercisable – end of year	23,668	$	30.64	21,937	$	26.95

(1) Restated to reflect two-for-one common share split in May 2010.

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The range of exercise prices of stock options outstanding and exercisable at December 31, 2010 was as follows:

	Stock options outstanding				Stock options exercisable		
Range of exercise prices	Stock options outstanding (thousands)	Weighted average remaining term (years)		Weighted average exercise price	Stock options exercisable (thousands)		Weighted average exercise price
$12.34 – $14.99	69	0.05	$	12.69	69	$	12.69
$15.00 – $19.99	249	0.31	$	16.54	244	$	16.54
$20.00 – $24.99	11,599	3.09	$	23.19	4,171	$	23.10
$25.00 – $29.99	6,589	0.99	$	28.94	4,546	$	28.85
$30.00 – $34.99	21,055	3.10	$	33.00	7,979	$	31.70
$35.00 – $39.99	14,615	3.00	$	36.02	6,267	$	35.36
$40.00 – $44.99	11,287	5.05	$	42.24	–	$	–
$45.00 – $46.25	1,381	3.53	$	46.25	392	$	46.25
	66,844	3.20	$	33.31	23,668	$	30.64

9. ACCUMULATED OTHER COMPREHENSIVE LOSS

The components of accumulated other comprehensive loss, net of taxes, were as follows:

		2010		2009
Derivative financial instruments designated as cash flow hedges	$	48	$	76
Foreign currency translation adjustment		(215)		(180)
	$	(167)	$	(104)

During the next 12 months, $40 million is expected to be reclassified from accumulated other comprehensive loss, reducing net earnings.

10. CAPITAL DISCLOSURES

The Company does not have any externally imposed regulatory capital requirements for managing capital. The Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived non-GAAP financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current and long-term debt divided by the sum of the carrying value of shareholders' equity plus current and long-term debt. The Company aims over time to maintain its debt to book capitalization ratio in the range of 35% to 45%. However, the Company may exceed the high end of such target range if it is investing in capital projects, undertaking acquisitions, or in periods of lower commodity prices. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At December 31, 2010, the ratio is below the target range at 29%.

Readers are cautioned that the debt to book capitalization ratio is not defined by GAAP and this financial measure may not be comparable to similar measures presented by other companies. Further, there can be no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure in the future.

		2010		2009
Long-term debt	$	8,499	$	9,658
Total shareholders' equity	$	20,985	$	19,426
Debt to book capitalization		29%		33%

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11. NET EARNINGS PER COMMON SHARE

	2010	2009	2008
Weighted average common shares outstanding – basic and diluted (thousands of shares) (1)	1,088,096	1,083,850	1,081,294
Net earnings – basic and diluted	$ 1,697	$ 1,580	$ 4,985
Net earnings per common share – basic and diluted (1)	$ 1.56	$ 1.46	$ 4.61

(1) Restated to reflect two-for-one common share split in May 2010.

12. FINANCIAL INSTRUMENTS

The carrying values of the Company's financial instruments by category are as follows:

		2010	
Asset (liability)	Loans and receivables at amortized cost	Held for trading at fair value	Other financial liabilities at amortized cost
Cash and cash equivalents	$ –	$ 22	$ –
Accounts receivable	1,481	–	–
Accounts payable	–	–	(274)
Accrued liabilities	–	–	(2,163)
Other long-term liabilities	–	(451)	(91)
Long-term debt	–	–	(8,499)
	$ 1,481	$ (429)	$ (11,027)

		2009	
Asset (liability)	Loans and receivables at amortized cost	Held for trading at fair value	Other financial liabilities at amortized cost
Cash and cash equivalents	$ –	$ 13	$ –
Accounts receivable	1,148	–	–
Accounts payable	–	–	(240)
Accrued liabilities	–	–	(1,522)
Other long-term liabilities	–	(309)	(167)
Long-term debt	–	–	(9,658)
	$ 1,148	$ (296)	$ (11,587)

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The carrying value of the Company's financial instruments approximates their fair value, except for fixed-rate long-term debt as noted below. The fair values of the Company's financial assets and liabilities are outlined below:

	2010		
	Carrying value	Fair value	
Asset (liability) (1)		Level 1	Level 2
Other long-term liabilities	$ (451)	$ –	$(451)
Fixed-rate long-term debt(2) (3)	(7,063)	(7,835)	–
	$ (7,514)	$ (7,835)	$(451)

	2009		
	Carrying value	Fair value	
Asset (liability) (1)		Level 1	Level 2
Other long-term liabilities	$ (309)	$ –	$(309)
Fixed-rate long-term debt(2) (3)	(7,761)	(8,212)	–
	$ (8,070)	$ (8,212)	$(309)

(1) Excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities).

(2) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $61 million (2009 – $38 million) to reflect the fair value impact of hedge accounting.

(3) The fair value of fixed-rate long-term debt has been determined based on quoted market prices.

Risk Management

The changes in estimated fair values of derivative financial instruments included in the net risk management asset (liability) were recognized in the financial statements as follows:

Asset (liability)	2010 Risk management mark-to-market	2009 Risk management mark-to-market
Balance – beginning of year	$ (309)	$ 2,119
Net cost of outstanding put options	106	–
Net change in fair value of outstanding derivative financial instruments attributable to:		
Risk management activities	25	(1,991)
Interest expense	30	(25)
Foreign exchange	(101)	(338)
Other comprehensive income	(41)	(78)
Settlement of interest rate swaps and other	(55)	4
	(345)	(309)
Add: put premium financing obligations (1)	(106)	–

Balance – end of year		(451)		(309)
Less: current portion		(222)		(182)
	$	(229)	$	(127)

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

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

	2010	2009	2008
Net realized risk management (gain) loss	$ (96)	$ (1,253)	$ 1,860
Net unrealized risk management (gain) loss	(25)	1,991	(3,090)
	$ (121)	$ 738	$ (1,230)

Financial Risk Factors

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

Commodity price risk management

The Company uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases. At December 31, 2010, the Company had the following derivative financial instruments outstanding to manage its commodity price exposures:

i) Sales Contracts

	Remaining term		Volume	Weighted average price		Index
Crude oil						
Crude oil price collars	Jan 2011	–Dec 2011	50,000 bbl/d	US$70.00	–US$102.23	WTI
Crude oil puts (1)	Jan 2011	–Dec 2011	100,000 bbl/d		US$70.00	WTI

(1) Crude oil put options have a cost of US$106 million.

ii) Purchase Contracts

	Remaining term		Volume	Weighted average fixed rate	Floating index
Natural gas					
Swaps – floating to fixed	Jan 2011	–Dec 2011	125,000 GJ/d	C$4.87	AECO

The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

The natural gas derivative financial instruments designated as hedges as at December 31, 2010 were classified as cash flow hedges.

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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 floating rate long-term debt. The Company enters into interest rate swap contracts 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. At December 31, 2010, the Company had the following interest rate swap contracts outstanding:

	Remaining term	Amount ($ millions)	Fixed rate	Floating rate
Interest rate (1) (2)				
Swaps – floating to fixed	Jan 2011 – Feb 2012	C$200	1.4475%	3 month CDOR (3)

(1) During 2010, the Company unwound US$350 million of 4.9% interest rate swaps for proceeds of US$54 million.

(2) During 2010, the Company unwound C$300 million of 1.0680% interest rate swaps for nominal consideration.

(3) Canadian Dealer Offered Rate

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies in its subsidiaries and in the carrying value of its self-sustaining foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt and working capital. 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. At December 31, 2010, the Company had the following cross currency swap contracts outstanding:

	Remaining term	Amount ($ millions)	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency					
Swaps (1)	Jan 2011 – Jul 2011	US$150	0.999	6.70%	7.70%
	Jan 2011 – Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2011 – May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2011 – Mar 2038	US$550	1.170	6.25%	5.76%

(1) Subsequent to December 31, 2010, the Company entered into cross currency swap contracts for US$50 million with an exchange rate of $0.994 (US$/C$) and average interest rates of 6.70% (US$) and 7.88% (C$) for the period January to July 2011.

All cross currency swap derivative financial instruments designated as hedges at December 31, 2010 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2010, the Company had US$1,162 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less.

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Financial instrument sensitivities

The following table summarizes the annualized sensitivities of the Company's net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at December 31, 2010, resulting from changes in the specified variable, with all other variables held constant. These sensitivities are prepared on a different basis than those sensitivities disclosed in the Company's other continuous disclosure documents, and do not represent the impact of a change in the variable on the operating results of the Company taken as a whole. Further, these sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities. In addition, changes in fair value generally can not be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

	2010			
		Impact on net earnings		Impact on other comprehensive income
Commodity price risk				
Increase WTI US$1.00/bbl	$	(7)	$	–
Decrease WTI US$1.00/bbl	$	7	$	–
Increase AECO C$0.10/Mcf	$	–	$	3
Decrease AECO C$0.10/Mcf	$	–	$	(3)
Interest rate risk				
Increase interest rate 1%	$	(8)	$	22
Decrease interest rate 1%	$	8	$	(31)
Foreign currency exchange rate risk				
Increase exchange rate by US$0.01	$	(27)	$	–
Decrease exchange rate by US$0.01	$	27	$	–

b) Credit Risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

Counterparty credit risk management

The Company's 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 these risks by reviewing 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. At December 31, 2010, substantially all of the Company's accounts receivables were due within normal trade terms.

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 entering into agreements with counterparties that are substantially all investment grade financial institutions and other entities. At December 31, 2010, the Company had net risk management assets of $nil with specific counterparties related to derivative financial instruments (December 31, 2009 – $7 million).

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c) Liquidity Risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, and access to debt capital markets, to meet obligations as they become due. Due to fluctuations in the timing of the receipt and/or disbursement of operating cash flows, the Company believes it has adequate bank credit facilities to provide liquidity.

The maturity dates for financial liabilities are as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 274	$ –	$ –	$ –
Accrued liabilities	$ 2,163	$ –	$ –	$ –
Risk management	$ 222	$ 32	$ 96	$ 101
Other long-term liabilities	$ 25	$ 25	$ 41	$ –
Long-term debt (1)	$ 398	$ 348	$ 1,546	$ 4,774

(1) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,436 million of revolving bank credit facilities due to the extendable nature of the facilities.

13. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2011	2012	2013	2014	2015	Thereafter
Product transportation and pipeline	$ 228	$ 199	$ 172	$ 164	$ 152	$ 932
Offshore equipment operating leases	$ 141	$ 98	$ 97	$ 97	$ 81	$ 168
Offshore drilling	$ 7	$ –	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 18	$ 17	$ 19	$ 28	$ 27	$ 7,123
Office leases	$ 27	$ 27	$ 28	$ 28	$ 32	$ 339
Other	$ 102	$ 66	$ 19	$ 16	$ 24	$ 10

(1) 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 2011 – 2015 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

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

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14. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Changes in non-cash working capital were as follows:

	2010		2009		2008	
Changes in non-cash working capital						
Accounts receivable, inventory, prepaids and other	$	(340)	$	(276)	$	111
Accounts payable		37		(151)		(4)
Accrued liabilities		576		(429)		(15)
Net changes in non-cash working capital	$	273	$	(856)	$	92
Relating to:						
Operating activities	$	149	$	(235)	$	(189)
Financing activities		(5)		(12)		46
Investing activities		129		(609)		235
	$	273	$	(856)	$	92

Other cash flow information:		2010		2009		2008
Interest paid	$	471	$	516	$	574
Taxes other than income tax paid	$	102	$	52	$	300
Current income tax paid	$	111	$	216	$	258

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15. SEGMENTED INFORMATION

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

The Company's Oil Sands Mining and Upgrading is a separate segment from Exploration and Production activities as the bitumen is recovered through mining operations.

Midstream activities include the Company's pipeline operations and an electricity co-generation system. Activities that are not included in the above segments are reported in the segmented information as other. Inter-segment eliminations include internal transportation, electricity charges and natural gas sales.

	Exploration and Production										
	North America			North Sea			Offshore West Africa				T
	2010	2009	2008	2010	2009	2008	2010	2009	2008	2010	20
Segmented revenue	$ 9,713	$ 7,973	$ 13,496	$ 1,058	$ 961	$ 1,769	$ 884	$ 913	$ 944	$ 11,655	$ 9
Less: royalties	(1,267)	(825)	(1,876)	(2)	(2)	(4)	(62)	(81)	(143)	(1,331)	(
Segmented revenue, net of royalties	8,446	7,148	11,620	1,056	959	1,765	822	832	801	10,324	8
Segmented expenses											
Production	1,675	1,748	1,881	385	376	457	167	179	102	2,227	2
Transportation and blending	1,761	1,213	1,975	8	8	10	1	1	1	1,770	
Depletion, depreciation and amortization	2,336	2,060	2,236	303	261	317	1,023	335	132	3,662	2
Asset retirement obligation accretion	46	41	42	33	24	27	6	4	2	85	6
Realized risk management activities	(96)	(880)	1,861	–	(373)	(1)	–	–	–	(96)	(
Total segmented expenses	5,722	4,182	7,995	729	296	810	1,197	519	237	7,648	4
Segmented earnings (loss) before the	$ 2,724	$ 2,966	$ 3,625	$ 327	$ 663	$ 955	$ (375)	$ 313	$ 564	$ 2,676	$ 3

following
Non–segmented expenses
Administration
Stock-based compensation expense (recovery)
Interest, net
Unrealized risk management activities
Foreign exchange (gain) loss
Total non-segmented expenses
Earnings before taxes
Taxes other than income tax
Current income tax expense
Future income tax expense (recovery)
Net earnings

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	Oil Sands Mining and Upgrading			Midstream			Inter–segment elimination and other			Total		
	2010	2009	2008	2010	2009	2008	2010	2009	2008	2010	2009	2008
Segmented revenue	$ 2,649	$ 1,253	$ –	$ 79	$ 72	$ 77	$ (61)	$ (94)	$ (113)	$ 14,322	$ 11,078	$ 16,173
Less: royalties	(90)	(36)	–	–	–	–	–	8	6	(1,421)	(936)	(2,017)
Segmented revenue, net of royalties	2,559	1,217	–	79	72	77	(61)	(86)	(107)	12,901	10,142	14,156
Segmented expenses												
Production	1,208	683	–	22	19	25	(10)	(18)	(14)	3,447	2,987	2,451
Transportation and blending	61	41	–	–	–	–	(48)	(45)	(50)	1,783	1,218	1,936
Depletion, depreciation and amortization	366	187	–	8	9	8	–	(33)	(10)	4,036	2,819	2,683
Asset retirement obligation accretion	22	21	–	–	–	–	–	–	–	107	90	71
Realized risk management activities	–	–	–	–	–	–	–	–	–	(96)	(1,253)	1,860
Total segmented expenses	1,657	932	–	30	28	33	(58)	(96)	(74)	9,277	5,861	9,001
Segmented earnings (loss) before the following	$ 902	$ 285	$ –	$ 49	$ 44	$ 44	$ (3)	$ 10	$ (33)	3,624	4,281	5,155
Non–segmented expenses												
Administration										210	181	180
Stock-based compensation expense (recovery)										294	355	(52)
Interest, net										449	410	128
Unrealized risk management activities										(25)	1,991	(3,090)
										(182)	(631)	718

Foreign exchange (gain) loss			
Total non–segmented expenses	746	2,306	(2,116)
Earnings before taxes	2,878	1,975	7,271
Taxes other than income tax	119	106	178
Current income tax expense	698	388	501
Future income tax expense (recovery)	364	(99)	1,607
Net earnings	$ 1,697	$ 1,580	$ 4,985

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Capital Expenditures

	2010 Net expenditures	2010 Non cash and fair value changes(1)	2010 Capitalized costs	2009 Net expenditures	2009 Non cash and fair value changes(1)	2009 Capitalized costs
Exploration and Production						
North America	$ 4,369	$ 386	$ 4,755	$1,663	$ 65	$ 1,728
North Sea	149	(41)	108	168	146	314
Offshore West Africa	246	(10)	236	544	111	655
Other	3	–	3	2	–	2
	4,767	335	5,102	2,377	322	2,699
Oil Sands Mining and Upgrading(2)	535	(59)	476	553	355	908
Midstream	7	–	7	6	–	6
Head office	18	–	18	13	–	13
	$ 5,327	$ 276	$ 5,603	$2,949	$ 677	$ 3,626

(1) Asset retirement obligations, future income tax adjustments related to differences between carrying value and tax value, and other fair value adjustments.

(2) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest, stock-based compensation, and the impact of intersegment eliminations.

Segmented Assets

	2010	2009
Exploration and Production		
North America	$ 25,499	$ 22,994
North Sea	1,674	1,968
Offshore West Africa	1,186	2,033
Other	46	42
Oil Sands Mining and Upgrading	13,865	13,621
Midstream	338	306
Head office	61	60
	$ 42,669	$ 41,024

16. Subsequent Events

On January 6, 2011, the Company suspended synthetic crude oil production at its Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. Production will recommence once plant operating capacity is restored and all necessary regulatory and operating approvals are received.

The Company believes that it has adequate insurance coverage to mitigate all significant property damage related losses. The Company also maintains business interruption coverage, subject to a waiting period, which it believes will mitigate operating losses related to on-going operations.

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17. 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 as 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 (loss) as reported:

(millions of Canadian dollars, except per common share amounts)	Notes		2010		2009		2008
Net earnings – Canadian GAAP		$	1,697	$	1,580	$	4,985
Adjustments							
Depletion, net of taxes of $365 million (2009 – $7 million, 2008 – $2,503 million)	(A,B,C,D)		1,128		(273)		(6,169)
Stock-based compensation, net of taxes of $107 million (2009 – $51 million, 2008 – $32 million)	(B)		(41)		(154)		(76)
Future income taxes	(F)		–		–		234
Net earnings (loss) – US GAAP		$	2,784	$	1,153	$	(1,026)
Net earnings (loss) – US GAAP per common share (1)							
Basic		$	2.56	$	1.06	$	(0.95)
Diluted	(E)	$	2.54	$	1.06	$	(0.95)

(1) Restated to reflect two-for-one common share split in May 2010.

Comprehensive income (loss) under US GAAP would be as follows:

(millions of Canadian dollars)		2010		2009		2008
Comprehensive income – Canadian GAAP	$	1,634	$	1,214	$	5,175
US GAAP earnings adjustments		1,087		(427)		(6,011)
Comprehensive income (loss) – US GAAP	$	2,721	$	787	$	(836)

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

			2010				
(millions of Canadian dollars)	Notes		Canadian GAAP		Increase (Decrease)		US GAAP
Current assets		$	2,172	$	–	$	2,172
Property, plant and equipment	(A,B,C,D)		40,472		(7,324)		33,148
Other long-term assets	(G)		25		44		69
		$	42,669	$	(7,280)	$	35,389
Current liabilities	(B)	$	3,156	$	354	$	3,510
Long-term debt	(G)		8,499		44		8,543
Other long-term liabilities	(B)		2,130		9		2,139
Future income tax	(A,B,C,D)		7,899		(2,105)		5,794
Share capital			3,147		–		3,147

Retained earnings	18,005	(5,582)	12,423
Accumulated other comprehensive income	(167)	–	(167)
	$ 42,669	$ (7,280)	$ 35,389

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			2009	
(millions of Canadian dollars)	Notes	Canadian GAAP	Increase (Decrease)	US GAAP
Current assets		$ 1,891	$ 103	$ 1,994
Property, plant and equipment	(A,B,C,D)	39,115	(8,824)	30,291
Other long-term assets	(G)	18	49	67
		$ 41,024	$(8,672)	$ 32,352
Current liabilities	(B)	$ 2,405	$ 387	$ 2,792
Long-term debt	(G)	9,658	49	9,707
Other long-term liabilities	(B)	1,848	35	1,883
Future income tax	(A,B,C,D)	7,687	(2,474)	5,213
Share capital		2,834	–	2,834
Retained earnings		16,696	(6,669)	10,027
Accumulated other comprehensive income		(104)	–	(104)
		$ 41,024	$(8,672)	$ 32,352

Notes:

(A) Under Canadian full cost accounting guidance, costs capitalized in each country cost centre are limited to an amount equal to the future net revenues from proved plus probable reserves using estimated future prices and costs discounted at the risk-free rate, plus the carrying amount of unproved properties and major development projects (the "ceiling test") as described in note 1(I). 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 using the average first-day-of-the-month price during the previous twelve-month period and costs as at the balance sheet date, and are discounted at 10%. Capitalized costs and future net revenues are determined on a net of tax basis. In addition, beginning in 2009, the Company's Oil Sands Mining and Upgrading activities would have been included in the Company's US GAAP full cost oil and gas cost centre for Canada for ceiling test purposes. These differences in applying the ceiling test to current and prior years would have resulted in the recognition of ceiling test impairments under US GAAP, which would have reduced property, plant and equipment by $8,396 million in 2010 (2009 – $8,951 million, 2008 – $8,697 million).

For the year ended December 31, 2010, US GAAP net earnings would have increased by $66 million (2009 – decreased by $815 million, 2008 – decreased by $6,164 million), net of income taxes of $24 million (2009 – $178 million, 2008 – $2,501 million) to reflect the impact of a current year ceiling test impairment. In addition, the impact of prior ceiling test impairments would have increased US GAAP net earnings by $359 million (2009 – $551 million, 2008 – $3 million), net of income taxes of $154 million (2009 – $188 million, 2008 – $1 million) to reflect the impact of lower depletion charges.

During 2009, the US Securities and Exchange Commission adopted revisions to its oil and gas reporting disclosures contained in Regulation S-K and Topic 932 "Extractive Activities – Oil and Gas" (a summary of the requirements included in Regulation S-X). These revisions impacted the reserves used in the Company's calculation of the ceiling test under US GAAP at December 31, 2009 and 2010 and the calculation of depletion in 2010. In addition, oil and gas activities were determined based on the end product, rather than the method of extraction. As a result, the Company's Oil Sands Mining and Upgrading operations were included in its full cost oil and gas cost center for Canada. These revisions were effective for filings made on or after January 1, 2010, and were applied prospectively with no retroactive restatement. For the year ended December 31, 2010, US GAAP net earnings would have increased by $708 million, net of income taxes of $237 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(P). Under US GAAP, effective January 1, 2006, the Company would have adopted Financial Accounting Standards Board Statement (FASB) Topic 718 "Compensation – Stock Compensation" (previously 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, 2010, US GAAP net earnings would have increased by $66 million (2009 – decreased by $154 million, 2008 – decreased by $76 million), net of income taxes of $nil (2009 – $51 million, 2008 – $32 million) related to the different valuation methodologies. In addition, US GAAP net earnings would have decreased by $1 million (2009 – $1 million, 2008 – $nil), net of income taxes of $nil (2009 and 2008 – $nil) related to the impact of the change in capitalized stock-based compensation on depletion, depreciation and amortization expenses.

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Future income tax expense would have included a charge of $107 million related to enacted changes in Canada to the taxation of stock options surrendered by employees for cash.

(C)Under US GAAP, the foreign currency component of a business combination is not eligible for cash flow hedging. The impact of prior year adjustments would have decreased US GAAP net earnings by $3 million for the year ended December 31, 2010 (2009 – $7 million, 2008 – $8 million), net of income taxes of $2 million (2009 and 2008 – $3 million), to reflect the impact of higher depletion charges.

(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. As a result of applying US GAAP, an additional $27 million would have been capitalized to property, plant and equipment in 2004. During 2009, Horizon Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest ceased anddepletion, depreciation and amortization of these assets commenced. For the year ended December 31, 2010, US GAAP net earnings would have decreased by $1 million (2009 – $1 million, 2008 – $nil), net of income taxes of $nil (2009 and 2008 – $nil).

(E)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 as the Company has recorded the potential settlement of the stock options as a liability. Under US GAAP Topic 260 "Earnings Per Share" (previously 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, 2010, 8 million additional shares would have been included in the calculation of diluted earnings per share for US GAAP (2009 and 2008 – nil additional shares).

(F)Under Canadian GAAP, the effects of income tax changes are recognized when the changes are considered substantively enacted. Under US GAAP, the income tax changes would not be recognized until the changes are enacted into law. For the year ended December 31, 2008, the differences between substantively enacted and enacted tax legislation resulted in a difference in timing of the recognition of a $234 million future income tax recovery.

(G)Under Canadian GAAP, debt issue costs on long-term debt must be included in the carrying value of the related debt. Under US GAAP, these items must be recorded as a deferred charge. Application of US GAAP would have resulted in the balance sheet reclassification of $44 million of debt issue costs from long-term debt to deferred charges in 2010 (2009 – $49 million, 2008 – $55 million).

(H)In December 2007, the FASB issued Topic 805 "Business Combinations" (previously FAS 141(R) "Business Combinations"), which replaced FAS 141 effective for fiscal years beginning after December 15, 2009. Topic 805 retains the purchase method of accounting and requires assets acquired and liabilities assumed in a business combination to be measured at fair value at the date of acquisition. The standard also requires acquisition-related costs and restructuring costs to be recognized separately from the business combination. This standard is to be applied prospectively to all business combinations subsequent to the effective date and does not require restatement of previously completed business combinations. The adoption of this standard did not result in a US GAAP reconciling item.

(I)Effective January 1, 2011 the Company will be preparing consolidated financial statements in accordance with IFRS and a reconciliation to US GAAP will not be required. As a result, SAB Topic 11M, "Disclosure of the Impact that Recently Issued Accounting Standards Will Have on the Financial Statements of the Registrant When Adopted in a Future Period" was not provided for 2010.

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MANAGEMENT'S DISCUSSION AND ANALYSIS

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "int "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "se expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, and other guidance provided throughout this Management's Discussion and Analysis ("MD&A") including the information in the "Outlook" section and the sensitivity analysis constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands resumption of production and future expansion, Primrose, Pelican Lake, Olowi Field (Offshore Gabon), the Kirby Thermal Oil Sands Project, the Keystone Pipeline US Gulf Coast expansion, and the construction and operation of the North West Redwater bitumen refinery also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year if necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks and the reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil and natural gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected difficulties in mining, extracting or upgrading the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, natural gas and natural gas liquids (“NGLs”) not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company’s provision for taxes; and other circumstances affecting revenues and expenses. The Company’s operations have been, and in the future may be, affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company’s assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, 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 the “Risks and Uncertainties” section of this MD&A.

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

SPECIAL NOTE REGARDING NON-GAAP FINANCIAL MEASURES
Management's Discussion and Analysis includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations, cash production costs and net asset value. These financial measures are not defined by generally accepted accounting principles in Canada ("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 non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with Canadian GAAP, in the "Financial Highlights" section of this MD&A. The derivation of cash production costs is included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

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, 2010. The Company's consolidated financial statements and this MD&A have been prepared in accordance with Canadian GAAP in effect as at and for the year ended December 31, 2010. Effective January 1, 2011, the Company will adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board. Unless otherwise stated, references to Canadian GAAP do not incorporate the impact of any changes to accounting standards that will be required due to changes required by IFRS. A reconciliation of Canadian GAAP to generally accepted accounting principles in the United States ("US GAAP") is included in note 17 to the consolidated financial statements. All dollar amounts are referenced in millions of Canadian dollars, except where otherwise noted. Common share data has been restated to reflect the two-for-one share split in May 2010. 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 conversion method primarily applicable at the burner tip and does not represent the value equivalency at the wellhead. Production volumes and per barrel statistics are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices are net of transportation and blending costs and exclude the effect of risk management activities. Production on an "after royalty" or "net" basis is also presented for information purposes only. The following discussion and analysis refers primarily to the Company's 2010 financial results compared to 2009 and 2008, unless otherwise indicated. In addition, this MD&A details the Company's capital program and outlook for 2011. Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2010, its Annual Information Form for the year ended December 31, 2010, and its audited consolidated financial statements for the year ended December 31, 2010 is available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. This MD&A is dated March 1, 2011.

ABBREVIATIONS

AECO	Alberta natural gas reference location
AIF	Annual Information Form
API	Specific gravity measured in degrees on the American Petroleum Institute scale
ARO	Asset retirement obligations
bbl	barrels
bbl/d	barrels per day
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
BOE	barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
Bitumen	Solid or semi-solid with viscosity greater than 10,000 centipoise
Brent	Dated Brent

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C$	Canadian dollars
CAPEX	Capital expenditures
CBM	Coal Bed Methane
CICA	Canadian Institute of Chartered Accountants
CO2	Carbon dioxide
CO2e	Carbon dioxide equivalents
Canadian GAAP	Generally accepted accounting principles in Canada
CSS	Cyclic steam stimulation
EOR	Enhanced oil recovery
E&P	Exploration and Production
FPSO	Floating Production, Storage and Offloading Vessel
GHG	Greenhouse gas
GJ	gigajoules
GJ/d	gigajoules per day
Horizon	Horizon Oil Sands
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas
Mbbl	thousand barrels
Mbbl/d	thousand barrels per day
MBOE	thousand barrels of oil equivalent
MBOE/d	thousand barrels of oil equivalent per day
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMbbl	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MMcfe	millions of cubic feet equivalent
NGLs	Natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
PRT	Petroleum Revenue Tax
SAGD	Steam-Assisted gravity drainage
SCO	Synthetic crude oil
SEC	United States Securities and Exchange Commission
Tcf	trillion cubic feet
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States
US GAAP	Generally accepted accounting principles in the United States
US$	United States dollars
WCS	Western Canadian Select
WCSB	Western Canadian Sedimentary Basin
WCS Heavy Differential	WCS Heavy Differential from WTI
WTI	West Texas Intermediate

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OBJECTIVES AND STRATEGY

The Company's objectives are 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/or acquisition of new reserves. The Company strives to meet these objectives 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 value. The Company allocates its capital by maintaining:

§ Balance among its products, namely natural gas, light and medium crude oil and NGLs, Pelican Lake heavy crude oil (2), primary heavy crude oil, bitumen (thermal oil) and SCO;
§ Balance among near-, mid- and long-term projects;
§ Balance among acquisitions, exploitation and exploration; and
§ Balance between sources and terms of debt financing and maintenance of a strong balance sheet.

(1) Discounted value of crude oil and natural gas reserves plus value of unproved land, less net debt.

(2) Pelican Lake heavy crude oil is 14–17º API oil, which receives medium quality crude netbacks due to lower production costs and lower royalty rates.

The Company's three-phase crude oil marketing strategy includes:
§ Blending various crude oil streams with diluents to create more attractive feedstock;
§ Supporting and participating in pipeline expansions and/or new additions; and
§ Supporting and participating in projects that will increase the downstream conversion capacity for heavy crude oil.

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

The Company is committed to maintaining a strong balance sheet and flexible capital structure. The Company believes it has built the necessary financial capacity to complete all of its growth projects. Additionally, the Company's risk management hedge program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs.

Strategic accretive acquisitions 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.

Highlights for the year ended December 31, 2010 include the following:

§ Achieved net earnings of $1.7 billion, adjusted net earnings from operations of $2.6 billion, and cash flow from operations of $6.3 billion;
§ Achieved record yearly production of 632,191 BOE/d;
§ Achieved annual crude oil and natural gas production guidance;
§ Drilled a record 654 net primary heavy crude oil wells;
§ Received Board of Directors sanction and commenced construction of Phase 1 of the Kirby In Situ Oil Sands project;
§

Acquired approximately $1.9 billion of crude oil and natural gas properties in the Company's core regions in Western Canada;

§ Submitted a joint proposal to the Government of Alberta to construct and operate a bitumen upgrading and refining facility;

§ Reduced long-term debt by $1.2 billion to $8.5 billion in 2010 from $9.7 billion in 2009;

§ Completed the subdivision of the Company's common shares on a two for one basis;

§ Purchased 2,000,000 common shares for a total cost of $68 million under a Normal Course Issuer Bid; and

§ Increased annual per share dividend payment to $0.30 from $0.21, our 10th consecutive year of dividend increases.

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NET EARNINGS AND CASH FLOW FROM OPERATIONS

Financial Highlights ($ millions, except per common share amounts)		2010		2009(1)		2008(1)
Revenue, before royalties	$	14,322	$	11,078	$	16,173
Net earnings	$	1,697	$	1,580	$	4,985
Per common share – basic and diluted	$	1.56	$	1.46	$	4.61
Adjusted net earnings from operations (2)	$	2,570	$	2,689	$	3,492
Per common share – basic and diluted	$	2.36	$	2.48	$	3.23
Cash flow from operations (3)	$	6,321	$	6,090	$	6,969
Per common share – basic and diluted	$	5.81	$	5.62	$	6.45
Dividends declared per common share	$	0.30	$	0.21	$	0.20
Total assets	$	42,669	$	41,024	$	42,650
Total long-term liabilities	$	18,528	$	19,193	$	20,856
Capital expenditures, net of dispositions	$	5,506	$	2,997	$	7,451

(1) Per common share amounts have been restated to reflect a two-for-one common share split in May 2010.

(2) Adjusted net earnings from operations is a non-GAAP measure 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 reconciliation “Adjusted Net Earnings from Operations” presented below 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.

(3) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items before working capital adjustments. 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. The reconciliation “Cash Flow from Operations” presented below lists the effects of certain non-cash items that are included in the Company’s financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings from Operations ($ millions)		2010		2009		2008
Net earnings as reported	$	1,697	$	1,580	$	4,985
Stock-based compensation expense (recovery), net of tax (a)(e)		294		261		(38)
Unrealized risk management (gain) loss, net of tax (b)		(16)		1,437		(2,112)
Unrealized foreign exchange (gain) loss, net of tax (c)		(160)		(570)		698
Gabon, Offshore West Africa ceiling test impairment (d)		672		–		–
Effect of statutory tax rate and other legislative changes on future income tax liabilities (e)		83		(19)		(41)
Adjusted net earnings from operations	$	2,570	$	2,689	$	3,492

(a) The Company's employee stock option plan provides for a cash payment option. Accordingly, the intrinsic value of outstanding vested options is recorded as a liability on the Company's balance sheet and periodic changes in the intrinsic value are recognized in net earnings or are capitalized to Oil Sands Mining and Upgrading construction costs.

(b) Derivative financial instruments are recorded at fair value on the balance sheet, with changes in fair value of non-designated hedges recognized in 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, offset by the impact of cross currency swap hedges, and are recognized in net earnings.

(d) Performance from the Olowi Field continues to be below expectations. As a result, the Company recognized a pre-tax ceiling test impairment charge of $726 million ($672 million after-tax) at December 31, 2010.

(e) All substantively enacted or enacted adjustments in applicable income tax rates and other legislative changes 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 and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted or enacted. During 2010, the Canadian Federal Government enacted changes to the taxation of stock options surrendered by employees for cash payments. As a result of the changes, the Company anticipates that Canadian based employees will no longer surrender their options for cash payments, resulting in a loss of future income tax deductions for the Company. The impact of this change was an $83 million charge to future income tax expense. Income tax rate changes during 2009 resulted in a reduction of future income tax liabilities of approximately $19 million in North America. Income tax rate changes during 2008 resulted in a reduction of future income tax liabilities of approximately $19 million in North America and $22 million in Côte d'Ivoire, Offshore West Africa.

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Cash Flow from Operations

($ millions)		2010		2009		2008
Net earnings	$	1,697	$	1,580	$	4,985
Non-cash items:						
Depletion, depreciation and amortization		4,036		2,819		2,683
Asset retirement obligation accretion		107		90		71
Stock-based compensation expense (recovery)		294		355		(52)
Unrealized risk management (gain) loss		(25)		1,991		(3,090)
Unrealized foreign exchange (gain) loss		(180)		(661)		832
Deferred petroleum revenue tax expense (recovery)		28		15		(67)
Future income tax expense (recovery)		364		(99)		1,607
Cash flow from operations	$	6,321	$	6,090	$	6,969

For 2010, the Company reported net earnings of $1,697 million compared to net earnings of $1,580 million for 2009 (2008 – $4,985 million). Net earnings for the year ended December 31, 2010 included net unrealized after-tax expenses of $873 million related to the effects of stock-based compensation, risk management activities, fluctuations in foreign exchange rates, the impact of a ceiling test impairment charge at Gabon, Offshore West Africa and the impact of statutory tax rate and other legislative changes on future income tax liabilities (2009 – $1,109 million after-tax expenses; 2008 – $1,493 million after-tax income). Excluding these items, adjusted net earnings from operations for the year ended December 31, 2010 decreased to $2,570 million from $2,689 million for 2009 (2008 – $3,492 million).

The decrease in adjusted net earnings from the year ended December 31, 2009 was primarily due to:

§ lower realized risk management gains;

§ higher depletion, depreciation and amortization expense;

§ lower natural gas sales volumes and netbacks; and

§ the impact of the stronger Canadian dollar, partially offset by

§ the impact of higher crude oil and NGL sales volumes and netbacks.

The impacts of stock-based compensation, unrealized risk management activities and changes in foreign exchange rates are expected to continue to contribute to significant volatility in consolidated net earnings and are discussed in detail in the relevant sections of this MD&A.

Cash flow from operations for the year ended December 31, 2010 increased to $6,321 million ($5.81 per common share) from $6,090 million ($5.62 per common share) for 2009 (2008 – $6,969 million; $6.45 per common share). The increase in cash flow from operations from 2009 was primarily due to:

§ the impact of higher crude oil and NGL sales volumes and netbacks, partially offset by

§ lower realized risk management gains;

§ lower natural gas sales volumes and netbacks;

- higher cash taxes; and
- the impact of the stronger Canadian dollar.

For the Company's Exploration and Production activities, the 2010 average sales price per bbl of crude oil and NGLs increased 14% to average $65.81 per bbl from $57.68 per bbl in 2009 (2008 – $82.41 per bbl), and the average natural gas price decreased 10% to average $4.08 per Mcf from $4.53 per Mcf for 2009 (2008 – $8.39 per Mcf). The Company's average sales price of SCO increased 10% to average $77.89 per bbl from $70.83 per bbl in 2009 (2008 – nil).

Total production of crude oil and NGLs before royalties increased 20% to 424,985 bbl/d from 355,463 bbl/d for 2009 (2008 – 315,667 bbl/d). The increase in crude oil and NGLs production was primarily due to higher volumes from the Company's bitumen (thermal oil) and Horizon operations.

Total natural gas production before royalties decreased 5% to average 1,243 MMcf/d from 1,315 MMcf/d for 2009 (2008 – 1,495 MMcf/d). The decrease in natural gas production primarily reflected natural production declines and the Company's strategic reduction in natural gas drilling activity in North America, partially offset by new production volumes from the Septimus facility in Northeast British Columbia and from production volumes from natural gas properties acquired during the year.

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Total crude oil and NGLs and natural gas production volumes before royalties increased 10% to average 632,191 BOE/d from 574,730 BOE/d for 2009 (2008 – 564,845 BOE/d). Total production for 2010 was within the Company's previously issued guidance.

SUMMARY OF QUARTERLY RESULTS

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

($ millions, except per common share amounts)

2010		Total	Dec 31	Sep 30	Jun 30	Mar 31(1)
Revenue, before royalties	$	14,322	$ 3,787	$ 3,341	$ 3,614	$ 3,580
Net earnings (loss)	$	1,697	$(416)	$ 580	$ 667	$ 866
Net earnings (loss) per common share						
– basic and diluted	$	1.56	$(0.38)	$ 0.53	$ 0.61	$ 0.80

2009		Total(1)	Dec 31(1)	Sep 30(1)	Jun 30(1)	Mar 31(1)
Revenue, before royalties	$	11,078	$ 3,319	$ 2,823	$ 2,750	$ 2,186
Net earnings	$	1,580	$ 455	$ 658	$ 162	$ 305
Net earnings per common share						
– basic and diluted	$	1.46	$ 0.42	$ 0.61	$ 0.15	$ 0.28

(1) Per common share amounts have been restated to reflect a two-for-one common share split in May 2010.

Volatility in quarterly net earnings (loss) over the eight most recently completed quarters was primarily due to:

§ Crude oil pricing – The impact of fluctuating demand, inventory storage levels and geopolitical uncertainties on worldwide benchmark pricing, and the impact of the WCS Heavy Differential from WTI ("WCS Differential") in North America.

§ Natural gas pricing – The impact of seasonal fluctuations in both the demand for natural gas and inventory storage levels, and the impact of increased shale gas production in the US, as well as fluctuations in imports of liquefied natural gas into the US.

§ Crude oil and NGLs sales volumes – Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, the results from the Pelican Lake water and polymer flood projects, and the commencement and ramp up of operations at Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore West Africa.

§ Natural gas sales volumes – Fluctuations in production due to the Company's strategic decision to reduce natural gas drilling activity in North America and the allocation of capital to higher return crude oil projects, as well as natural decline rates and the impact of acquisitions.

§ Production expense – Fluctuations primarily due to the impact of the demand for services, fluctuations in product mix, the impact of seasonal costs that are dependent on weather, production and cost optimizations in North America and the commencement of operations at Horizon and the Olowi Field in Offshore Gabon.

- § Depletion, depreciation and amortization – Fluctuations due to changes in sales volumes, proved reserves, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, the impact of the commencement of operations at Horizon and the Olowi Field and the impact of ceiling test impairments at the Olowi Field.

- § Stock-based compensation – Fluctuations due to the mark-to-market movements of the Company's stock-based compensation liability. Stock-based compensation expense (recovery) reflected fluctuations in the Company's share price.

- § Risk management – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.

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§ Foreign exchange rates – Changes in the Canadian dollar relative to the US dollar impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominately on US dollar denominated benchmarks. Fluctuations in unrealized foreign exchange gains and losses are recorded with respect to US dollar denominated debt and the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars, partially offset by the impact of cross currency swap hedges.

§ Income tax expense – Fluctuations in income tax expense (recovery) include statutory tax rate and other legislative changes substantively enacted or enacted in the various periods.

BUSINESS ENVIRONMENT

(Yearly average)	2010	2009	2008
WTI benchmark price (US$/bbl)	$ 79.55	$ 61.93	$ 99.65
Dated Brent benchmark price (US$/bbl)	$ 79.50	$ 61.61	$ 96.99
WCS blend differential from WTI (US$/bbl)	$ 14.26	$ 9.64	$ 20.03
WCS blend differential from WTI (%)	18%	16%	20%
SCO price (US$/bbl)	$ 78.56	$ 61.51	$ 102.48
Condensate benchmark price (US$/bbl)	$ 81.81	$ 60.60	$ 100.10
NYMEX benchmark price (US$/MMBtu)	$ 4.42	$ 4.03	$ 8.95
AECO benchmark price (C$/GJ)	$ 3.91	$ 3.91	$ 7.71
US / Canadian dollar average exchange rate	$ 0.9709	$ 0.8760	$ 0.9381
US / Canadian dollar year end exchange rate	$ 1.0054	$ 0.9555	$ 0.8166

Commodity Prices

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Brent indices. Canadian natural gas pricing is primarily based on Alberta AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized price is also highly sensitive to fluctuations in foreign exchange rates. The average value of the Canadian dollar in relation to the US dollar fluctuated significantly throughout 2010, with a high of approximately $1.01 in December 2010 and a low of approximately $0.93 in May 2010.

WTI pricing was reflective of the slow overall economic recovery in the United States and Europe, with offsetting strong Asian demand mitigating the decline. The relative weakness of the US dollar also contributed to higher WTI pricing. For 2010, WTI averaged US$79.55 per bbl, an increase of 28% compared to US$61.93 per bbl for 2009 (2008 – US$99.65 per bbl).

Brent averaged US$79.50 per bbl for 2010, an increase of 29% compared to US$61.61 per bbl for 2009 (2008 – US$96.99 per bbl). Crude oil sales contracts for the North Sea and Offshore West Africa are typically based on Brent pricing, which is more reflective of international markets and the overall supply and demand balance. Brent pricing was reflective of continued strong demand from Asian markets. The increase in Brent pricing relative to WTI was due to logistical constraints and high inventory levels of crude at Cushing during portions of 2010.

The WCS Differential averaged 18% of WTI for 2010 compared to 16% for 2009 (2008 – 20%). The widening WCS Differential was partially due to pipeline disruptions in the last half of 2010 that forced the temporary shutdown and apportionment of major oil pipelines to Midwest refineries in the United States.

The Company anticipates continued volatility in the crude oil pricing benchmarks due to the unpredictable nature of supply and demand factors, geopolitical events and the timing and extent of the continuing economic recovery. The Heavy Differential is expected to continue to reflect seasonal demand fluctuations and refinery margins.

NYMEX natural gas prices averaged US$4.42 per MMBtu for 2010, an increase of 10% from US$4.03 per MMBtu for 2009 (2008 – US$8.95 per MMBtu). Alberta based AECO natural gas pricing for 2010 averaged $3.91 per GJ and was comparable to average prices in 2009 (2008 – $7.71 per GJ). Natural gas prices continue to be depressed due to strong US shale gas production limiting the upside to natural gas price recovery.

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Operating, Royalty and Capital Costs

Strong commodity prices in recent years have resulted in increased demand for oilfield services worldwide. This has led to inflationary operating and capital cost pressures throughout the crude oil and natural gas industry, particularly related to drilling activities and oil sands developments.

In Canada, the Federal Government has indicated its intent to develop regulations that would be in effect in the near term to address industrial GHG emissions, as part of the national GHG reduction target. The Federal Government will also be developing a comprehensive management system for air pollutants. In the province of Alberta, GHG regulations came into effect July 1, 2008, affecting facilities emitting more than 100 kilotonnes of CO2e annually. Two of the Company's facilities, the Primrose/Wolf Lake in situ heavy crude oil facilities and the Hays sour natural gas plant, face compliance obligations under the regulations. In the province of British Columbia, carbon tax is currently being assessed at $20/tonne of CO2e on fuel consumed and gas flared in the province. This rate is scheduled to increase to $25/tonne on July 1, 2011, and to $30/tonne by July 1, 2012. As part of its involvement with the Western Climate Initiative, British Columbia has also announced that certain upstream oil and gas facilities will be included in a regional cap and trade system beginning in 2012. It is estimated that eight facilities in British Columbia will be included under the cap and trade system, based on a proposed requirement of 25 kilotonne CO2e annually. The province of Saskatchewan is expected to release GHG regulations in 2011 that would likely require the North Tangleflags in situ heavy oil facility to meet a reduction target for its GHG emissions. In the UK, GHG regulations have been in effect since 2005. In Phase 1 (2005 – 2008) of the UK National Allocation Plan, the Company operated below its CO2 allocation. In Phase 2 (2009 – 2012) the Company's CO2 allocation has been decreased below the Company's estimated current operations emissions. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO2 emissions at its major facilities and on trading mechanisms to ensure compliance with requirements now in effect.

Legislation to regulate GHGs in the United States through a cap and trade system is pending. In the absence of legislation, the United States Environmental Protection Agency ("EPA") is intending to regulate GHGs under the Clean Air Act. This EPA action would be subject to legal and political challenges. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the United States. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oil with higher emissions intensity.

Continued cost pressures and the final outcome of changes to environmental regulations may adversely impact the Company's future net earnings, cash flow and capital projects. For additional details, refer to the "Greenhouse Gas and Other Air Emissions" section of this MD&A.

The Alberta Government implemented changes to the Alberta Royalty Framework ("ARF") effective January 1, 2009. The ARF includes a number of changes to royalty rates for natural gas, crude oil, and oil sands production. Under the ARF, royalties payable vary according to commodity prices and the productivity of wells. Initial changes to the Alberta royalty regime under the ARF included the implementation of a sliding scale for oil sands royalties ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout, depending on benchmark crude oil pricing.

During 2010, the Government of Alberta modified crude oil and natural gas royalty rates. These changes included:

§ Effective May 1, 2010, an extension of the period subject to the 5% maximum royalty rate for coalbed methane and shale gas wells to the first 36 months after start of production, subject to volume limits of 750 MMcfe for coalbed methane and no volume limits for shale gas.

- § Effective May 1, 2010, an extension of the period subject to the 5% maximum royalty rate for horizontal natural gas and crude oil wells. The period for horizontal natural gas wells has been extended to the first 18 months after start of production, and volumes of 500 MMcfe. Limits on production months and volumes for crude oil will be set according to the measured depth of the wells.

- § Effective January 1, 2011, a reduction in the maximum royalty rate to 5% on new natural gas and crude oil wells for the first 12 months after the start of production, subject to volume limits of 500 MMcfe and 50,000 BOE respectively.

- § Effective January 1, 2011, a reduction in the maximum royalty rate for crude oil from 50% to 40% and a reduction in the maximum royalty rate for conventional and unconventional natural gas from 50% to 36%.

Modifications were also made to the natural gas deep drilling program, including changes to depth requirements. The Government of Alberta also announced changes to the price components of oil and gas royalty formulas to reduce the royalty rate at prices higher than $85.00 per bbl and $5.25 per GJ respectively.

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ANALYSIS OF CHANGES IN REVENUE, BEFORE ROYALTIES AND RISK MANAGEMENT ACTIVITIES

		Changes due to				Changes due to			
($ millions)	2008	Volumes	Prices	Other	2009	Volumes	Prices	Other	2010
North America									
Crude oil and NGLs	$ 8,811	$ (424)	$(2 ,649)	$ –	$ 5,738	$ 938	$ 1,127	$ 2	$ 7,805
Natural Gas	4,685	(598)	(1,852)	–	2,235	(121)	(206)	–	1,908
	13,496	(1,022)	(4,501)	–	7,973	817	921	2	9,713
North Sea									
Crude oil and NGLs	1,753	(344)	(465)	–	944	(71)	171	(1)	1,043
Natural gas	16	–	1	–	17	–	(2)	–	15
	1,769	(344)	(464)	–	961	(71)	169	(1)	1,058
Offshore West Africa									
Crude oil and NGLs	895	413	(436)	–	872	(130)	104	–	846
Natural gas	49	18	(26)	–	41	(6)	3	–	38
	944	431	(462)	–	913	(136)	107	–	884
Subtotal									
Crude oil and NGLs	11,459	(355)	(3,550)	–	7,554	737	1,402	1	9,694
Natural gas	4,750	(580)	(1,877)	–	2,293	(127)	(205)	–	1,961
	16,209	(935)	(5,427)	–	9,847	610	1,197	1	11,655
Oil Sands Mining and Upgrading	–	1,253	–	–	1,253	1,175	221	–	2,649
Midstream	77	–	–	(5)	72	–	–	7	79
Intersegment eliminations and other (1)	(113)	–	–	19	(94)	–	–	33	(61)
Total	$ 16,173	$ 318	$ (5,427)	$ 14	$ 11,078	$ 1,785	$ 1,418	$ 41	$ 14,322

(1) Eliminates internal transportation, electricity charges, and natural gas sales.

Revenue increased 29% to $14,322 million for 2010 from $11,078 million for 2009 (2008 – $16,173 million). The increase was primarily due to an increase in realized crude oil and NGL prices and volumes, partially offset by a decrease in realized natural gas prices and volumes.

For 2010, 13% of the Company’s crude oil and natural gas revenue was generated outside of North America (2009 – 17%; 2008 – 17%). North Sea accounted for 7% of crude oil and natural gas revenue for 2010 (2009 – 9%; 2008 – 11%), and Offshore West Africa accounted for 6% of crude oil and natural gas revenue for 2010 (2009 – 8%; 2008 – 6%).

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ANALYSIS OF DAILY PRODUCTION, BEFORE ROYALTIES

	2010	2009	2008
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	270,562	234,523	243,826
North America – Oil Sands Mining and Upgrading	90,867	50,250	–
North Sea	33,292	37,761	45,274
Offshore West Africa	30,264	32,929	26,567
	424,985	355,463	315,667
Natural gas (MMcf/d)			
North America	1,217	1,287	1,472
North Sea	10	10	10
Offshore West Africa	16	18	13
	1,243	1,315	1,495
Total barrels of oil equivalent (BOE/d)	632,191	574,730	564,845
Product mix			
Light and medium crude oil and NGLs	18%	21%	22%
Pelican Lake heavy crude oil	6%	6%	6%
Primary heavy crude oil	15%	15%	16%
Bitumen (thermal oil)	14%	11%	12%
Synthetic crude oil	14%	9%	–
Natural gas	33%	38%	44%
Percentage of gross revenue (1)			
(excluding midstream revenue)			
Crude oil and NGLs	85%	78%	68%
Natural gas	15%	22%	32%

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

ANALYSIS OF DAILY PRODUCTION, NET OF ROYALTIES

	2010	2009	2008
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	219,736	201,873	207,933
North America – Oil Sands Mining and Upgrading	87,763	48,833	–
North Sea	33,227	37,683	45,182
Offshore West Africa	28,288	29,922	22,641
	369,014	318,311	275,756
Natural gas (MMcf/d)			
North America	1,168	1,214	1,225
North Sea	10	10	10
Offshore West Africa	15	17	11
	1,193	1,241	1,246
Total barrels of oil equivalent (BOE/d)	567,743	525,103	483,541

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 and medium crude oil and NGLs, Pelican Lake heavy crude oil, primary heavy crude oil, bitumen (thermal oil), and SCO.

Total production averaged 632,191 BOE/d for 2010, a 10% increase from 574,730 BOE/d for 2009 (2008 – 564,845 BOE/d).

Total production of crude oil and NGLs before royalties increased 20% to 424,985 bbl/d for 2010 from 355,463 bbl/d for 2009 (2008 – 315,667 bbl/d). The increase in crude oil and NGLs production from 2009 was primarily due to higher volumes from the Company’s bitumen (thermal oil) and Horizon operations. Crude oil and NGLs production for 2010 was within the Company’s previously issued guidance of 423,000 to 430,000 bbl/d.

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Natural gas production continued to represent the Company's largest product offering, accounting for 33% of the Company's total production in 2010. Total natural gas production before royalties decreased 5% to 1,243 MMcf/d for 2010 from 1,315 MMcf/d for 2009 (2008 – 1,495 MMcf/d). The decrease in natural gas production from 2009 primarily reflected natural production declines due to the Company's strategic decision to reduce natural gas drilling activity to focus on higher return crude oil projects, partially offset by new production volumes from the Septimus facility in Northeast British Columbia and natural gas producing properties acquired during the year. Natural gas production for 2010 was within the Company's previously issued guidance of 1,242 to 1,250 MMcf/d.

For 2011, annual production is forecasted to average between 385,000 and 427,000 bbl/d of crude oil and NGLs and between 1,177 and 1,246 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for 2010 increased 15% to average 270,562 bbl/d from 234,523 bbl/d for 2009 (2008 – 243,826 bbl/d). The increase in production from 2009 was primarily due to the cyclic nature of the Company's bitumen (thermal oil) production and the results of the impact of a record heavy oil drilling program.

North America natural gas production for 2010 decreased 5% to average 1,217 MMcf/d from 1,287 MMcf/d for 2009 (2008 –1,472 MMcf/d). The decrease in natural gas production from 2009 reflected production declines due to the Company's strategic decision to reduce natural gas drilling activity to focus on higher return crude oil projects, partially offset by results of new production from the Septimus facility in Northeast British Columbia and natural gas producing properties acquired during the year.

North America – Oil Sands Mining and Upgrading

Horizon Phase 1 commenced production of synthetic crude oil during 2009. Production averaged 90,867 bbl/d for 2010, an increase of 81% from 50,250 bbl/d for 2009. The increase in production of synthetic crude oil from 2009 reflected the Company's focus on reliability improvements and ramping up of production.

North Sea

North Sea crude oil production for 2010 was 33,292 bbl/d, a decrease of 12% from 37,761 bbl/d for 2009 (2008 – 45,274 bbl/d). The decrease in production volumes from 2009 was due to natural field declines and timing of scheduled maintenance shut downs in 2010.

Offshore West Africa

Offshore West Africa crude oil production for 2010 decreased 8% to 30,264 bbl/d from 32,929 bbl/d for 2009 (2008 – 26,567 bbl/d), due to natural field declines.

Performance from the Olowi Field continues to be below expectations and, as a result, the Company recognized a pre-tax ceiling test impairment of $726 million ($672 million after-tax) at December 31, 2010.

CRUDE OIL INVENTORY VOLUMES

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. Revenue has not been recognized on crude oil volumes that were stored in various tanks, pipelines, or floating production, storage and offloading vessels as follows:

(bbl)	2010	2009	2008
North America – Exploration and Production	761,351	1,131,372	761,351
North America – Oil Sands Mining and Upgrading (SCO)	1,172,200	1,224,481	–

North Sea	264,995	713,112	558,904
Offshore West Africa	404,197	51,103	1,113,156
	2,602,743	3,120,068	2,433,411

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OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

		2010		2009		2008
Crude oil and NGLs ($/bbl) (1)						
Sales price (2)	$	65.81	$	57.68	$	82.41
Royalties		10.09		6.73		10.48
Production expense		14.16		15.92		16.26
Netback	$	41.56	$	35.03	$	55.67
Natural gas ($/Mcf) (1)						
Sales price (2)	$	4.08	$	4.53	$	8.39
Royalties (3)		0.20		0.32		1.46
Production expense		1.09		1.08		1.02
Netback	$	2.79	$	3.13	$	5.91
Barrels of oil equivalent ($/BOE) (1)						
Sales price (2)	$	49.90	$	44.87	$	68.62
Royalties		6.72		4.72		9.78
Production expense		11.25		11.98		11.79
Netback	$	31.93	$	28.17	$	47.05

(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) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts

ANALYSIS OF PRODUCT PRICES – EXPLORATION AND PRODUCTION

		2010		2009		2008
Crude oil and NGLs ($/bbl) (1) (2)						
North America	$	62.28	$	54.70	$	77.42
North Sea	$	82.49	$	68.84	$	100.31
Offshore West Africa	$	78.93	$	65.27	$	97.96
Company average	$	65.81	$	57.68	$	82.41
Natural gas ($/Mcf) (1) (2)						
North America	$	4.05	$	4.51	$	8.41
North Sea	$	3.83	$	4.66	$	4.09
Offshore West Africa	$	6.63	$	6.11	$	10.03
Company average	$	4.08	$	4.53	$	8.39
Company average ($/BOE) (1) (2)	$	49.90	$	44.87	$	68.62

(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.

Realized crude oil and NGLs prices increased 14% to average $65.81 per bbl for 2010 from $57.68 per bbl for 2009 (2008 – $82.41 per bbl). The increase in 2010 was primarily a result of higher WTI and Brent benchmark crude oil prices during the year, partially offset by the impact of a widening WCS Differential and the stronger Canadian dollar relative to the US dollar during 2010.

The Company's realized natural gas price decreased 10% to average $4.08 per Mcf for 2010 from $4.53 per Mcf for 2009 (2008 – $8.39 per Mcf). The decrease in 2010 was primarily due to lower benchmark prices resulting from lower demand and high storage levels, strong incremental production from shale gas plays, the widening NYMEX and AECO differential and the impact of a stronger Canadian dollar relative to the US dollar.

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North America

North America realized crude oil prices increased 14% to average $62.28 per bbl for 2010 from $54.70 per bbl for 2009 (2008 – $77.42 per bbl). The increase in 2010 was primarily due to higher WTI benchmark pricing, partially offset by the impact of the widening WCS Differential and the stronger Canadian dollar relative to the US dollar.

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 2010, the Company contributed approximately 165,000 bbl/d of heavy crude oil blends to the WCS stream. The Company has entered into a 20 year transportation agreement to commit to ship 120,000 bbl/d of heavy sour crude oil blend on the proposed 500,000 bbl/d Keystone Pipeline US Gulf Coast expansion from Hardisty, Alberta to the US Gulf Coast. Contemporaneously, the Company also entered into a 20 year crude oil purchase and sales agreement to sell 100,000 bbl/d of heavy sour crude oil to a major US refiner. Deliveries under the agreements are expected to commence in 2013 upon completion of the pipeline expansion and are subject to receipt of regulatory approval of the pipeline expansion.

Subsequent to December 31, 2010, the Company announced that it had entered into a partnership agreement with North West Upgrading Inc. to move forward with detailed engineering regarding the construction and operation of a bitumen refinery near Redwater, Alberta. In addition, the partnership has entered into an agreement to process bitumen supplied by the Government of Alberta under the Alberta Royalty Framework's Bitumen Royalty In Kind initiative. Project development is dependent upon completion of this detailed engineering and final project sanction by the respective parties.

North America realized natural gas prices decreased 10% to average $4.05 per Mcf for 2010 from $4.51 per Mcf for 2009 (2008 – $8.41 per Mcf), primarily related to lower benchmark prices due to lower demand and high storage levels, the widening NYMEX and AECO differential, strong incremental production from shale gas plays, the impact of natural gas physical sales contracts in 2009 and the impact of a stronger Canadian dollar relative to the US dollar.

Comparisons of the prices received in North America Exploration and Production by product type were as follows:

(Yearly average)		2010		2009		2008
Wellhead Price (1) (2)						
Light and medium crude oil and NGLs (C$/bbl)	$	68.02	$	57.02	$	89.04
Pelican Lake heavy crude oil (C$/bbl)	$	61.69	$	55.52	$	76.91
Primary heavy crude oil (C$/bbl)	$	62.04	$	55.66	$	74.91
Bitumen (thermal oil) (C$/bbl)	$	59.55	$	51.18	$	71.89
Natural gas (C$/Mcf)	$	4.05	$	4.51	$	8.41

(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 Sea

North Sea realized crude oil prices increased 20% to average $82.49 per bbl for 2010 from $68.84 per bbl for 2009 (2008 – $100.31 per bbl). Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices at the time of lifting. The increase in realized crude oil prices in the North Sea from 2009 reflected increased Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 21% to average $78.93 per bbl for 2010 from $65.27 per bbl for 2009 (2008 – $97.96 per bbl). Realized crude oil prices per bbl in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices at the time of lifting. The increase in realized crude oil prices in Offshore West Africa from 2009 reflected increased Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

		2010		2009		2008
Crude oil and NGLs ($/bbl) (1)						
North America	$	11.85	$	7.93	$	11.99
North Sea	$	0.16	$	0.14	$	0.21
Offshore West Africa	$	5.54	$	5.79	$	14.81
Company average	$	10.09	$	6.73	$	10.48
Natural gas ($/Mcf) (1)						
North America (2)	$	0.20	$	0.32	$	1.47
Offshore West Africa	$	0.53	$	0.53	$	1.52
Company average	$	0.20	$	0.32	$	1.46
Company average ($/BOE) (1)	$	6.72	$	4.72	$	9.78
Percentage of revenue (3)						
Crude oil and NGLs		15%		12%		13%
Natural gas (2)		5%		7%		17%
BOE		13%		11%		14%

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

(2) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

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

North America

Government royalties on a significant portion of North America crude oil and NGLs production fall under the oil sands royalty regime and are calculated on a project by project basis as a percentage of gross revenue less operating, capital and abandonment costs (“net profit”). For 2008 and prior years, royalties were calculated as 1% of gross revenues until the Company’s capital investments in the applicable project were fully recovered, at which time the royalty increased to 25% of net profit. Effective January 1, 2009, changes to the Alberta royalty regime under the ARF include the implementation of a sliding scale for oil sands royalties ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout depending on benchmark crude oil pricing.

Crude oil and NGLs royalties for 2010 compared to 2009 reflected higher realized crude oil prices and averaged approximately 19% of gross revenues for 2010 compared to 14% for 2009 (2008 – 15%). North America crude oil and NGLs royalties per bbl are anticipated to average 16% to 20% of gross revenue for 2011.

Natural gas royalties averaged approximately 5% of gross revenues for 2010 compared to 7% for 2009 (2008 – 18%), primarily due to lower benchmark natural gas prices. North America natural gas royalties per Mcf are anticipated to average 4% to 6% of gross revenue for 2011.

North Sea

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

Offshore West Africa

Under the terms of the Production Sharing Contracts ("PSCs"), royalty rates fluctuate based on realized commodity pricing, capital costs, and the timing of liftings from each field. Royalty rates as a percentage of revenue averaged approximately 7% for 2010 compared to 9% for 2009 (2008 – 15%). Offshore West Africa royalty rates are anticipated to average 13% to 15% of gross revenue for 2011, as a result of the expected payout of the Baobab Field.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

		2010		2009		2008
Crude oil and NGLs ($/bbl) (1)						
North America	$	12.14	$	14.63	$	14.96
North Sea	$	29.73	$	26.98	$	26.29
Offshore West Africa	$	14.64	$	12.83	$	10.29
Company average	$	14.16	$	15.92	$	16.26
Natural gas ($/Mcf) (1)						
North America	$	1.06	$	1.07	$	1.00
North Sea	$	2.91	$	2.16	$	2.51
Offshore West Africa	$	1.76	$	1.23	$	1.61
Company average	$	1.09	$	1.08	$	1.02
Company average ($/BOE) (1)	$	11.25	$	11.98	$	11.79

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

North America

North America crude oil and NGLs production expense for 2010 decreased 17% to $12.14 per bbl from $14.63 per bbl for 2009 (2008 – $14.96 per bbl). The decrease in production expense per bbl from 2009 was primarily a result of higher production volumes and lower cost of natural gas for fuel for the Company's bitumen (thermal oil) operations.

North America natural gas production expense for 2010 was $1.06 per Mcf, comparable to 2009 production expense at $1.07 per Mcf (2008 – $1.00 per Mcf), as lower service costs offset the effects of lower production volumes.

North Sea

North Sea crude oil production expense for 2010 increased 10% to $29.73 per bbl from $26.98 per bbl for 2009 (2008 - $26.29 per bbl). Production expense increased on a per barrel basis due to lower volumes on relatively fixed costs.

Offshore West Africa

Offshore West Africa crude oil production expense for 2010 increased 14% to $14.64 per bbl from $12.83 per bbl for 2009 (2008 - $10.29 per bbl). Production expense increased on a per barrel basis due to the timing of liftings for each field, including the impact of costs associated with the Olowi Field which has higher production expenses than the Espoir and Baobab fields.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts) (1)		2010		2009		2008
North America	$	2,336	$	2,060	$	2,236
North Sea		303		261		317
Offshore West Africa		1,023		335		132
Expense	$	3,662	$	2,656	$	2,685
$/BOE	$	18.49	$	13.82	$	12.97

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

Depletion, Depreciation and Amortization (“DD&A”) expense for 2010 increased to $3,662 million from $2,656 million for 2009 (2008 – $2,685 million), primarily due to higher production in North America, an increase in the estimated future costs to develop the Company’s proved undeveloped reserves in the North Sea and the impact of a ceiling test impairment related to Gabon, Offshore West Africa at December 31, 2010.

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ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts) (1)		2010		2009		2008
North America	$	46	$	41	$	42
North Sea		33		24		27
Offshore West Africa		6		4		2
Expense	$	85	$	69	$	71
$/BOE	$	0.43	$	0.36	$	0.34

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

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time. Accretion expense for 2010 increased from 2009 primarily due to higher asset retirement obligations recognized in the North Sea in 2009.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

FINANCIAL METRICS

($/bbl) (1)		2010		2009		2008
SCO sales price (2)	$	77.89	$	70.83	$	–
Bitumen value for royalty purposes (3)	$	56.14	$	56.57	$	–
Bitumen royalties (4)	$	2.72	$	2.15	$	–

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

(2) Net of transportation.

(3) Calculated as the simple average of the monthly bitumen valuation methodology price.

(4) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

Realized SCO sales prices increased 10% to average $77.89 per bbl for the year ended December 31, 2010 from $70.83 per bbl for the year ended December 31, 2009. The increase in SCO prices from 2009 was primarily due to the increase in the WTI benchmark price, offset by the impact of the strengthening Canadian dollar. There is an active market for SCO throughout North America.

PRODUCTION COSTS

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 15 to the Company’s consolidated financial statements.

($ millions)		2010		2009		2008
Cash costs, excluding natural gas costs	$	1,082	$	599	$	–
Natural gas costs		126		84		–
Total cash production costs	$	1,208	$	683	$	–

($/bbl) (1)	2010	2009	2008

Cash costs, excluding natural gas costs	$	32.58	$	34.97	$	–
Natural gas costs		3.78		4.92		–
Total cash production costs	$	36.36	$	39.89	$	–
Sales (bbl/d)		91,010		46,896		–

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

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First sales from Horizon occurred in the second quarter of 2009.

Total cash production costs averaged $36.36 per bbl for 2010 compared to $39.89 per bbl for 2009. The decrease in cash production costs was primarily due to the Company's ongoing focus on planned maintenance, reliability improvements and the stabilization of production volumes at levels approaching plant capacity.

($ millions)		2010		2009		2008
Depreciation, depletion and amortization	$	366	$	187	$	–
Asset retirement obligation accretion		22		21		–
Total	$	388	$	208	$	–

($/bbl) (1)		2010		2009		2008
Depreciation, depletion and amortization	$	11.02	$	10.95	$	–
Asset retirement obligation accretion		0.67		1.22		–
Total	$	11.69	$	12.17	$	–

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

During 2009, Horizon Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs ceased, and depletion, depreciation and amortization of these assets commenced. Depletion, depreciation and amortization increased in 2010 compared to 2009 primarily due to higher sales volumes and the impact of certain assets depreciated on a straight-line basis.

On January 6, 2011, the Company suspended synthetic crude oil production at its Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. Production will recommence once plant operating capacity is restored and all necessary regulatory and operating approvals are received.

MIDSTREAM

($ millions)		2010		2009		2008
Revenue	$	79	$	72	$	77
Production expense		22		19		25
Midstream cash flow		57		53		52
Depreciation		8		9		8
Segment earnings before taxes	$	49	$	44	$	44

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.

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts) (1)		2010		2009		2008
Expense	$	210	$	181	$	180
$/BOE	$	0.91	$	0.87	$	0.87

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

Administration expense for 2010 increased from 2009 due to higher staffing and general corporate costs.

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STOCK-BASED COMPENSATION

($ millions)		2010		2009		2008
Expense (recovery)	$	294	$	355	$	(52)

The Company's Stock Option Plan (the "Option Plan") was designed to provide current employees with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. As a result of enacted changes to Canadian income tax legislation in 2010 related to the cash surrender of options, the Company anticipates that Canadian based employees will now choose to exercise their options to receive newly issued common shares rather than surrender their options for cash payment.

The Company recorded a $294 million stock-based compensation expense during 2010 primarily as a result of normal course graded vesting of options granted in prior periods, the impact of vested options exercised or surrendered during the year, and the 17% increase in the Company's share price for the year ended December 31, 2010 (December 31, 2010 – $44.35; December 31, 2009 – $38.00; December 31, 2008 – $24.38; December 31, 2007 – $36.29). The Company records a liability for potential cash payments to settle its outstanding employee stock options each reporting period 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. For the year ended December 31, 2010, the Company capitalized $24 million in stock-based compensation to Oil Sands Mining and Upgrading (2009 – $2 million capitalized; 2008 – $23 million recovery).

The stock-based compensation liability at December 31, 2010 reflected the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price. In periods when substantial stock 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.

For the year ended December 31, 2010, the Company paid $45 million for stock options surrendered for cash settlement (2009 – $94 million; 2008 – $207 million).

INTEREST EXPENSE

($ millions, except per BOE amounts and interest rates) (1)		2010		2009		2008
Expense, gross	$	477	$	516	$	609
Less: capitalized interest, Oil Sands Mining and Upgrading		28		106		481
Expense, net	$	449	$	410	$	128
$/BOE	$	1.94	$	1.96	$	0.62
Average effective interest rate		5.0%		4.3%		5.1%

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

Gross interest expense for 2010 decreased from 2009 due to lower debt levels and the impact of a stronger Canadian dollar on US dollar denominated debt partially offset by the impact of higher variable interest rates. The Company's average effective interest rate increased from 2009 primarily due to an increased weighting of fixed versus floating rate debt and higher variable interest rates.

During 2009, interest capitalization ceased on Horizon Phase 1 as the Phase 1 assets were completed and available for their intended use, increasing net interest expense accordingly.

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RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These derivative financial instruments are not intended for trading or speculative purposes.

($ millions)		2010		2009		2008
Crude oil and NGLs financial instruments	$	84	$	(1,330)	$	2,020
Natural gas financial instruments		(234)		(33)		(21)
Foreign currency contracts and interest rate swaps		54		110		(139)
Realized (gain) loss	$	(96)	$	(1,253)	$	1,860
Crude oil and NGLs financial instruments	$	(108)	$	2,039	$	(3,104)
Natural gas financial instruments		71		(58)		16
Foreign currency contracts and interest rate swaps		12		10		(2)
Unrealized (gain) loss	$	(25)	$	1,991	$	(3,090)
Net (gain) loss	$	(121)	$	738	$	(1,230)

Complete details related to outstanding derivative financial instruments at December 31, 2010 are disclosed in note 12 to the Company's consolidated financial statements.

The cash settlement amount of commodity derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement, as compared to their mark-to-market value at December 31, 2010.

Due to changes in crude oil and natural gas forward pricing and the reversal of prior period unrealized gains and losses, the Company recorded a net unrealized gain of $25 million ($16 million after-tax) on its risk management activities for the year ended December 31, 2010 (2009 – $1,991 million unrealized loss, $1,437 million after-tax; 2008 – $3,090 million unrealized gain, $2,112 million after-tax).

FOREIGN EXCHANGE

($ millions)		2010		2009		2008
Net realized (gain) loss	$	(2)	$	30	$	(114)
Net unrealized (gain) loss (1)		(180)		(661)		832
Net (gain) loss	$	(182)	$	(631)	$	718

(1) Amounts are reported net of the hedging effect of cross currency swap hedges.

As a result of foreign currency translation, the Company's operating results are affected by the fluctuations in the exchange rates between the Canadian dollar, US dollar, and UK pound sterling. The 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 results in increased revenue from the sale of the Company's production. Production expenses and future income tax liabilities in the North Sea are subject to foreign currency fluctuations due to changes in the exchange rate of the UK pound sterling to the US dollar. 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 net unrealized foreign exchange gain in 2010 was primarily related to the strengthening Canadian dollar in relation to the US dollar with respect to the US dollar denominated debt, together with the impact of the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling. Included in the net unrealized gain for the year ended December 31, 2010 was an unrealized loss of $101 million (2009 – $338 million unrealized loss, 2008 – $449 million unrealized gain) related to the impact of cross currency swap hedges. The net realized foreign exchange gain for 2010 was primarily due to the result of foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The Canadian dollar ended the year at US$1.0054 compared to US$0.9555 at December 31, 2009 (December 31, 2008 – US$0.8166).

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TAXES

($ millions, except income tax rates)		2010		2009		2008
Current	$	91	$	91	$	245
Deferred		28		15		(67)
Taxes other than income tax	$	119	$	106	$	178
North America (1)	$	432	$	28	$	33
North Sea		203		278		340
Offshore West Africa		63		82		128
Current income tax		698		388		501
Future income tax		364		(99)		1,607
		1,062		289		2,108
Income tax rate and other legislative changes (2) (3) (4)		(83)		19		41
	$	979	$	308	$	2,149
Effective income tax rate before income tax rate and other legislative changes		28.1%		24.3%		27.8%

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.

(2) During 2010, future income tax expense included a charge of $83 million related to enacted changes to the taxation of stock options surrendered by employees in Canada for cash.

(3) Includes the effects of one time recoveries of $19 million due to British Columbia corporate income tax rate reductions enacted during 2009.

(4) Includes the effects of one time recoveries of $19 million due to British Columbia corporate income tax rate reductions and $22 million due to Côte d'Ivoire corporate income tax rate reductions enacted during 2008.

Taxes other than income tax primarily includes current and deferred PRT, which is charged on certain fields in the North Sea at the rate of 50% of net operating income, after allowing for certain deductions including related capital and abandonment expenditures.

Taxable income from the Exploration and Production business in Canada is primarily generated through partnerships, with the related income taxes payable in subsequent periods. North America current income taxes have been provided on the basis of this corporate structure. In addition, current income taxes in each business segment will vary depending on available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

The Company is subject to income tax reassessments arising in the normal course. The Company does not believe that any liabilities that may ultimately arise from these reassessments will be material.

For 2011, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense of $350 million to $450 million in Canada and $280 million to $320 million in the North Sea and Offshore West Africa.

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NET CAPITAL EXPENDITURES (1)

($ millions)	2010	2009	2008
Expenditures on property, plant and equipment			
Net property acquisitions	$ 1,904	$ 6	$ 336
Land acquisition and retention	141	77	86
Seismic evaluations	100	73	107
Well drilling, completion and equipping	1,500	1,244	1,664
Production and related facilities	1,122	977	1,282
Total net reserve replacement expenditures	4,767	2,377	3,475
Oil Sands Mining and Upgrading:			
Horizon Phase 1 construction costs	–	69	2,732
Horizon Phase 1 commissioning costs and other	–	202	364
Horizon Phases 2/3 construction costs	319	104	336
Capitalized interest, stock-based compensation and other	88	98	480
Sustaining capital	128	80	–
Total Oil Sands Mining and Upgrading (2)	535	553	3,912
Midstream	7	6	9
Abandonments (3)	179	48	38
Head office	18	13	17
Total net capital expenditures	$ 5,506	$ 2,997	$ 7,451
By segment			
North America	$ 4,369	$ 1,663	$ 2,344
North Sea	149	168	319
Offshore West Africa	246	544	811
Other	3	2	1
Oil Sands Mining and Upgrading	535	553	3,912
Midstream	7	6	9
Abandonments (3)	179	48	38
Head office	18	13	17
Total	$ 5,506	$ 2,997	$ 7,451

(1) Net capital expenditures exclude adjustments related to differences between carrying value and tax value, and other fair value adjustments.

(2) Net expenditures for the Oil Sands Mining and Upgrading assets also include the impact of intersegment eliminations.

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

The Company's operating 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 for 2010 were $5,506 million compared to $2,997 million for 2009 (2008 – $7,451 million). The increase in capital expenditures from the prior year was primarily due to the purchase of crude oil and natural gas producing properties and unproved land in the Company's core regions in Western Canada and the increase in the Company's abandonment program.

Drilling Activity (number of wells)

	2010	2009	2008
Net successful natural gas wells	92	109	269
Net successful crude oil wells	934	644	682
Dry wells	33	46	39
Stratigraphic test / service wells	491	329	131
Total	1,550	1,128	1,121
Success rate (excluding stratigraphic test / service wells)	97%	94%	96%

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North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 83% of the total capital expenditures for the year ended December 31, 2010 compared to approximately 58% for 2009 (2008 – 32%).

During 2010, the Company targeted 98 net natural gas wells, including 26 wells in Northeast British Columbia, 21 wells in the Northern Plains region, 46 wells in Northwest Alberta, and 5 wells in the Southern Plains region. The Company also targeted 953 net crude oil wells during the year. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 654 primary heavy crude oil wells, 175 Pelican Lake heavy crude oil wells, 17 bitumen (thermal oil) wells and 15 light crude oil wells were drilled. Another 92 wells targeting light crude oil were drilled outside the Northern Plains region.

The Company continued to access its large crude oil drilling inventory to maximize value in both the short and long term. Due to the Company's focus on drilling crude oil wells in recent years, a low natural gas price, and as a result of royalty changes under the ARF, natural gas drilling activities have been reduced. Deferred natural gas well locations have been retained in the Company's prospect inventory.

As part of the phased expansion of its In situ Oil Sands Assets, the Company is continuing to develop its Primrose thermal projects. During 2010, the Company drilled 17 thermal oil wells, and 58 stratigraphic test wells and observation wells. Overall Primrose thermal production for 2010 was approximately 90,000 bbl/d (2009 – 64,000 bbl/d; 2008 – 65,000 bbl/d). The Primrose East Expansion was completed and first steaming commenced in September 2008, with first production achieved in the first quarter of 2009. During 2009, operational issues on one of the pads caused steaming to cease on all well pads in the Primrose East project area. The Company received approval from regulators to commence steaming on the next cycle in the third quarter of 2010.

The next planned phase of the Company's In Situ Oil Sands Assets expansion is the Kirby Project. Currently the Company is proceeding with the detailed engineering and design work. During the third quarter of 2010, the Company received final regulatory approval for Phase 1 of the Project. During the fourth quarter, the Company's Board of Directors sanctioned Kirby Phase 1. Construction commenced in the fourth quarter of 2010, with first steam targeted in 2013.

Development of new pads and tertiary recovery conversion projects at Pelican Lake continued as expected throughout 2010. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 38,000 bbl/d in 2010 (2009 – 37,000 bbl/d; 2008 – 37,000 bbl/d).

For 2011, the Company's overall drilling activity in North America is expected to comprise approximately 72 natural gas wells and 1,186 crude oil wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

Phase 2/3 spending during 2010 continued to be focused on construction of the third Ore Preparation Plant, additional product tankage, the butane treatment unit, the sulphur recovery unit, and hydro-transport.

On January 6, 2011, a fire occurred at the Company's primary upgrading coking plant. The fire was confined to one of the coke drums. Production capacity at Horizon has been suspended during the investigation and repair/rebuild to plant equipment damaged by the fire.

A preliminary assessment of the extent of damage and timelines to repair/rebuild indicate that the coke drums are serviceable. The procurement process for all necessary replacement components and parts for the damage caused by the fire has been initiated. Based on preliminary estimates, the first set of coke drums is targeted to resume production in the second quarter of 2011 with production rates of approximately 55,000 bbl/d. The second set of coke drums is currently targeted to be on production in the third quarter of 2011.

The Company believes that it has adequate insurance coverage to mitigate all significant property damage related losses. The Company also maintains business interruption coverage, subject to a waiting period, which it believes will mitigate operating losses related to on-going operations.

North Sea

During 2010, the Company drilled 0.9 net oil wells and 0.9 net injection wells at Ninian following commencement of drilling in the second quarter of the year. The Company also successfully completed planned maintenance shutdowns at all of its production facilities in the year.

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The Company plans to continue drilling at Ninian during 2011 and commence drilling at Murchison in the second quarter of 2011. The Company also continues to focus on developing and high grading its inventory of drilling locations for future execution.

Offshore West Africa

The Company drilled 7.1 wells during 2010. First crude oil was achieved on the Olowi Field on Platform B in the second quarter of the year, and on Platform A in the fourth quarter of the year. At Espoir, facilities upgrades were competed and incremental production volumes delivered during 2010.

Performance from the Olowi Field continues to be below expectations and, as a result, the Company recognized a pre-tax ceiling test impairment of $726 million ($672 million after-tax) at December 31, 2010.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		2010		2009		2008
Working capital (deficit) (1)	$	(984)	$	(514)	$	392
Long-term debt (2) (3)	$	8,499	$	9,658	$	13,016
Shareholders' equity						
Share capital	$	3,147	$	2,834	$	2,768
Retained earnings		18,005		16,696		15,344
Accumulated other comprehensive (loss) income		(167)		(104)		262
Total	$	20,985	$	19,426	$	18,374
Debt to book capitalization (3) (4)		29%		33%		41%
Debt to market capitalization (3) (5)		15%		19%		33%
After-tax return on average common shareholders' equity (6)		8%		8%		33%
After-tax return on average capital employed (3) (7)		7%		6%		19%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.

(2) Includes the current portion of long-term debt (2010 – $nil; 2009 – $nil; 2008 – $420 million).

(3) Long-term debt at December 31, 2010, 2009 and 2008 is stated at its carrying value, net of fair value adjustments, original issue discounts and transaction costs.

(4) Calculated as current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.

(5) Calculated as current and long-term debt; divided by the market value of common shareholders' equity plus current and long-term debt.

(6) Calculated as net earnings for the year; as a percentage of average common shareholders' equity for the year.

(7) Calculated as net earnings plus after-tax interest expense for the year; as a percentage of average capital employed.

At December 31, 2010, the Company's capital resources consisted primarily of cash flow from operations, available bank 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 bank 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. The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its on-going hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms, will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy.

The Company believes that its capital resources are sufficient to compensate for any short term cash flow reductions arising from Horizon, and accordingly, the Company's targeted capital program currently remains unchanged for 2011. At December 31, 2010, the Company had $2,444 million of available credit under its bank credit facilities. During 2010, the Company repaid $400 million of the medium term notes bearing interest at 5.50%. Long-term debt was $8,499 million at December 31, 2010, resulting in a debt to book capitalization ratio of 29% (December 31, 2009 – 33%; December 31, 2008 – 41%). This ratio is below the 35% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, and lower commodity prices occur. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet and flexible capital structure. Further details related to the Company's long-term debt at December 31, 2010 are discussed below and in note 5 to the Company's consolidated financial statements.

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During 2009, the Company filed new base shelf prospectuses that allowed for the issue of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

The Company’s commodity hedging program reduces the risk of volatility in commodity prices and supports the Company’s cash flow for its capital expenditures programs. This program currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this program, the purchase of put options is in addition to the above parameters. As at December 31, 2010, in accordance with the policy, approximately 11% of budgeted crude oil volumes were hedged using collars for 2011. Further details related to the Company’s commodity related derivative financial instruments outstanding at December 31, 2010 are discussed in note 12 to the Company’s consolidated financial statements.

Share Capital

The Company’s shareholders passed a Special Resolution subdividing the common shares of the Company on a two-for-one basis at the Company’s Annual and Special Meeting held on May 6, 2010, with such subdivision taking effect in May 2010. All common share, per common share, and stock option amounts have been restated to reflect the share split.

As at December 31, 2010, there were 1,090,848,000 common shares outstanding and 66,844,000 stock options outstanding. As at March 1, 2011, the Company had 1,093,711,000 common shares outstanding and 63,029,000 stock options outstanding.

On March 1, 2011, the Company’s Board of Directors approved an increase in the annual dividend declared by the Company to $0.36 per common share for 2011. The increase represents a 20% increase from the prior year, recognizing the stability of the Company’s cash flow and providing a return to Shareholders. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change. In March 2010, an increase in the annual dividend paid by the Company to $0.30 per common share was approved for 2010. The increase represented a 43% increase from 2009.

In 2010, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange (“TSX”) and the New York Stock Exchange (“NYSE”), during the 12-month period commencing April 6, 2010 and ending April 5, 2011, up to 27,163,940 common shares or 2.5% of the common shares of the Company outstanding at March 17, 2010. As at March 1, 2011, 2,000,000 common shares had been purchased for cancellation at an average price of $33.77 per common share, for a total cost of $68 million.

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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. As at December 31, 2010, no entities were consolidated under CICA Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at December 31, 2010:

($ millions)	2011	2012	2013	2014	2015	Thereafter
Product transportation and pipeline	$ 228	$ 199	$ 172	$ 164	$ 152	$ 932
Offshore equipment operating lease	$ 141	$ 98	$ 97	$ 97	$ 81	$ 168
Offshore drilling	$ 7	$ –	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 18	$ 17	$ 19	$ 28	$ 27	$ 7,123
Long-term debt (2)	$ 398	$ 348	$ 798	$ 348	$ 400	$ 4,774
Interest expense (3)	$ 438	$ 400	$ 353	$ 333	$ 307	$ 4,236
Office leases	$ 27	$ 27	$ 28	$ 28	$ 32	$ 339
Other	$ 102	$ 66	$ 19	$ 16	$ 24	$ 10

(1) Amounts represent management's estimate of the future undiscounted payments to settle ARO related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2011 – 2015 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(2) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,436 million of revolving bank credit facilities due to the extendable nature of the facilities.

(3) Interest expense amounts represent the scheduled fixed rate and variable rate cash payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates as of December 31, 2010.

LEGAL PROCEEDINGS

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

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RESERVES

For the year ended December 31, 2010, the Company retained Independent Qualified Reserves Evaluators to evaluate and review all of the Company's proved, as well as proved plus probable crude oil, NGLs and natural gas reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements.

In previous years, the Company had been granted an exemption order from the securities regulators in Canada that allowed substitution of United States SEC requirements for certain NI 51-101 reserves disclosures. This exemption expired on December 31, 2010. As a result, the 2010 reserves disclosure is presented in accordance with Canadian reporting requirements using forecast prices and escalated costs.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States FASB Topic 932 "Extractive Activities - Oil and Gas" in the Company's annual Form 40-F filed with the SEC and in the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

The following tables summarize the Company's gross proved and proved plus probable reserves as at December 31, 2010, prepared in accordance with NI 51-101 reserves disclosures:

Proved Reserves	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2009	501	116	251	732	1,871	3,902	46	4,167
Discoveries	-	1	-	-	-	69	2	15
Extensions	1	20	2	47	-	217	5	111
Infill Drilling	3	25	-	-	-	21	1	33
Improved Recovery	-	-	1	-	-	2	3	4
Acquisitions	12	2	-	109	-	446	7	204
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	1(94)		(1)(16)	
Technical Revisions	-	30	(1)	64	93	153	6	218
Production	(35)	(34)	(14)	(33)	(33)(454)		(6)(231)	
December 31, 2010	482	160	239	919	1,932	4,262	63	4,505

Proved plus Probable Reserves	Light and Medium Crude Oil	Primary Heavy Crude Oil	Pelican Lake Heavy Crude	Bitumen (Thermal Oil)	Synthetic Crude Oil	Natural Gas	Natural Gas Liquids	Barrels of Oil Equivalent

			Oil					
	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(Bcf)	(MMbbl)	(MMBOE)
December 31, 2009	732	155	357	1,327	2,840	5,242	61	6,346
Discoveries	-	1	-	-	-	88	3	19
Extensions	1	28	4	108	-	315	7	200
Infill Drilling	6	35	1	-	-	35	1	49
Improved Recovery	-	-	1	-	-	2	3	4
Acquisitions	16	3	-	272	-	556	8	391
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	-	-	-	-	(2)	(120)	(1)	(23)
Technical Revisions	(17)	29	(1)	28	83	104	7	147
Production	(35)	(34)	(14)	(33)	(33)	(454)	(6)	(231)
December 31, 2010	703	217	348	1,702	2,888	5,767	83	6,902

At December 31, 2010, the Company's gross proved crude oil and NGLs reserves totaled 3,795 MMbbl, and gross proved plus probable crude oil and NGLs reserves totaled 5,941 MMbbl. Proved reserve additions and revisions replaced 279% of 2010 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 241 MMbbl, and additions to proved plus probable reserves amounted to 498 MMbbl. Net positive revisions amounted to 192 MMbbl for proved reserves and 126 MMbbl for proved plus probable reserves. The net gains were primarily due to technical revisions to prior estimates based on improved or better than expected reservoir performance.

At December 31, 2010, the Company's gross proved natural gas reserves totaled 4,262 Bcf, and gross proved plus probable natural gas reserves totaled 5,767 Bcf. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 755 Bcf, and additions to proved plus probable reserves amounted to 996 Bcf. Net positive revisions for proved reserves amounted to 59 Bcf primarily due to technical revisions to prior estimates based on improved or better than expected reservoir performance partially offset by economic factors. Net negative revisions for proved plus probable reserves amounted to 16 Bcf primarily due to lower benchmark natural gas pricing.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of the Company's Independent Qualified Reserves Evaluators 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 reserves.

Information with respect to estimated benchmark future pricing is included in note 4 to the Company's consolidated financial statements. The crude oil, NGL and natural gas reference pricing and inflation and exchange rates used in the preparation of reserves are as per the Sproule price forecast dated December 31, 2010. Additional reserves disclosure is annually disclosed in the AIF and the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

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 into SCO. These inherent risks include, but are not limited to, the following items:

— The ability to find, produce and replace reserves, whether sourced from exploration, improved recovery or acquisitions, 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, ARO and depletion rates;
— Reservoir quality and uncertainty of reserve estimates;
— Prevailing prices of crude oil and NGLs, and natural gas;
— Regulatory risk related to approval for exploration and development activities, which can add to costs or cause delays in projects;
— Labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner;
— Operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas;
— Success of exploration and development activities;
— Timing and success of integrating the business and operations of acquired companies;
— Credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, including derivative financial instruments and physical sales contracts as part of a hedging program;
— Interest rate risk associated with the Company's ability to secure financing on commercially acceptable terms;
— Foreign exchange risk due to fluctuating exchange rates on the Company's US dollar denominated debt and as the majority of sales are based in US dollars;
— Environmental impact risk associated with exploration and development activities, including GHG;
— Mechanical or equipment failure of facilities and infrastructure.
— Risk of catastrophic loss due to fire, explosion or acts of nature;
— Geopolitical risks associated with changing governmental policies, social instability and other political, economic or diplomatic developments in the Company's operations;
— Future legislative and regulatory developments related to environmental regulation;

— Potential actions of governments, regulatory authorities and other stakeholders that may impose operating costs or restrictions in the jurisdictions where the Company has operations;
— Changing royalty regimes;
— Business interruptions because of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting the Company or other parties whose operations or assets directly or indirectly affect the Company and that may or may not be financially recoverable; and
— Other circumstances affecting revenue and expenses.

The Company uses a variety of means to help mitigate and/or minimize these risks. The Company maintains a comprehensive property loss and business interruption insurance program to reduce risk to an acceptable level. Operational control is enhanced by focusing efforts on large core areas with high working interests and by assuming operatorship of key facilities. Product mix is diversified, consisting of the production of natural gas and the production of crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity.

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Accounts receivable from the sale of crude oil and natural gas are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing 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. Substantially all of the Company's accounts receivables are due within normal trade terms. Derivative financial instruments are utilized to help ensure targets are met and to manage commodity prices, foreign currency rates and interest rate exposure. The Company is exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with substantially all investment grade financial institutions and other entities. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions.

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

For additional detail regarding the Company's risks and uncertainties, refer to the Company's AIF.

ENVIRONMENT

The Company continues to invest in people, technologies, facilities and infrastructure to recover and process crude oil and natural gas resources efficiently and in an environmentally sustainable manner.

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 require the Company to address and mitigate the effect of its activities on the environment. 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 environmental 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. Training and due diligence for operators and contractors are key to the effectiveness of the Company's environmental management programs and the prevention of incidents. The Company's environmental risk management strategies employ an Environmental Management Plan (the "Plan"). Details of the Plan, along with performance results, are presented to, and reviewed by, the Board of Directors quarterly.

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

— An internal environmental compliance audit and inspection program of the Company's operating facilities;
— A 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;
— A due diligence program related to groundwater monitoring;
— An active program related to preventing and reclaiming spill sites;
— A solution gas conservation program;
— A program to replace the majority of fresh water for steaming with brackish water;
— Water programs to improve efficiency of use, recycle rates and water storage;

— Environmental planning for all projects to assess impacts and to implement avoidance and mitigation programs;
— Reporting for environmental liabilities;
— A program to optimize efficiencies at the Company's operated facilities;
— Continued evaluation of new technologies to reduce environmental impacts;
— Implementation of a tailings management plan; and
— CO2 reduction programs including the injection of CO2 into tailings and for use in enhanced oil recovery.

For 2010, the Company's capital expenditures included $179 million for abandonment expenditures (2009 – $48 million; 2008 – $38 million).

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The Company's estimated undiscounted ARO at December 31, 2010 was as follows:

Estimated ARO, undiscounted ($ millions)		2010		2009
North America, Exploration and Production	$	4,125	$	3,346
North America, Oil Sands Mining and Upgrading		1,479		1,485
North Sea		1,396		1,522
Offshore West Africa		232		253
		7,232		6,606
North Sea PRT recovery		(423)		(568)
	$	6,809	$	6,038

The estimate of ARO was based on estimates of future costs to abandon and restore 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 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 estimated to result in a PRT recovery of $423 million (2009 – $568 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 undiscounted abandonment liability to $6,809 million (2009 – $6,038 million).

GREENHOUSE GAS AND OTHER AIR EMISSIONS

The Company, through the Canadian Association of Petroleum Producers ("CAPP"), is working with legislators and regulators as they develop and implement new GHG emission laws and regulations. Internally, the Company is pursuing an integrated emissions reduction strategy, to ensure that it is able to comply with existing and future emissions reduction requirements, for both GHGs and air pollutants (such as sulphur dioxide and oxides of nitrogen). The Company continues to develop strategies that will enable it to deal with the risks and opportunities associated with new GHG and air emissions policies. In addition, the Company is working with relevant parties to ensure that new policies encourage technological innovation, energy efficiency, targeted research and development while not impacting competitiveness.

In Canada, the Federal Government has indicated its intent to develop regulations that would be in effect in the near term to address industrial GHG emissions, as part of the national GHG reduction target. The Federal Government will also be developing a comprehensive management system for air pollutants.

In the province of Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO2e annually. Two of the Company's facilities, the Primrose/Wolf Lake in situ heavy crude oil facilities and the Hays sour natural gas plant face compliance obligations under the regulations. In the province of British Columbia, carbon tax is currently being assessed at $20/tonne of CO2e on fuel consumed and gas flared in the province. This rate is scheduled to increase to $25/tonne on July 1, 2011, and to $30/tonne by July 1, 2012. As part of its involvement with the Western Climate Initiative, British Columbia has also announced that certain upstream oil and gas facilities will be included in a regional cap and trade system beginning in 2012. It is estimated that eight facilities in British Columbia will be included under the cap and trade system, based on a proposed requirement of 25 kilotonne CO2e annually. The province of Saskatchewan is expected to release GHG regulations in 2011 that may likely require the North Tangleflags in situ heavy oil facility to meet a reduction target for its GHG emissions. In the UK, GHG regulations have been in effect since 2005. In Phase 1 (2005 – 2007) of the UK National Allocation Plan, the Company operated below its CO2 allocation. In Phase 2 (2008 – 2012) the Company's CO2 allocation has been decreased below the Company's estimated current operations emissions. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO_2 emissions at its major facilities and on trading mechanisms to ensure compliance with requirements now in effect.

Legislation to regulate GHGs in the United States through a cap and trade system is pending. In the absence of legislation, the United States Environmental Protection Agency ("EPA") is intending to regulate GHGs under the Clean Air Act. This EPA action would be subject to legal and political challenges. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the United States. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oil with higher emissions intensity.

There are a number of unresolved issues in relation to Canadian Federal and Provincial GHG regulatory requirements. Key among them is the form of regulation, an appropriate common facility emission level, availability and duration of compliance mechanisms, and resolution of federal/provincial harmonization agreements. The Company continues to pursue GHG emission reduction initiatives including solution gas conservation, compressor optimization to improve fuel gas efficiency, CO_2 capture and sequestration in oil sands tailings, CO_2 capture and storage in association with enhanced oil recovery, and participation in an industry initiative to promote an integrated CO_2 capture and storage network.

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The additional requirements of enacted or proposed GHG regulations on the Company's operations will 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.

Air pollutant standards and guidelines are being developed federally and provincially and the Company is participating in these discussions. Ambient air quality and sector based reductions in air emissions are being reviewed. Through Company and industry participation with stakeholders, guidelines have been developed that adopt a structured process to emission reductions that is commensurate with technological development and operational requirements.

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CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires the Company to make judgments, assumptions and estimates in the application of Canadian GAAP that have a significant impact on the financial results of the Company. Actual results may differ from those estimates, and those differences may be material. Effective January 1, 2011, the Company will adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board. Unless otherwise stated, references to Canadian GAAP do not incorporate the impact of any changes to accounting standards that will be required due to changes required by IFRS. 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.

Exploration and Production Property, Plant and Equipment / Depletion, Depreciation and Amortization

Under Canadian GAAP, the Company follows the full cost method of accounting for its Exploration and Production properties and equipment as prescribed by CICA Accounting Guideline 16 ("AcG 16"). Accordingly, all costs relating to the exploration for and development of 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 a gain or loss except where such dispositions result in a change in the depletion rate of the specific cost centre of 20% or more. Under Canadian GAAP, substantially all of the capitalized costs and estimated 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 prices and costs as required by the SEC for US GAAP purposes.

Under Canadian GAAP, 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 plus probable reserves and estimated future prices and costs, discounted at a risk-free interest rate. At December 31, 2010, a pre-tax ceiling test impairment of $726 million (2009 – $115 million) was recognized under Canadian GAAP related to the Olowi Field in Offshore Gabon. As net revenues exceeded capitalized costs for all other cost centres, no other impairments were required under Canadian GAAP. Under US GAAP, the ceiling test differs from Canadian GAAP in that future net revenues from proved reserves are based on prices and costs using the average first-day-of-the-month price during the previous 12-month period and costs as at the balance sheet date 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 in the current year would not have resulted in the recognition of any incremental after-tax ceiling test impairment (2009 –incremental ceiling test impairment of $815 million) under US GAAP.

The alternate acceptable method of accounting for Exploration and Production 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 estimation of reserves involves the exercise of judgement. Forecasts are based on engineering data, estimated 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 either 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 may also result in an impairment of crude oil and natural gas property, plant and equipment carrying amounts under the ceiling test.

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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 liability associated with the retirement of a tangible long-lived asset is recognized to the extent of a legal obligation resulting from 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.

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 are 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 6.6%. 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 retirement 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 may result in gains or losses on the final settlement of the ARO.

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 between the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted or enacted as of the consolidated balance sheet date. Accounting for income taxes is a complex process that requires management to interpret frequently changing laws and regulations (e.g. changing income tax rates) and make certain judgments with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. These interpretations and judgments impact the current and future income tax provisions, future income tax assets and liabilities, and net earnings.

Risk Management Activities

The Company utilizes various derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company has relied primarily on external readily observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that may be realized or settled in a current market transaction and these differences may be material.

Purchase Price Allocations

The purchase prices 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 internal 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.

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CONTROL ENVIRONMENT

The Company's management, including the President and the Chief Financial Officer and Senior Vice-President, Finance, evaluated the effectiveness of disclosure controls and procedures as at December 31, 2010, 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 the Company's management to allow timely decisions regarding required disclosures.

The Company's management also performed an assessment of internal control over financial reporting as at December 31, 2010, 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 2010 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

While the Company's management believes that the Company's disclosure controls and procedures and internal controls over financial reporting provide a reasonable level of assurance they are effective, they recognize that all control systems have inherent limitations. Because of its inherent limitations, the Company's control systems 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.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, the CICA's Accounting Standards Board confirmed that Canadian publicly accountable enterprises will be required to adopt IFRS as promulgated by the IASB in place of Canadian GAAP effective January 1, 2011.

The Company has established a formal IFRS project governance structure. The structure includes a Steering Committee, which consists of senior levels of management from finance and accounting, operations and information technology ("IT"). The Steering Committee provides regular updates to the Company's Management and the Audit Committee of the Board of Directors.

The Company's IFRS conversion project was broken down into the following phases:

§ Phase 1 Diagnostic – identification of potential accounting and reporting differences between Canadian GAAP and IFRS.

§ Phase 2 Planning – establishment of project governance, processes, resources, budget and timeline.

§ Phase 3 Policy Delivery and Documentation – establishment of accounting policies under IFRS.

§ Phase 4 Policy Implementation – establishment of processes for accounting and reporting, IT change requirements, and education.

§ Phase 5 Sustainment – ongoing compliance with IFRS after implementation.

The Company has substantially completed its IFRS conversion project. Significant differences were identified in accounting for Property, Plant & Equipment ("PP&E"), including exploration costs, depletion and depreciation, capitalized interest, impairment testing, and asset retirement obligations. Other significant differences were noted in accounting for stock-based compensation, risk management activities, and income taxes. A summary of the significant differences identified is included below. As certain IFRS standards may change during 2011, the Company may be required to adopt additional new and /or amended accounting standards in the preparation of its December 31, 2011 consolidated financial statements prepared in accordance with IFRS.

The Company has identified, developed and tested accounting and reporting systems and processes to capture data required for IFRS accounting and reporting, including 2010 requirements to capture both Canadian GAAP and IFRS data. IT system changes are complete and implemented.

Summary of Identified IFRS Accounting Policy Differences

Property, Plant & Equipment

Adoption of IFRS will significantly impact the Company's accounting policies for PP&E. For Canadian GAAP purposes, the Company followed the full cost method of accounting for its Exploration and Production properties and equipment as prescribed by AcG 16. Application of the full cost method of accounting is discussed in the "Critical Accounting Estimates" section of this MD&A. Significant differences in accounting for PP&E under IFRS include:

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§ Pre-exploration costs must be expensed. Under full cost accounting, these costs are currently included in the country cost centre.

§ Exploration and evaluation costs are initially capitalized as exploration and evaluation assets. In areas where the Company has existing operations, costs associated with reserves that are found to be technically feasible and commercially viable will be transferred to PP&E. If technically feasible and commercially viable reserves are not established in an area and if no further activity is planned in that area, the costs are expensed. Under full cost accounting, exploration and evaluation costs are currently disclosed as PP&E but withheld from depletion. Costs are transferred to the depletable assets when proved reserves are assigned or when it is determined that the costs are impaired.

§ PP&E for producing properties is depleted at an asset level. Under full cost accounting, PP&E is depleted on a country cost centre basis.

§ Interest directly attributable to the acquisition or construction of a qualifying asset must be capitalized to the cost of the asset. Under Canadian GAAP, capitalization of interest is not required.

§ Impairment of PP&E is tested at a cash generating unit level (the lowest level at which cash inflows can be separately identified). Under full cost accounting, impairment is tested at the country cost centre level.

IFRS 1 "First-time Adoption of International Financial Reporting Standards" issued by the IASB includes a transition exemption for oil and gas companies following full cost accounting under their previous GAAP. The transition exemption allows full cost companies to allocate their existing full cost PP&E balances using reserve values or volumes to IFRS compliant units of account without requiring retroactive adjustment, subject to an initial impairment test. The Company has adopted this transition exemption. After initial adoption, future impairment charges may be reversed.

Asset Retirement Obligations

Canadian GAAP accounting requirements for asset retirement obligations ("ARO") are discussed in the "Critical Accounting Estimates" section of this MD&A. A significant difference in accounting for ARO under IFRS is that the liability must be re-measured at each balance sheet date using current discount rates, whereas under Canadian GAAP the discount rates do not change once the liability is recorded. On transition to IFRS, the increase in ARO liability on PP&E for which the full cost exemption above is applied must be recorded in retained earnings. For the change in ARO liability on other non-full cost PP&E, the increase is adjusted to PP&E in accordance with the general exemption for decommissioning liabilities included in IFRS 1. In future periods, the impact of changes in discount rates on the ARO liability for all PP&E is adjusted to PP&E.

Stock-based Compensation

Under Canadian GAAP, the Company's stock option plan liability is valued using the intrinsic value method, calculated as the amount by which the market price of the Company's shares exceeds the exercise price of the option for vested options. Under IFRS, the stock option plan liability must be measured using a fair value option pricing model such as the Black-Scholes model. The Company has utilized the exemption in IFRS 1 under which options that were settled prior to January 1, 2010 will not have to be retrospectively restated. On transition to IFRS, the increase in stock-based compensation liability must be recorded in retained earnings.

Petroleum Revenue Tax

Under Canadian GAAP, the liability for the UK PRT is estimated using proved plus probable reserves and future prices and costs, and apportioned to accounting periods over the life of the field on the basis of total estimated future operating income. Under IFRS, the PRT liability is estimated using the balance sheet method in accordance with IAS 12 “Income Taxes”, where the liability is based on temporary differences in balance sheet assets and liabilities versus their tax basis. On transition to IFRS, the increase in PRT liability must be recorded in retained earnings.

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Income Taxes

Both Canadian GAAP and IFRS follow the liability method of accounting for income taxes, where tax liabilities and assets are recognized on temporary differences. However, there are certain exceptions to the treatment of temporary differences under IFRS that result in an adjustment to the Company's future tax liability under IFRS. In addition, the Company's future tax liability will be impacted by the tax effects of any changes noted in the above areas. On transition to IFRS, the decrease in the net future income tax liability must be recorded in retained earnings.

Other IFRS 1 Exemptions

The Company has adopted the following IFRS 1 transition exemptions:

§ The Company has elected to reset the foreign currency translation adjustment to $nil by transferring the Canadian GAAP balance to retained earnings on January 1, 2010, rather than retrospectively restating the balance.

§ The Company has adopted the IFRS 1 election to not restate business combinations entered into prior to January 1, 2010.

IFRS Transitional Impacts

Giving effect to the above-noted transitional impacts, the Company estimates that on adoption of IFRS, total Shareholders' Equity as at January 1, 2010 decreased by less than 4% compared to the balance previously determined under Canadian GAAP, resulting in a marginal increase in the Company's reported debt to book capitalization to 34% from 33%. After the adoption of IFRS, the Company expects that 2010 net earnings decreased by an amount estimated to be between $100 million to $200 million, primarily due to higher depletion, depreciation and amortization, offset by lower UK PRT expense. Further, on adoption of IFRS, the Company does not anticipate any significant differences in cash flow from operations as would have been previously reported. Readers are cautioned that these estimates are subject to change, should underlying IFRS standards and/or the interpretations thereof be revised, prior to the final release of the Company's December 31, 2011 annual consolidated financial statements.

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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 create shareholder value. Annual budgets are developed, scrutinized throughout the year and revised if necessary in the context of targeted financial ratios, 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 2011 to average between 385,000 bbl/d and 427,000 bbl/d of crude oil and NGLs and between 1,177 MMcf/d and 1,246 MMcf/d of natural gas.

Capital expenditures in 2011 are currently expected to be as follows:

($ millions)		2011 Guidance
Exploration and Production		
North America natural gas	$	600
North America crude oil and NGLs		1,895
North America bitumen (thermal oil)		
Primrose and future		830
Kirby Phase 1		515
Redwater Upgrading and Refining		340
North Sea		370
Offshore West Africa		135
Property acquisitions, dispositions and midstream		350
	$	5,035
Oils Sands Mining and Upgrading		
Sustaining and reclamation capital	$	220
Project capital		
Reliability – Tranche 2		370
Directive 74 and Technology		130
Phase 2A		200 – 230
Phase 2B		10 – 295
Phase 3		90 – 150
Phase 4		0 – 25
Total capital projects	$	800 – 1,200
Capitalized interest and other costs	$	100
	$	1,120 – 1,520
Total	$	6,155 – 6,555

The above capital expenditure budget incorporates the following levels of drilling activity:

(Number of wells)	2011 Guidance
Targeting natural gas	72
Targeting crude oil	1,190
Stratigraphic test / service wells – Exploration and Production	520
Stratigraphic test wells – Oil Sands Mining and Upgrading	280
Total	2,062

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North America Natural Gas

The 2011 North America natural gas drilling program is highlighted by the continued high-grading of the Company's natural gas asset base as follows:

(Number of wells)	2011 Guidance
Coal bed methane and shallow natural gas	4
Conventional natural gas	24
Cardium natural gas	4
Deep natural gas	39
Foothills natural gas	1
Total	72

North America Crude Oil and NGLs

The 2011 North America crude oil drilling program is highlighted by continued development of the Primrose thermal projects, Pelican Lake, and a strong primary heavy crude oil program, as follows:

(Number of wells)	2011 Guidance
Primary heavy crude oil	791
Bitumen (thermal oil)	217
Light and medium crude oil	138
Pelican Lake heavy crude oil	40
Total	1,186

Oil Sands Mining and Upgrading

Construction and commissioning of the third Ore Preparation Plant, along with the associated hydro-transport pipeline is on schedule for 2011. Engineering work as originally targeted for 2011 also continues on schedule. The Company is targeting additional cost estimate information for the Horizon expansion to be complete in the second quarter of 2011.

North Sea

During 2011, the majority of capital expenditures will be incurred to complete necessary sustaining capital activities on North Sea platforms.

Offshore West Africa

During 2011, the majority of capital expenditures will be incurred on drilling and completions.

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SENSITIVITY ANALYSIS

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 2010, excluding mark-to-market gains (losses) on risk management activities 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 with all other variables being held constant.

	Cash flow from operations ($ millions)	Cash flow from operations (per common share, basic)	Net earnings ($ millions)	Net earnings (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl (1)				
Excluding financial derivatives	$ 128	$ 0.12	$ 99	$ 0.09
Including financial derivatives	$ 128	$ 0.12	$ 99	$ 0.09
Natural gas – AECO C$0.10/Mcf (1)				
Excluding financial derivatives	$ 34	$ 0.03	$ 25	$ 0.02
Including financial derivatives	$ 38	$ 0.04	$ 29	$ 0.03
Volume changes				
Crude oil – 10,000 bbl/d	$ 175	$ 0.16	$ 104	$ 0.10
Natural gas – 10 MMcf/d	$ 9	$ 0.01	$ 1	$ –
Foreign currency rate change				
$0.01 change in US$ (1)				
Including financial derivatives	$ 101 – 103	$ 0.09	$ 40 – 41	$ 0.04
Interest rate change – 1%	$ 9	$ 0.01	$ 9	$ 0.01

(1) For details of financial instruments in place, refer to note 12 to the Company’s consolidated financial statements as at December 31, 2010.

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DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2010	2009	2008
Crude oil and NGLs (bbl/d)							
North America – Exploration and Production	252,450	275,584	267,177	286,698	270,562	234,523	243,826
North America – Oil Sands Mining and Upgrading	86,995	99,950	83,809	92,730	90,867	50,250	–
North Sea	36,879	37,669	27,045	31,701	33,292	37,761	45,274
Offshore West Africa	29,942	29,842	33,554	27,706	30,264	32,929	26,567
Total	406,266	443,045	411,585	438,835	424,985	355,463	315,667
Natural gas (MMcf/d)							
North America	1,193	1,219	1,234	1,223	1,217	1,287	1,472
North Sea	15	9	8	9	10	10	10
Offshore West Africa	18	9	16	20	16	18	13
Total	1,226	1,237	1,258	1,252	1,243	1,315	1,495
Barrels of oil equivalent (BOE/d)							
North America – Exploration and Production	451,269	478,770	472,850	490,470	473,447	449,054	489,081
North America – Oil Sands Mining and Upgrading	86,995	99,950	83,809	92,730	90,867	50,250	–
North Sea	39,352	39,175	28,321	33,186	34,973	39,444	46,956
Offshore West Africa	32,940	31,300	36,304	31,055	32,904	35,982	28,808
Total	610,556	649,195	621,284	647,441	632,191	574,730	564,845

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PER UNIT RESULTS – EXPLORATION AND PRODUCTION (1)

	Q1	Q2	Q3	Q4	2010	2009	2008
Crude oil and NGLs ($/bbl)							
Sales price (2)	$ 68.76	$ 63.62	$ 63.21	$ 67.74	$ 65.81	$ 57.68	$ 82.41
Royalties	10.08	8.95	9.05	12.14	10.09	6.73	10.48
Production expense	14.56	13.19	15.37	13.59	14.16	15.92	16.26
Netback	$ 44.12	$ 41.48	$ 38.79	$ 42.01	$ 41.56	$ 35.03	$ 55.67
Natural gas ($/Mcf)							
Sales price (2)	$ 5.19	$ 3.86	$ 3.75	$ 3.56	$ 4.08	$ 4.53	$ 8.39
Royalties (3)	0.41	0.25	0.11	0.07	0.20	0.32	1.46
Production expense	1.20	1.05	1.05	1.05	1.09	1.08	1.02
Netback	$ 3.58	$ 2.56	$ 2.59	$ 2.44	$ 2.79	$ 3.13	$ 5.91
Barrels of oil equivalent ($/BOE)							
Sales price (2)	$ 53.88	$ 47.97	$ 47.44	$ 50.41	$ 49.90	$ 44.87	$ 68.62
Royalties	7.07	6.10	5.83	7.83	6.72	4.72	9.78
Production expense	11.67	10.55	11.89	10.91	11.25	11.98	11.79
Netback	$ 35.14	$ 31.32	$ 29.72	$ 31.67	$ 31.93	$ 28.17	$ 47.05

(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) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

PER UNIT RESULTS – OIL SANDS MINING AND UPGRADING (1)

	Q1	Q2	Q3	Q4	2010	2009	2008
Crude oil and NGLs ($/bbl)							
SCO sales price (2)	$ 78.76	$ 75.97	$ 75.31	$ 81.51	$ 77.89	$ 70.83	$ –
Bitumen royalties (3)	2.83	2.69	2.57	2.77	2.72	2.15	–
Production expense	43.12	32.27	34.35	36.13	36.36	39.89	–
Netback	$ 32.81	$ 41.01	$ 38.39	$ 42.61	$ 38.81	$ 28.79	$ –

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

(2) Net of transportation.

(3) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

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TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2010	2009(1)
TSX – C$						
Trading volume (thousands)					661,832	1,040,320
Share price ($/share)						
High	$ 38.70	$ 40.08	$ 37.35	$ 45.00	$ 45.00	$ 39.50
Low	$ 33.81	$ 33.09	$ 31.97	$ 35.80	$ 31.97	$ 17.93
Close	$ 37.59	$ 35.33	$ 35.59	$ 44.35	$ 44.35	$ 38.00
Market capitalization as at December 31 ($ millions)					$ 48,379	$ 41,217
Shares outstanding (thousands)					1,090,848	1,084,654
NYSE – US$						
Trading volume (thousands)					759,327	1,514,614
Share price ($/share)						
High	$ 37.33	$ 40.12	$ 36.47	$ 44.77	$ 44.77	$ 38.26
Low	$ 31.42	$ 30.51	$ 30.00	$ 34.64	$ 30.00	$ 13.85
Close	$ 37.02	$ 33.23	$ 34.60	$ 44.42	$ 44.42	$ 35.98
Market capitalization as at December 31($ millions)					$ 48,455	$ 39,020
Shares outstanding (thousands)					1,090,848	1,084,654

(1) Per common share amounts have been restated to reflect a two-for-one common share split in May 2010.

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ADDITIONAL DISCLOSURE

Certifications

The required disclosure is included in Exhibits 2, 3, 4 and 5 of the Annual Report on Form 40-F

Disclosure Controls and Procedures

As of the end of the registrant's fiscal year ended December 31, 2010, an evaluation of the effectiveness of Canadian Natural's "disclosure controls and procedures" (as such term is defined in Rules 13a-15(e) 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 principal 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's Assessment of Internal Control Over Financial Reporting" that accompanies Canadian Natural's audited consolidated financial statements for the fiscal year ended December 31, 2010, 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 "Independent Auditors' Report" that accompanies Canadian Natural's audited consolidated financial statements for the fiscal year ended December 31, 2010, filed as part of this Annual Report on Form 40-F.

Changes in Internal Control Over Financial Reporting

During the fiscal year ended December 31, 2010, there were no changes in Canadian Natural's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, Canadian Natural's internal control 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 and is designed to ensure that Canadian Natural's business is consistently conducted in a 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. In the past fiscal year, there have not been any waivers, including implicit waivers, from any provisions of the Code of Ethics and there have been no substantive amendments.

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, 2010 and December 31, 2009, 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 and assistance related to Canadian Natural's conversion to International Financial Reporting Standards were $3,001,500 for 2010 and were $2,710,110 for 2009.

Audit-Related Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ending December 31, 2010 and December 31, 2009, for audit-related services by PwC including debt covenant compliance and Crown Royalty Statements, were $169,000 for 2010 and were $154,302 for 2009. 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, 2010 and December 31, 2009, for professional services rendered by PwC for tax services related to expatriate personal tax compliance, other corporate tax return matters and participation in a global taxation study were $149,000 for 2010 and were $131,653 for 2009. 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, 2010 and December 31, 2009 for other services were $54,100 for 2010 and were $9,500 for 2009. The fees for other services paid in 2010 related to the design of crown royalty compliance program and accessing resource materials through PwC's accounting literature library. Canadian Natural's Audit Committee approved all of the noted services.

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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 2010.

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. As at December 31, 2010, no entities were consolidated under CICA Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at December 31, 2010:

($ millions)	2011	2012	2013	2014	2015	Thereafter
Product transportation and pipeline	$ 228	$ 199	$ 172	$ 164	$ 152	$ 932
Offshore equipment operating lease	$ 141	$ 98	$ 97	$ 97	$ 81	$ 168
Offshore drilling	$ 7	$ –	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 18	$ 17	$ 19	$ 28	$ 27	$ 7,123
Long-term debt (2)	$ 398	$ 348	$ 798	$ 348	$ 400	$ 4,774
Interest expense (3)	$ 438	$ 400	$ 353	$ 333	$ 307	$ 4,236
Office leases	$ 27	$ 27	$ 28	$ 28	$ 32	$ 339
Other	$ 102	$ 66	$ 19	$ 16	$ 24	$ 10

(1) Amounts represent management's estimate of the future undiscounted payments to settle ARO related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2011 – 2015 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(2) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,436 million of revolving bank credit facilities due to the extendable nature of the facilities.

(3) Interest expense amounts represent the scheduled fixed rate and variable rate cash payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates as of December 31, 2010.

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. T. W. Faithfull, G. A. Filmon, G. D. Giffin, D. A. Tuer and Ms. C.M. Best, who chairs the Audit Committee.

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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 25th day of March, 2011.

CANADIAN NATURAL RESOURCES LIMITED

By: SIGNED “STEVE W. LAUT”
Name: Steve W. Laut
Title: President

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Documents filed as part of this report:

EXHIBIT INDEX

Exhibit No.	Description
1.	Supplementary Oil & Gas Information for the fiscal year ended December 31, 2010.
2.	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
3.	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) 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 Sproule International Limited, independent petroleum engineering consultants.
9.	Consent of GLJ Petroleum Consultants Ltd., independent petroleum engineering consultants.

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QUICKLINKS