CANADIAN NATURAL RESOURCES LTD
Form 40-F
March 28, 2012

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, 2011 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.
1,096,459,805 Common Shares outstanding as of December 31, 2011

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. 333-177401) 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 23, 2012, the noon buying rate for Canadian Dollars as expressed by the Federal Reserve Bank of New York was US$1.00 equals C$0.9983.

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, 2011.

B. Audited Annual Financial Statements

Canadian Natural's audited consolidated financial statements for the years ended December 31, 2011 and 2010, including the auditor's report with respect thereto.

C. Management's Discussion and Analysis

Canadian Natural's Management's Discussion and Analysis for the year ended December 31, 2011.

Supplementary Oil & Gas Information

For Canadian Natural's Supplementary Oil & Gas Information for the year ended December 31, 2011, see Exhibit 1 of this Annual Report on Form 40-F.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2011

March 27, 2012

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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

"bbl/d" means barrels per day

"Bcf" means one billion cubic feet

"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, prior to adoption of International Financial Reporting Standards on January 1, 2011

"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

“IFRS” means the International Financial Reporting Standards

“Mbbl” means one thousand barrels

“Mcf” means one thousand cubic feet

“Mcf/d” means one thousand cubic feet per day

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“MMbbl” means one million barrels

“MMBOE” means one million barrels of oil equivalent

“MMBtu” means one million British thermal units

“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 net present value of the future net revenue before income tax of the Company’s total proved plus probable crude oil and natural gas reserves prepared using forecast prices and costs discounted at 10%, plus the estimated market value of core unproved property, less net debt. Future development costs and associated material well abandonment costs have been applied against the future net revenue before income tax.

“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 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 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, income tax expenses, and other guidance provided throughout this Annual Information Form (“AIF”) 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 operations and future expansion, ability to recover insurance proceeds, Primrose, Pelican Lake, the Kirby Thermal Oil Sands Project, the Keystone XL Pipeline US Gulf coast expansion, and the construction and future operations of the North West Redwater bitumen upgrader and 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 as 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 disruptions or delays in the resumption of the mining, extracting or upgrading of 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, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or Management's estimates or opinions change.

Special Note Regarding Currency, Financial Information, 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. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6Mcf:1bbl conversion ratio may be misleading as an indication of value.

This AIF and the Company's consolidated financial statements and MD&A, herein incorporated by reference, have been prepared in accordance with IFRS, as issued by the International Accounting Standards Board. Unless otherwise stated, 2010 comparative figures have been restated in accordance with IFRS issued as at December 31, 2011. Comparative figures for 2009 have not been restated from Canadian GAAP as previously reported and may not be prepared on a basis consistent with IFRS as adopted.

For the year ended December 31, 2011 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, 2011 and a preparation date of February 13, 2012. Sproule evaluated the North America and International light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), natural gas and NGLs 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 and 2011 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 Form 40-F filed with the SEC in the "Supplementary Oil and Gas Information" section of the Company's Annual Report on pages 97 to 103 which is incorporated herein by reference.

Special Note Regarding Non-GAAP Financial Measures

This AIF 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, cash production costs, and net asset value. These financial measures are not defined by IFRS 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 IFRS, 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 IFRS in the "Financial Highlights" section of the Company's MD&A which is incorporated by reference into this document. The derivation of cash production costs is included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of 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.

On January 1, 2012 Aspect Energy Ltd., Creo Energy Ltd., 158024 Alberta Ltd. 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:

Subsidiary	Jurisdiction of Incorporation	% Ownership
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

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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.

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

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 South Phase 1 Project and the Board of Directors sanctioned Kirby South Phase 1 with construction commencing in the fourth quarter 2010. First steam in is targeted for 2013 and peak production is targeted to be 40,000 bbl/d with an overall cost target 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 $1.5 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

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 upgrader and 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 (the "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 a 30 year fee-for-service agreement to process bitumen supplied by the Company and 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.

On January 6, 2011, the Company suspended SCO production at its Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. On August 16, the Company successfully and safely resumed production with first pipeline deliveries commencing on August 18, 2011.

In November 2011 the Company issued US$500 million principal amount of 1.45% unsecured notes due November 14, 2014, and US$500 million principal amount of 3.45% unsecured notes due November 15, 2021. Net proceeds were used to repay bank indebtedness.

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 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.

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2012

The Company has entered into a 20 year transportation agreement to ship 120,000 bbl/d of heavy crude oil on the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf Coast. The Company also entered into a 20 year crude oil purchase and sales agreement to sell 100,000 bbl/d of heavy crude oil to a major US refiner. In January 2012, the Presidential Permit for the Keystone XL Pipeline was denied until such time as a new route through Nebraska is determined. Final recommendation from the US State Department is anticipated in the first quarter of 2013, with an expected pipeline in-service date in 2015.

On February 5, 2012 the Company temporarily suspended SCO production to complete unplanned maintenance on the fractionating unit in the primary upgrading facility. In March 2012, the maintenance was completed and pipeline deliveries re-commenced.

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 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, 2011, the Company had the following full time equivalent permanent employees:

North America, Exploration and Production	3,320
North America, Oil Sands Mining and Upgrading	1,591
North Sea	319
Offshore Africa	46
Total Company	5,276

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 35% of 2011 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 2011 production, is located principally in the Company's North Sea and Offshore Africa properties, with additional production in the provinces of Saskatchewan, British Columbia and Alberta. Primary heavy crude oil accounting for 18% of 2011 production, Pelican Lake heavy crude oil accounting for 6% of 2011 production, and our bitumen (thermal oil) accounting for 16% of 2011 production are in the provinces of Alberta and Saskatchewan. SCO from our oil sands mining operations in Northern Alberta accounts for approximately 7% of 2011 production. Midstream assets, comprised of three crude oil pipelines and an electricity co-generation facility, provide cost effective infrastructure supporting the heavy crude oil and bitumen operations.

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A. ENVIRONMENTAL MATTERS

The Company carries out its activities in compliance with 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. The Company has also adopted the Hydraulic Fracturing Operating Practices that were developed by the Canadian Association of Petroleum Producers ("CAPP"). In 2011, Canadian Natural expanded the environmental liability reduction program with the abandonment of 1,038 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 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 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, such as the Oil Sands Tailings Consortium to ensure 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 2011 the Company completed approximately 170 gas conservation projects in its primary heavy crude oil operations, resulting in a reduction of 2.3 million tonnes/year of CO2e. Over the past five years the Company has spent over $55 million in its primary heavy crude oil and in situ oil sands operations to conserve the equivalent of over 9.6 million tonnes of CO_2e. The Company also monitors the performance of its compressor fleet which is continually modified and optimized for improved 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 CO_2 capture and the sequestration of CO_2 in oil sands tailings. In its North Sea operations the Company continues to focus on its flare reduction program and also implemented a fuel gas import project to reduce diesel consumption. In its Offshore Africa operations, the Company implemented a flare reduction program in the Olowi field.

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%.

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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.

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 2011 was 16.5%, and is scheduled to decrease to 15% in 2012.

During 2011, the Canadian Federal government enacted legislation to implement several taxation changes. These changes include a requirement that, beginning in 2012, partnership income must be included in the taxable income of the corporate partners based on the tax year of the partner, rather than the fiscal year of the partnership. The legislation includes a five year transition provision and has no impact on net earnings.

In addition to government royalties, the Company is subject to federal and provincial income taxes in Canada at a combined rate of approximately 26.6% after allowable deductions for 2011.

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 (“SCT”) of 32% is charged on crude oil and natural gas profits but excludes any deduction for financing costs. In 2011, the UK Government raised the SCT rate from 20%-32% and as a result, the combined corporate and SCT rate has increased from 50% to 62%. 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.

In its 2011 Budget, the UK Government announced its intention to restrict tax relief on decommissioning costs to 50% for non-PRT fields and 75% for PRT paying fields. The proposed legislation to effect the restriction was released in 2011 for enactment in 2012.

Offshore 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.

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.

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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 Thermal 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 40% of the Company's 2011 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 assessments of the carrying value of its assets in accordance with IFRS. 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, mining, extracting, 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.

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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 in the estimated reserves, which may be material.

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.

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.

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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 are being developed that adopt a structured process to emission 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 is also developing a comprehensive management system for air pollutants.

In Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e 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 $25/tonne of CO_2e on fuel consumed and gas flared in the province. This rate is scheduled to increase to $30/tonne on July 1, 2012. As part of its involvement with the Western Climate Initiative, British Columbia may require certain upstream oil and gas facilities to participate in a regional cap and trade system. If such a system is implemented, it is not expected to be in place before 2014. It is estimated that four facilities in British Columbia will be included under the cap and trade system based on a proposed requirement of 25 kilotonnes of CO_2e annually. Saskatchewan released draft GHG regulations that regulate facilities emitting more than 50 kilotonnes of CO_2e annually and will likely require the North Tangleflags in situ heavy oil facility to meet the reduction target for its GHG emissions once the governing legislation comes into force. 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 CO_2 allocation. In Phase 2 (2008 – 2012) the Company's CO_2 allocation has been decreased below the Company's estimated current operations emissions. In Phase 3 (2013 - 2020) the Company's CO_2 allocation is expected to be further reduced, although details on Phase 3 have not yet been finalized. 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.

The US Environmental Protection Agency ("EPA") is proceeding to regulate GHGs under the Clean Air Act. This EPA action is subject to legal and political challenges, the outcome of which cannot be predicted. 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, including those related to Horizon and the Company's other existing and certain planned 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 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, 2011 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, 2011 and a preparation date of February 13, 2012. Sproule evaluated the North America and International light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), natural gas and NGLs 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 and 2011 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 Form 40-F filed with the SEC in the "Supplementary Oil and Gas Information" section of the Company's Annual Report on pages 97 to 103 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, 2011

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	94	76	204	193	1,831	2,975	56	2,950
Developed Non-Producing	3	20	1	71	-	170	2	125
Undeveloped	17	79	71	710	288	1,121	37	1,389
Total Proved	114	175	276	974	2,119	4,266	95	4,464
Probable	41	74	112	752	1,236	1,572	39	2,516
Total Proved plus Probable	155	249	388	1,726	3,355	5,838	134	6,980
North Sea								
Proved								
Developed Producing	59					7		60
Developed Non-Producing	13					56		22
Undeveloped	156					35		162
Total Proved	228					98		244
Probable	121					36		127
Total Proved plus Probable	349					134		371
Offshore Africa								
Proved								
Developed Producing	73					74		85
Developed Non-Producing	-					-		-
Undeveloped	36					9		38
Total Proved	109					83		123
Probable	56					46		64
Total Proved plus Probable	165					129		187
Total Company								
Proved								
Developed Producing	226	76	204	193	1,831	3,056	56	3,095
Developed Non-Producing	16	20	1	71	-	226	2	147

Undeveloped	209	79	71	710	288	1,165	37	1,589
Total Proved	451	175	276	974	2,119	4,447	95	4,831
Probable	218	74	112	752	1,236	1,654	39	2,707
Total Proved plus Probable	669	249	388	1,726	3,355	6,101	134	7,538

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Summary of Company Net Oil and Gas Reserves
As of December 31, 2011
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	63	155	143	1,514	2,663	39	2,437
Developed Non-Producing	3	17	1	51	-	141	2	98
Undeveloped	14	68	54	539	236	974	29	1,102
Total Proved	96	148	210	733	1,750	3,778	70	3,637
Probable	34	59	78	575	995	1,347	29	1,994
Total Proved plus Probable	130	207	288	1,308	2,745	5,125	99	5,631
North Sea								
Proved								
Developed Producing	59					7		60
Developed Non-Producing	13					56		22
Undeveloped	156					35		162
Total Proved	228					98		244
Probable	121					36		127
Total Proved plus Probable	349					134		371
Offshore Africa								
Proved								
Developed Producing	60					47		68
Developed Non-Producing	-					-		-
Undeveloped	27					7		28
Total Proved	87					54		96
Probable	44					29		49
Total Proved plus Probable	131					83		145
Total Company								
Proved								
Developed Producing	198	63	155	143	1,514	2,717	39	2,565
Developed Non-Producing	16	17	1	51	-	197	2	120

Undeveloped	197	68	54	539	236	1,016	29	1,292
Total Proved	411	148	210	733	1,750	3,930	70	3,977
Probable	199	59	78	575	995	1,412	29	2,170
Total Proved plus Probable	610	207	288	1,308	2,745	5,342	99	6,147

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NOTES

1. "Company 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. "Company 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 reserves 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, 2011
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	122,953	51,822	32,680	24,699	20,287	13.41
Developed Non-Producing	4,398	3,333	2,717	2,313	2,023	27.72
Undeveloped	55,164	22,913	12,721	8,109	5,525	11.54
Total Proved	182,515	78,068	48,118	35,121	27,835	13.23
Probable	119,047	46,972	20,899	10,233	5,217	10.48
Total Proved plus Probable	301,562	125,040	69,017	45,354	33,052	12.26
North Sea						
Proved						
Developed Producing	2,244	1,916	1,673	1,488	1,344	27.88
Developed Non-Producing	585	454	363	297	247	16.50
Undeveloped	9,018	5,502	3,541	2,380	1,658	21.86
Total Proved	11,847	7,872	5,577	4,165	3,249	22.86
Probable	9,710	4,918	2,865	1,851	1,288	22.56
Total Proved plus Probable	21,557	12,790	8,442	6,016	4,537	22.75
Offshore Africa						
Proved						
Developed Producing	3,665	2,418	1,811	1,468	1,251	26.63
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	2,156	1,275	833	584	429	29.75
Total Proved	5,821	3,693	2,644	2,052	1,680	27.54
Probable	3,859	1,993	1,149	722	486	23.45
Total Proved plus Probable	9,680	5,686	3,793	2,774	2,166	26.16
Total Company						
Proved						
Developed Producing	128,862	56,156	36,164	27,655	22,882	14.10
Developed Non-Producing	4,983	3,787	3,080	2,610	2,270	25.67
Undeveloped	66,338	29,690	17,095	11,073	7,612	13.23

Total Proved	200,183	89,633	56,339	41,338	32,764	14.17
Probable	132,616	53,883	24,913	12,806	6,991	11.48
Total Proved plus Probable	332,799	143,516	81,252	54,144	39,755	13.22

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

Summary of Net Present Values of Future Net Revenue After Income Taxes(1)
As of December 31, 2011
Forecast Prices and Costs

MM$	Discount @ 0%	Discount @ 5%	Discount @10%	Discount @ 15%	Discount @ 20%
North America					
Proved					
Developed Producing	94,804	41,019	26,294	20,041	16,534
Developed Non-Producing	3,292	2,489	2,024	1,718	1,500
Undeveloped	41,271	16,850	9,102	5,590	3,624
Total Proved	139,367	60,358	37,420	27,349	21,658
Probable	88,904	34,502	14,846	6,824	3,074
Total Proved plus Probable	228,271	94,860	52,266	34,173	24,732
North Sea					
Proved					
Developed Producing	597	526	473	433	401
Developed Non-Producing	223	179	148	126	108
Undeveloped	2,421	1,489	969	658	463
Total Proved	3,241	2,194	1,590	1,217	972
Probable	2,688	1,380	819	541	386
Total Proved plus Probable	5,929	3,574	2,409	1,758	1,358
Offshore Africa					
Proved					
Developed Producing	2,835	1,871	1,402	1,139	974
Developed Non-Producing	-	-	-	-	-
Undeveloped	1,645	985	652	461	342
Total Proved	4,480	2,856	2,054	1,600	1,316
Probable	2,954	1,552	911	582	398
Total Proved plus Probable	7,434	4,408	2,965	2,182	1,714
Total Company					
Proved					
Developed Producing	98,236	43,416	28,169	21,613	17,909
Developed Non-Producing	3,515	2,668	2,172	1,844	1,608
Undeveloped	45,337	19,324	10,723	6,709	4,429
Total Proved	147,088	65,408	41,064	30,166	23,946
Probable	94,546	37,434	16,576	7,947	3,858
Total Proved plus Probable	241,634	102,842	57,640	38,113	27,804

(1) After tax net present values consider the Company’s existing tax pool balances.

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Additional Information Concerning Future Net Revenue

The following table summarizes the undiscounted future net revenue as at December 31, 2011 using forecast prices and costs.

Total Future Net Revenue (Undiscounted)

	North America		North Sea		Offshore Africa		Total	
(MM$)	Proved	Proved Plus Probable	Proved	Proved Plus Probable	Proved	Proved Plus Probable	Proved	Proved Plus Probable
Revenue	507,805	776,940	26,712	43,406	9,528	14,471	544,045	834,817
Royalties	97,915	154,828	-	-	105	194	98,020	155,022
Operating Costs	183,667	248,317	9,531	15,433	2,201	2,367	195,399	266,117
Development Costs	43,053	71,395	5,230	6,289	1,401	2,182	49,684	79,866
Abandonment (1)	655	838	104	127	-	48	759	1,013
Future Net Revenue Before Income Taxes	182,515	301,562	11,847	21,557	5,821	9,680	200,183	332,799
Income Taxes	43,148	73,291	8,606	15,628	1,341	2,246	53,095	91,165
Future Net Revenue After Income Taxes(2)	139,367	228,271	3,241	5,929	4,480	7,434	147,088	241,634

(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, 2011 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$)	Unit Value(1) ($/BOE)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	11,516	24.92
	Primary Heavy Crude Oil (including solution gas)	3,924	26.24
	Pelican Lake Heavy Crude Oil (including solution gas)	4,559	21.65
	Bitumen (Thermal Oil)	13,066	17.83
	Synthetic Crude Oil	16,070	9.18
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	7,204	10.73
	Total	56,339	14.17
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	16,402	24.10
	Primary Heavy Crude Oil (including solution gas)	5,639	26.92
	Pelican Lake Heavy Crude Oil (including solution gas)	6,098	21.07
	Bitumen (Thermal Oil)	19,656	15.03
	Synthetic Crude Oil	24,237	8.83
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	9,220	10.08
	Total	81,252	13.22

(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, 2011. The following is a summary of the Sproule price forecast.

	Crude Oil and NGLs					Natural Gas			Inflation Rates	Exchange Rate
YEAR	WTI Cushing Oklahoma(1) (US$/bbl)	WCS(2) (C$/bbl)	Edmonton Par(3) (C$/bbl)	North Sea Brent(4) (US$/bbl)	Edmonton C5+(5) (C$/bbl)	Henry Hub Louisiana (US$/MMbtu)	AECO(6) (C$/MMbtu)	BC Westcoast Station 2(7) (C$/MMbtu)	%/Year	US$/C$
FORECAST										
2012	98.07	82.34	96.87	106.65	103.57	3.55	3.16	3.10	2.0	1.012
2013	94.90	79.69	93.75	102.15	100.23	4.18	3.78	3.72	2.0	1.012
2014	92.00	77.25	90.89	97.70	97.17	4.54	4.13	4.07	2.0	1.012
2015	97.42	81.80	96.23	103.26	102.89	5.95	5.53	5.47	2.0	1.012
2016	99.37	83.44	98.16	105.32	104.94	6.07	5.65	5.59	2.0	1.012
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	1.012

(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 crude 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 Africa light crude 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 crude 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 2.0% per year.

The Company's 2011 average pricing, excluding risk management activities, was $98.89/bbl for light and medium crude oil, $70.51/bbl for primary heavy crude oil, $71.45/bbl for Pelican Lake heavy crude oil, $68.55/bbl for bitumen (thermal oil), $99.74/bbl for SCO, $72.89/bbl for NGLs and $3.73/Mcf for natural gas.

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Reconciliation of Company Gross Reserves by Product
As of December 31, 2011
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, 2010	110	160	239	919	1,932	4,092	63	4,105
Discoveries	-	1	-	-	-	7	-	2
Extensions	7	47	8	20	-	220	18	137
Infill Drilling	6	8	-	2	-	55	3	28
Improved Recovery	-	1	-	-	-	-	-	1
Acquisitions	2	-	-	-	-	432	7	81
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	4	(177)	(1)	(26)
Technical Revisions	2	(4)	43	69	198	86	12	334
Production	(13)	(38)	(14)	(36)	(15)	(449)	(7)	(198)
December 31, 2011	114	175	276	974	2,119	4,266	95	4,464
North Sea								
December 31, 2010	252					78		265
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	28					3		29
Technical Revisions	(41)					20		(38)
Production	(11)					(3)		(12)
December 31, 2011	228					98		244
Offshore Africa								
December 31, 2010	120					92		135
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	2					-		2
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	-					-		-

Technical Revisions	(5)					(2)		(5)
Production	(8)					(7)		(9)
December 31, 2011	109					83		123
Total Company								
December 31, 2010	482	160	239	919	1,932	4,262	63	4,505
Discoveries	-	1	-	-	-	7	-	2
Extensions	7	47	8	20	-	220	18	137
Infill Drilling	8	8	-	2	-	55	3	30
Improved Recovery	-	1	-	-	-	-	-	1
Acquisitions	2	-	-	-	-	432	7	81
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	28	-	-	-	4	(174)	(1)	3
Technical Revisions	(44)	(4)	43	69	198	104	12	291
Production	(32)	(38)	(14)	(36)	(15)	(459)	(7)	(219)
December 31, 2011	451	175	276	974	2,119	4,447	95	4,831

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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, 2010	40	57	109	783	956	1,430	20	2,203
Discoveries	-	-	-	-	-	1	-	-
Extensions	3	22	6	17	388	122	11	468
Infill Drilling	3	4	-	1	-	54	4	21
Improved Recovery	1	3	-	-	-	-	-	4
Acquisitions	-	-	-	-	-	104	2	19
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	-	-	-	-	-	(34)	(1)	(7)
Technical Revisions	(6)	(12)	(3)	(49)	(108)	(104)	3	(192)
Production	-	-	-	-	-	-	-	-
December 31, 2011	41	74	112	752	1,236	1,572	39	2,516
North Sea								
December 31, 2010	124					29		129
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	(26)					-		(26)
Technical Revisions	23					7		24
Production	-					-		-
December 31, 2011	121					36		127
Offshore Africa								
December 31, 2010	57					46		65
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	-					-		-
Technical Revisions	(1)					-		(1)
Production	-					-		-
December 31, 2011	56					46		64

Total Company								
December 31, 2010	221	57	109	783	956	1,505	20	2,397
Discoveries	-	-	-	-	-	1	-	-
Extensions	3	22	6	17	388	122	11	468
Infill Drilling	3	4	-	1	-	54	4	21
Improved Recovery	1	3	-	-	-	-	-	4
Acquisitions	-	-	-	-	-	104	2	19
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	(26)	-	-	-	-	(34)	(1)	(33)
Technical Revisions	16	(12)	(3)	(49)	(108)	(97)	3	(169)
Production	-	-	-	-	-	-	-	-
December 31, 2011	218	74	112	752	1,236	1,654	39	2,707

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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, 2010	150	217	348	1,702	2,888	5,522	83	6,308
Discoveries	-	1	-	-	-	8	-	2
Extensions	10	69	14	37	388	342	29	605
Infill Drilling	9	12	-	3	-	109	7	49
Improved Recovery	1	4	-	-	-	-	-	5
Acquisitions	2	-	-	-	-	536	9	100
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	-	-	-	-	4	(211)	(2)	(33)
Technical Revisions	(4)	(16)	40	20	90	(18)	15	142
Production	(13)	(38)	(14)	(36)	(15)	(449)	(7)	(198)
December 31, 2011	155	249	388	1,726	3,355	5,838	134	6,980
North Sea								
December 31, 2010	376					107		394
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	2					3		3
Technical Revisions	(18)					27		(14)
Production	(11)					(3)		(12)
December 31, 2011	349					134		371
Offshore Africa								
December 31, 2010	177					138		200
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	2					-		2
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	-					-		-
Technical Revisions	(6)					(2)		(6)
Production	(8)					(7)		(9)
December 31, 2011	165					129		187

Total Company								
December 31, 2010	703	217	348	1,702	2,888	5,767	83	6,902
Discoveries	-	1	-	-	-	8	-	2
Extensions	10	69	14	37	388	342	29	605
Infill Drilling	11	12	-	3	-	109	7	51
Improved Recovery	1	4	-	-	-	-	-	5
Acquisitions	2	-	-	-	-	536	9	100
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	2	-	-	-	4	(208)	(2)	(30)
Technical Revisions	(28)	(16)	40	20	90	7	15	122
Production	(32)	(38)	(14)	(36)	(15)	(459)	(7)	(219)
December 31, 2011	669	249	388	1,726	3,355	6,101	134	7,538

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At December 31, 2011, the Company's gross proved crude oil and NGLs reserves totaled 4,090 MMbbl, and gross proved plus probable crude oil and NGLs reserves totaled 6,521 MMbbl. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 437 MMbbl, and additions to proved plus probable reserves amounted to 722 MMbbl. Net positive revisions due to economic factors and technical revisions amounted to 305 MMbbl for proved reserves and 125 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, partially offset by negative revisions in the North Sea due to cancellation of certain of the Company's activities that became uneconomic as a result of changes in the UK fiscal structure.

At December 31, 2011, the Company's gross proved natural gas reserves totaled 4,447 Bcf, and gross proved plus probable natural gas reserves totaled 6,101 Bcf. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 644 Bcf, and additions to proved plus probable reserves amounted to 793 Bcf. Net negative revisions due to economic factors and technical revisions amounted to 70 Bcf for proved reserves and 201 Bcf for proved plus probable reserves, primarily due to lower estimated future benchmark pricing.

Additional Information Relating To Reserves Data

Undeveloped Reserves

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.

The tables below do not include volumes of proved undeveloped and probable undeveloped reserves first attributed in 2009 and in aggregate before that time. This information was not evaluated prior to 2010 due to the Company having been 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.

Proved Undeveloped Reserves

Year	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)
2010 First Attributed	3	34	3	156	-	209	7	238
2010 Total	195	66	85	687	128	1,082	17	1,358
2011 First Attributed	8	29	8	70	-	240	21	176
2011 Total	209	79	71	710	288	1,165	37	1,589

Probable Undeveloped Reserves

Year	Light and Medium Crude Oil	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)

	(MMbbl)		(MMbbl)					
2010 First Attributed	3	16	2	224	-	103	3	265
2010 Total	146	27	43	777	862	470	6	1,939
2011 First Attributed	4	17	6	17	388	160	14	473
2011 Total	153	37	38	749	1,142	564	20	2,233

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Bitumen (thermal oil) accounts for approximately 45% of the Company's total proved undeveloped BOE reserves and 34% 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 (thermal oil), 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.

Future Development Costs

The following table summarizes the undiscounted future development costs, excluding abandonment costs, using forecast prices and costs as of December 31, 2011.

Future Development Costs (Undiscounted)

	North America		North Sea		Offshore Africa		Total	
Year	Proved (MM$)	Proved plus Probable (MM$)	Proved (MM$)	Proved plus Probable (MM$)	Proved (MM$)	Proved plus Probable (MM$)	Proved (MM$)	Proved plus Probable (MM$)
2012	3,417	4,647	328	328	113	113	3,858	5,088
2013	3,539	5,471	316	316	244	308	4,099	6,095
2014	2,680	5,243	234	234	128	283	3,042	5,760
2015	2,156	5,841	550	550	6	6	2,712	6,397
2016	1,283	3,538	242	242	64	234	1,589	4,014
Thereafter	29,978	46,655	3,560	4,619	846	1,238	34,384	52,512
Total	43,053	71,395	5,230	6,289	1,401	2,182	49,684	79,866

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, 2011 and 2010.

	2011 Average Daily Production Rates		2010 Average Daily Production Rates	
Region	Crude oil & NGLs (Mbbl)	Natural gas (MMcf)	Crude oil & NGLs (Mbbl)	Natural gas (MMcf)
North America				
Northeast British Columbia	8.0	345	5.5	305
Northwest Alberta	21.2	485	17.0	464
Northern Plains	247.7	240	229.1	296
Southern Plains	11.4	158	11.2	148
Southeast Saskatchewan	7.1	2	7.6	3
Oil sands Mining & Upgrading	40.4	-	90.9	-
Non-core regions	0.2	1	0.2	1
North America Total	336.0	1,231	361.5	1,217
International				
North Sea UK Sector	30.0	7	33.3	10
Offshore Africa	23.0	19	30.2	16
International Total	53.0	26	63.5	26
Company Total	389.0	1,257	425.0	1,243

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, a natural gas processing plant with a design capacity of 50 MMcf/d was completed at our Septimus Montney shale gas play and in 2011 the Company completed a pipeline to a deep cut gas facility which increased liquids recoveries. 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 both 2011 and 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 2011, approximately 50% 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

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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 South Phase 1 Project, located approximately 85 km northeast of Lac la Biche, was approved in the third quarter 2010 and the Board of Directors sanctioned Kirby South Phase 1 with construction commencing in the fourth quarter 2010. During 2011, drilling was completed on the second of seven pads. First steam in is targeted for 2013 and is expected to add 40,000 bbl/day of production.

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. In 2011 additional assets in the area were acquired which further complemented the asset base.

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 40,434 bbl/day in 2011.

Phase 2/3 spending during 2011 continued to be focused on final construction and pre-commissioning of the third ore preparation plant and associated hydro-transport, as well as additional product tankage, the butane treatment unit and the sulphur recovery unit. Final commissioning of the ore preparation plant and associated hydro-transport was completed in January 2012.

As a result of a fire at Horizon's primary upgrading coking plant on January 6, 2011, all SCO production was suspended. On August 16, 2011 the Company successfully and safely recommenced operations. First pipeline deliveries commenced on August 18, 2011. On February 5, 2012 the Company temporarily suspended SCO production to complete unplanned maintenance on the fractionating unit in the primary upgrading facility. In March 2012, the maintenance was completed and pipeline deliveries re-commenced.

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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 2011, 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 11 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 2011, the Company continued drilling operations on the three Ninian platforms, facilities upgrade projects at Lyell and ongoing capital turnaround projects at Tiffany and Murchison. The Company also continued planning for decommissioning of the Murchison field.

In March 2011, the UK government enacted an increase to the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50%-62%. This resulted in an increase to the overall corporate tax rate applicable to net operating income from oil and gas activities to 62% for non-PRT paying fields and 81% for PRT paying fields, after allowing for deduction for capital and abandonment expenditures. As a result of the increase in the corporate income tax rate, the Company’s development activities in 2011 in the North Sea were reduced. The Company is continuing to high grade all North Sea prospects for potential development opportunities in 2012 and future years.

In December 2011 storm damage was sustained to the Banff FPSO and subsea infrastructure. Operations at Banff/Kyle were suspended and appropriate shut down procedures were activated. The FPSO and associated floating storage unit have been removed from the field and the extent of the damage, including associated costs and timing of returning to the field, are currently being assessed.

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Offshore 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.

Political unrest resulting from the Presidential Election in November 2010 has had minimal impact on the Company's operations. A new Government was formed in June 2011 and the security situation continues to improve.

During 2011 the Company sanctioned an 8 well drilling program at the Espoir Field in Cote d'Ivoire. Preparations are ongoing and a rig has been contracted to commence drilling operations targeted for late 2012.

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Gabon

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 during the second quarter of 2009 at Platform C and during 2010 on Platform A and B. Production has been below expectation in the field, resulting in the Company curtailing the drilling program in the first quarter of 2011. In mid 2011, production was temporarily suspended as a result of a failure in the mid-water arch. Production was reinstated in mid-August 2011.

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, 2011.

	Natural gas wells		Crude oil wells		Total wells	
Producing	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	11,523.0	8,863.6	7,382.0	6,657.9	18,905.0	15,521.5
British Columbia	1,804.0	1,410.1	246.0	199.6	2,050.0	1,609.7
Saskatchewan	6,372.0	5,710.9	2,553.0	2,091.5	8,925.0	7,802.4
Manitoba	-	-	171.0	168.1	171.0	168.1
Total Canada	19,699.0	15,984.6	10,352.0	9,117.1	30,051.0	25,101.7
United States	2.0	0.5	2.0	0.3	4.0	0.8
North Sea UK Sector	1.0	0.1	82.0	72.2	83.0	72.3
Offshore Africa						
Gabon	-	-	13.0	12.0	13.0	12.0
Côte d’Ivoire	-	-	23.0	13.4	23.0	13.4
Total	19,702.0	15,985.2	10,472.0	9,215.0	30,174.0	25,200.2

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, 2011.

	Natural gas wells		Crude oil wells		Total wells	
Non Producing	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	4,155.0	3,265.2	5,789.0	5,250.8	9,944.0	8,516.0
British Columbia	1,136.0	901.1	328.0	283.9	1,464.0	1,185.0
Saskatchewan	888.0	811.0	2,028.0	1,711.5	2,916.0	2,522.5
Manitoba	-	-	54.0	51.6	54.0	51.6
Northwest Territories	27.0	6.9	2.0	0.3	29.0	7.2
Total Canada	6,206.0	4,984.2	8,201.0	7,298.1	14,407.0	12,282.3
United States	1.0	0.1	3.0	0.5	4.0	0.6
North Sea UK Sector	2.0	0.1	35.0	25.6	37.0	25.7
Offshore Africa						
Gabon	-	-	-	-	-	-
Côte d’Ivoire	-	-	7.0	4.0	7.0	4.0
Total	6,209.0	4,984.4	8,246.0	7,328.2	14,455.0	12,312.6

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Properties With No Attributed Reserves

The following table summarizes the Company's landholdings as at December 31, 2011.

Region (thousands of acres)	Proved Properties		Unproved Properties		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	%
North America							
Northeast British Columbia	1,005	840	3,938	3,051	4,943	3,891	79
Northwest Alberta	1,249	967	2,413	1,986	3,662	2,953	81
Northern Plains	2,344	1,998	7,274	6,581	9,618	8,579	89
Southern Plains	1,734	1,509	1,121	989	2,855	2,498	88
Southeast Saskatchewan	128	117	109	102	237	219	92
Thermal in situ Oil Sands	74	73	920	817	994	890	90
Oil Sands Mining & Upgrading	22	22	59	59	81	81	100
Non-core regions	12	3	1,087	303	1,099	306	28
North America Total	6,568	5,529	16,921	13,888	23,489	19,417	83
International							
North Sea UK Sector	68	57	158	128	226	185	82
Offshore Africa							
Côte d'Ivoire	10	6	92	53	102	59	58
Gabon	5	4	147	136	152	140	92
South Africa	-	-	4,002	4,002	4,002	4,002	100
International Total	83	67	4,399	4,319	4,482	4,386	98
Company Total	6,651	5,596	21,320	18,207	27,971	23,803	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 million net acres attributed to our North America properties which are currently expected to expire by December 31, 2012.

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 2011, the Company's capital expenditures included $213 million for abandonment expenditures (2010 - $179 million). The Company expects approximately $345 million of abandonment expenditures to be incurred over the next 3 years.

The Company's estimated undiscounted ARO at December 31, 2011 was as follows:

Estimated ARO, undiscounted (MM$)	2011	2010
Exploration and Production	$4,720	$4,125
North America, Oil Sands Mining and Upgrading	2,235	1,733
Midstream	10	10
North Sea	1,966	1,400
Offshore Africa	444	232
	9,375	7,500
North Sea PRT recovery	(626)	(423)
	$8,749	$7,077

The 2011 ARO liability discounted at 10% is approximately $1,236 million. The abandonment and reclamation costs were not deducted in estimating the Company's future net revenue for December 31, 2011 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 42,378 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 $626 million (2010 - $423 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 $8,749 million (2010 - $7,077 million).

2011 Costs Incurred in Crude Oil, NGLs and Natural Gas Activities

MM$	North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	1,012	-	-	1,012
Unproved	59	-	-	59
Exploration	250	1	2	253
Development	5,559	235	76	5,870
Costs Incurred	6,880	236	78	7,194

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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, 2011 by geographic region along with a general discussion of 2012 activity.

		2011 Exploratory					
North America		Crude Oil	Natural Gas	Dry	Service	Stratigraphic	Total
Northeast British Columbia	Gross	-	3.0	-	-	-	3.0
	Net	-	2.1	-	-	-	2.1
Northwest Alberta	Gross	5.0	16.0	-	-	-	21.0
	Net	4.5	14.0	-	-	-	18.5
Northern Plains	Gross	93.0	1.0	15.0	-	-	109.0
	Net	90.8	1.0	14.0	-	-	105.8
Southern Plains	Gross	2.0	-	2.0	-	-	4.0
	Net	2.0	-	2.0	-	-	4.0
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	103.0	20.0	18.0	-	-	141.0
	Net	100.3	17.1	17.0	-	-	134.4
North Sea UK Sector	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Offshore Africa	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	
Company Total	Gross	103.0	20.0	18.0	-	-	141.0
	Net	100.3	17.1	17.0	-	-	134.4

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		2011 Development					
North America		Crude Oil	Natural Gas	Dry	Service	Stratigraphic	Total
Northeast British Columbia	Gross	11.0	15.0	-	2.0	-	28.0
	Net	11.0	13.2	-	2.0	-	26.2
Northwest Alberta	Gross	36.0	45.0	-	-	-	81.0
	Net	26.9	42.6	-	-	-	69.5
Northern Plains	Gross	936.0	22.0	27.0	35.0	331.0	1,351.0
	Net	894.7	10.1	27.0	34.6	329.1	1,295.5
Southern Plains	Gross	35.0	-	3.0	4.0	-	42.0
	Net	33.8	-	3.0	4.0	-	40.8
Southeast Saskatchewan	Gross	38.0	-	-	-	-	38.0
	Net	36.3	-	-	-	-	36.3
Oil Sands Mining and Upgrading	Gross	-	-	-	11.0	275.0	286.0
	Net	-	-	-	11.0	275.0	286.0
Non-core Regions	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
North America Total	Gross	1,056.0	82.0	30.0	52.0	606.0	1,826.0
	Net	1,002.7	65.9	30.0	51.6	604.1	1,754.3
North Sea UK Sector	Gross	-	-	-	1.0	-	1.0
	Net	-	-	-	0.9	-	0.9
Offshore Africa	Gross	-	-	1.0	-	-	1.0
	Net	-	-	0.9	-	-	0.9
Company Total	Gross	1,056.0	82.0	31.0	53.0	606.0	1,828.0
	Net	1,002.7	65.9	30.9	52.5	604.1	1,756.1

Total success rate excluding service and stratigraphic test wells for 2011 is 96%.

2012 North America Natural Gas Activity

The 2012 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)	2012 Guidance
Coal bed methane and shallow natural gas	-
Conventional natural gas	4
Cardium natural gas	1
Deep natural gas	40
Total	45

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2012 North America Crude Oil and NGLs Activity

The 2012 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)	2012 Guidance
Primary heavy crude oil	808
Bitumen (thermal oil)	159
Light and Medium crude oil	134
Pelican Lake heavy crude oil	13
Total	1,114

2012 Oil Sands Mining and Upgrading Activity

During 2012, Phase 2/3 will continue to progress engineering and construction activities with respect to extraction, froth treatment, hydrotreatment, the butane storage unit, tailings and the vacuum unit in accordance with the overall Phase 2/3 execution schedule and strategy.

2012 North Sea Activity

During 2012, the majority of capital expenditures will be incurred to complete necessary sustaining capital activities on North Sea platforms.

2012 Offshore Africa Activity

During 2012, the majority of capital expenditures will be incurred on drilling and completions at Espoir.

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Production Estimates

The following table illustrates the estimated 2012 gross daily proved and probable production reflected in the reserve reports as of December 31, 2011 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	38,181	107,601	48,647	104,775	108,902	1,174	22,812	626,585
North Sea	27,494					6		28,494
Offshore Africa	21,473					31		26,640
Total Proved	87,148	107,601	48,647	104,775	108,902	1,211	22,812	681,718
PROBABLE								
North America	1,982	11,594	1,095	1,660	5,536	54	1,015	31,882
North Sea	727					1		894
Offshore Africa	1,016					-		1,016
Total Probable	3,725	11,594	1,095	1,660	5,536	55	1,015	33,792

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Production History

	2011 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)	37,244	34,681	35,277	39,744	36,739
Netbacks ($/bbl)					
Sales price (2)	$ 80.35	$ 93.57	$ 82.49	$ 91.15	$ 86.92
Royalties	15.36	18.32	17.25	17.45	17.08
Production expenses	19.52	20.45	21.56	19.68	20.27
Netback	$ 45.47	$ 54.80	$ 43.68	$ 54.02	$ 49.57
Primary Heavy Crude Oil					
Average daily production (before royalties) (bbl/d)	96,909	101,320	101,506	111,495	102,844
Netbacks ($/bbl)					
Sales price (2)	$ 59.62	$ 75.85	$ 65.08	$ 79.91	$ 70.51
Royalties	11.48	12.75	10.78	12.58	11.92
Production expenses	13.02	14.72	14.03	13.91	13.93
Netback	$ 35.12	$ 48.38	$ 40.27	$ 53.42	$ 44.66
Pelican Lake Heavy Crude Oil					
Average daily production (before royalties) (bbl/d)	39,342	34,613	38,260	40,179	38,101
Netbacks ($/bbl)					
Sales price (2)	$ 62.78	$ 74.95	$ 66.33	$ 81.64	$ 71.45
Royalties	7.58	5.44	7.11	16.38	9.32
Production expenses	11.34	13.61	12.79	12.21	12.46
Netback	$ 43.86	$ 55.90	$ 46.43	$ 53.05	$ 49.67
Bitumen (Thermal Oil)					
Average daily production (before royalties) (bbl/d)	97,894	106,345	110,245	78,160	98,140
Netbacks ($/bbl)					
Sales price (2)	$ 56.79	$ 75.73	$ 65.31	$ 78.38	$ 68.55
Royalties	10.44	13.85	10.55	21.56	13.69

Production expenses	10.11	9.10	10.95	14.79	11.02
Netback	$ 36.24	$ 52.78	$ 43.81	$ 42.03	$ 43.84
SCO					
Average daily production (before royalties) (bbl/d)	7,269	–	50,354	102,952	40,434
Netbacks ($/bbl)					
Sales price (2)	$ 82.93	$ –	$ 96.19	$ 103.16	$ 99.74
Royalties (3)	4.14	–	3.48	4.21	3.99
Production expenses (4)	45.69	–	35.85	36.04	36.64
Netback	$ 33.10	$ –	$ 56.86	$ 62.91	$ 59.11
Natural Gas					
Average daily production (before royalties) (MMcf/d)	1,225	1,218	1,226	1,255	1,231
Netbacks ($/Mcf)					
Sales price (2)	$ 3.77	$ 3.76	$ 3.67	$ 3.36	$ 3.64
Royalties	0.12	0.23	0.15	0.15	0.16
Production expenses	1.16	1.09	1.13	1.12	1.12
Netback	$ 2.49	$ 2.44	$ 2.39	$ 2.09	$ 2.36

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Production History

	2011				
	Q1	Q2	Q3	Q4	Year Ended
Natural Gas Liquids					
Average daily production (before royalties) (bbl/d)	18,741	18,756	19,383	22,261	19,794
Netbacks ($/bbl)					
Sales price (2)	$69.05	$73.41	$71.36	$76.95	$72.89
Royalties	19.89	22.11	22.68	24.17	22.32
Production expenses	8.40	8.66	9.01	8.91	8.76
Netback	$40.76	$42.64	$39.67	$43.87	$41.81
North Sea production and netbacks by product type (1)					
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	34,101	32,866	26,350	26,769	29,992
Netbacks ($/bbl)					
Sales price (2)	$102.51	$112.32	$109.28	$109.71	$108.56
Royalties	0.28	0.25	0.27	0.23	0.26
Production expenses	30.46	34.20	49.72	36.45	37.06
Netback	$71.77	$77.87	$59.29	$73.03	$71.24
Natural gas					
Average daily production (before royalties) (MMcf/d)	9	7	5	6	7
Netbacks ($/Mcf)					
Sales price (2)	$3.56	$5.19	$3.26	$4.17	$4.07
Royalties	–	–	–	–	–
Production expenses	2.65	2.61	2.68	3.51	2.83
Netback	$0.91	$2.58	$0.58	$0.66	$1.24
Offshore Africa production and netbacks by product type (1)					
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	25,488	21,334	22,525	22,726	23,009
Netbacks ($/bbl)					
Sales price (2)	$97.09	$110.42	$114.44	$102.74	$105.53
Royalties	8.66	0.71	20.69	15.35	12.47
Production expenses	19.13	21.36	19.91	22.16	20.72
Netback	$69.30	$88.35	$73.84	$65.23	$72.34
Natural gas					
Average daily production (before royalties) (MMcf/d)	22	15	21	19	19
Netbacks ($/Mcf)					

Sales price (2)	$7.34	$8.83	$9.38	$12.79	$9.56
Royalties	0.97	1.07	1.90	2.33	1.59
Production expenses	1.25	2.35	2.16	2.52	2.03
Netback	$5.12	$5.41	$5.32	$7.94	$5.94

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

(4) Amounts expressed on a per unit basis are based on sales volumes excluding the period during suspension of production.

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SELECTED FINANCIAL INFORMATION

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

		Year Ended December 31	
($ millions, except per common share information)		2011	2010
Product sales		$ 15,507	$ 14,322
Net earnings		$ 2,643	$ 1,673
Per common share	- basic	$ 2.41	$ 1.54
	- diluted	$ 2.40	$ 1.53
Adjusted net earnings from operations (1)		$ 2,540	$ 2,444
Per common share	- basic	$ 2.32	$ 2.25
	- diluted	$ 2.30	$ 2.23
Cash flow from operations (1)		$ 6,547	$ 6,333
Per common share	- basic	$ 5.98	$ 5.82
	- diluted	$ 5.94	$ 5.78
Total assets		$ 47,278	$ 42,954
Total long-term liabilities		$ 20,346	$ 18,880

(1) These non-GAAP measures are reconciled to net earnings as determined in accordance with IFRS 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.

	2011	2010	2009
Cash dividends declared per common share	$0.36	$0.30	$0.21

In March 2012, the Company's Board of Directors resolved to increase the cash dividend on common shares for the twelfth year in a row and approved a 17% increase in the quarterly dividend from $0.09 per common share in 2011 to $0.105 per common share, effective with the April 1, 2012 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.

At the shareholders' meeting to be held on May 3, 2012, the shareholders will be asked to consider an amendment to the Articles of the Corporation redesignating and changing the provisions of the currently authorized Class 1 Preferred Shares to Preferred Shares, which shall be issuable in a series. The amendment, if approved, will bring the preferred share provisions to a more current standard.

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 to 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 to 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 Investors Service, Inc. ("Moody's"), "BBB+" by Standard & Poor's Ratings Services ("S&P") and "BBB (high)" with a stable trend by DBI Limited ("DBRS"). S&P assigns a rating outlook to Canadian Natural and not to individual debt instruments. S&P has assigned a stable 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.

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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.

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.

2011 Monthly Historical Trading on TSX

Month	High	Low	Close	Volume Traded
January	$44.98	40.05	44.65	72,234,881
February	$49.33	43.20	48.93	51,790,961
March	$50.50	43.11	47.94	64,254,266
April	$48.41	41.85	44.51	64,279,412
May	$44.89	38.92	42.17	72,554,729
June	$42.43	37.43	40.43	61,393,430
July	$42.14	38.31	38.58	42,281,690
August	$38.56	32.74	37.00	79,775,832
September	$37.43	29.80	30.77	77,276,628
October	$36.58	27.25	35.16	74,977,736
November	$39.41	33.28	38.31	82,748,878
December	$38.88	34.75	38.15	56,475,894

In the first quarter 2011, the Company announced a Normal Course Issuer Bid to purchase up to 2.5% of its issued and outstanding common shares or 27,406,131 common shares, through the facilities of TSX and the NYSE during the twelve month period commencing April 6, 2011 and ending April 5, 2012. During 2011, the Company purchased a total of 3,071,100 common shares for cancellation at an average purchase price of $33.68 per common share for a total cost of $104 million.

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DIRECTORS AND OFFICERS

The names, municipalities of residence, offices held with the Company and principal occupations of the Directors and Executive 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 14, 2012 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 58)	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, Superior Plus Corporation and Alta Gas Ltd. She is also a member of the Board of the Alberta Children's Hospital Foundation and The Calgary Foundation and serves as a volunteer member of the Audit Committee of the Calgary Stampede and of the Audit Committee of the University of Calgary.
N. Murray Edwards Calgary/Banff, Alberta Canada	Vice-Chairman and Director (5) (age 52)	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 67)	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, a private pension trust.
Honourable Gary A. Filmon, P.C., O.C., O.M. Winnipeg, Manitoba	Director (1)(4) (age 69)	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

Canada	directors of MTS Allstream Inc., Arctic Glacier Income Trust, Exchange Income Corporation, and FWS Construction Inc.

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Name	Position Presently Held	Principal Occupation During Past 5 Years
Christopher L. Fong Calgary, Alberta Canada	Director (3)(5) (age 62)	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. He has served as Chair of EducationMatters and as a Governor of Honen's, an International Piano Competition. He is currently Chair of UNICEF Canada and is serving on the board of directors of Anderson Energy Ltd., Westfire Energy Ltd., Computer Modelling Group 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.
Ambassador Gordon D. Giffin Atlanta, Georgia USA	Director (1)(4) (age 62)	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 64)	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, Aston Hill Energy 2010 GP Inc. (formerly Aston Hill Energy 2009 Inc.), Trilogy Energy Corp., Manitok Energy Inc. and Catapult Energy 2008 Inc. (General Partner of Catapult Energy 2008 FTS Limited Partnership).
Steve W. Laut Calgary, Alberta Canada	President and Director (age 54)	Officer of the Company. He has served continuously as a director of the Company since August 2006.
Keith A.J. MacPhail	Director (3)(5)	

Calgary, Alberta Canada	(age 55)	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 66)	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 64)	Deputy Chair, TD Bank 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.

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Name	Position Presently Held	Principal Occupation During Past 5 Years
James S. Palmer, C.M., A.O.E., Q.C. Calgary, Alberta Canada	Director (5) (age 83)	Chairman Emeritus 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 72)	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., Alberta Health Services and Aston Hill Financial.
David A. Tuer Calgary, Alberta Canada	Director (1)(5) (age 62)	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 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 Pace Oil and Gas Ltd. and Altalink Management LLP., a private limited partnership.
Corey B. Bieber Calgary, Alberta Canada	Vice-President, Finance and Investor Relations (age 48)	Officer of the Company.
Mary-Jo E. Case Calgary, Alberta Canada	Vice-President, Land (age 53)	Officer of the Company.
Réal M. Cusson	Senior Vice-President,	Officer of the Company.

Calgary, Alberta Canada	Marketing (age 61)	
Randall S. Davis Calgary, Alberta Canada	Vice-President, Finance & Accounting (age 45)	Officer of the Company.
Réal J. H. Doucet Calgary, Alberta Canada	Senior Vice-President, Horizon Projects (age 59)	Officer of the Company.
Peter J. Janson Calgary, Alberta Canada	Senior Vice-President, Horizon Operations (age 54)	Officer of the Company.
Terry J. Jocksch Calgary, Alberta Canada	Senior Vice-President, Thermal and International (age 44)	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.

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Name	Position Presently Held	Principal Occupation During Past 5 Years
Allen M. Knight Calgary, Alberta Canada	Senior Vice-President, International & Corporate Development (age 62)	Officer of the Company.
John G. Langille Calgary, Alberta Canada	Vice-Chairman (age 66)	Officer of the Company.
Tim S. McKay Calgary, Alberta Canada	Chief Operating Officer (age 50)	Officer of the Company.
William R. Peterson Calgary, Alberta Canada	Senior Vice-President, Production, Drilling and Completions (age 45)	Officer of the Company.
Douglas A. Proll Calgary, Alberta Canada	Chief Financial Officer and Senior Vice-President, Finance (age 61)	Officer of the Company.
Scott G. Stauth Calgary, Alberta Canada	Senior Vice-President, Operations Field, Facilities and Pipelines (age 46)	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 57)	Officer of the Company.
Jeffrey W. Wilson Calgary, Alberta Canada	Senior Vice-President, Exploration (age 59)	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 were elected to the Board at the last Annual and General Meeting of Shareholders held on May 5, 2011.

As at December 31, 2011, the directors and executive officers of the Company, as a group, beneficially owned or controlled or directed, directly or indirectly, in the aggregate, approximately 4.3% of the total outstanding common shares (approximately 5.5% 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).

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LEGAL PROCEEDINGS AND REGULATORY ACTIONS

From timeto time, Canadian Natural is the subject of litigation arising out of the Company's normal course of 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.

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 Investor Services LLC 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 6, 2012 in respect of the Company's consolidated financial statements as at December 31, 2011, December 31, 2010, and January 1, 2010, and for each of the years in the two year period ended December 31, 2011 and the Company's internal control over financial reporting as at December 31, 2011. 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.

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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. Faithfull, 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.

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 2011 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 as well as other audit services provided in connection with statutory and regulatory filings; (ii) audit related services including debt covenant compliance, pension assets and Crown Royalty Statements; (iii) tax services related to expatriate personal tax and compliance and other corporate tax return matters; and (iv) non-audit services related to accessing resource materials through PwC's accounting literature library.

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Fees accrued to PwC are shown in the table below.

Auditor service	2011	2010
Audit fees	$2,696,000	$3,001,500
Audit related fees	175,000	169,000
Tax fees	156,000	149,000
All other fees	9,000	54,100
	$3,036,000	$3,373,600

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.comand 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 Special Meeting and Information Circular dated March 16, 2012 in connection with the Annual and Special Meeting of Shareholders of Canadian Natural to be held on May 3, 2012 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, 2011 found on pages 17 to 54, 55 to 96 and 97 to 103 respectively, of the 2011 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, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, 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, 2011 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 13, 2012.	Canada and USA	$0	$44,108	$672	$44,780
Sproule International Limited	Sproule evaluated the P&NG Reserves as reported February 13,	United Kingdom and Offshore Africa	$0	$12,235	$0	$12,235

	2012.					
GLJ Petroleum Consultants Ltd.	GLJ evaluated the oil sands mining properties as reported February 13, 2012.	Canada	$0	$24,237	$0	$24,237
Totals			$0	$80,580	$672	$81,252

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, consistently applied. 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.

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

Sproule Associates Limited
Calgary, Alberta, Canada,
March 5, 2012

Original Signed By

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

Original Signed By

SIGNED "NORA T. STEWART"
Nora T. Stewart, P.Eng.
Manager, Engineering and Partner

Original Signed By

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

Sproule International Limited
Calgary, Alberta, Canada,
March 5, 2012

Original Signed By

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

Original Signed By

SIGNED "PHIL W. PANTELLA"
P.W. (Phil) Pantella, P.Eng.
Manager, Engineering and Partner

Original Signed By

SIGNED "GREG D. ROBINSON"
Greg D. Robinson, P.Eng.
Vice-President, International

GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada,
March 5, 2012

Original Signed By

SIGNED "JAMES H. WILLMON"
James H. Willmon, P.Eng.
Vice-President, Corporate Evaluations

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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, 2011, 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 "CHRISTOPHER L. FONG"
Christopher L. Fong
Independent Director and Member of
the Reserve Committee

Dated this 5th day of March, 2012

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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.

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

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

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

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

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

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

III Audit Committee Duties and Responsibilities

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

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

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

c. to ensure that the management of the Corporation has 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,

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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.

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 Committee.

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 International Financial Reporting Standards 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 2011 consolidated financial statements and its internal control over financial reporting as at December 31, 2011; and

the Company's 2010 consolidated financial statements.

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 6, 2012

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, 2011. 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, 2011, 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 6, 2012

Independent Auditor's Report

To the Shareholders of Canadian Natural Resources Limited

We have completed the integrated audits of Canadian Natural Resources Limited's 2011 consolidated financial statements and its internal control over financial reporting as at December 31, 2011 and an audit of its 2010 consolidated financial statements. 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, which comprise the consolidated balance sheets as at December 31, 2011, December 31, 2010 and January 1, 2010 and the consolidated statements of earnings, comprehensive income, changes in equity and cash flows for each of the years in the two year period ended December 31, 2011, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

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 International Financial Reporting Standards as issued by the International Accounting Standards Board 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.

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, 2011, December 31, 2010 and January 1, 2010 and its financial performance and cash flows for each of the years in the two year period ended December 31, 2011 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

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, 2011, 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 generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the financial statements.

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, 2011 based on criteria established in Internal Control - Integrated Framework issued by COSO.

/s/ PricewaterhouseCoopers
LLP

Chartered Accountants

Calgary, Alberta, Canada
March 6, 2012

Consolidated Balance Sheets

As at (millions of Canadian dollars)	Note	December 31 2011	December 31 2010	January 1 2010
ASSETS				
Current assets				
Cash and cash equivalents		$34	$22	$13
Accounts receivable		2,077	1,481	1,148
Inventory	4	550	477	438
Prepaids and other		120	129	146
		2,781	2,109	1,745
Exploration and evaluation assets	5	2,475	2,402	2,293
Property, plant and equipment	6	41,631	38,429	37,018
Other long-term assets	7	391	14	6
		$47,278	$42,954	$41,062
LIABILITIES				
Current liabilities				
Accounts payable		$526	$274	$240
Accrued liabilities		2,347	1,735	1,430
Current income tax liabilities		347	430	94
Current portion of long-term debt	8	359	397	400
Current portion of other long-term liabilities	9	455	870	854
		4,034	3,706	3,018
Long-term debt	8	8,212	8,088	9,259
Other long-term liabilities	9	3,913	3,004	2,485
Deferred income tax liabilities	11	8,221	7,788	7,462
		24,380	22,586	22,224
SHAREHOLDERS' EQUITY				
Share capital	12	3,507	3,147	2,834
Retained earnings		19,365	17,212	15,927
Accumulated other comprehensive income	13	26	9	77
		22,898	20,368	18,838
		$47,278	$42,954	$41,062

Commitments and contingencies (note 18)

Approved by the Board of Directors on March 6, 2012

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)	Note		2011		2010
Product sales		$	15,507	$	14,322
Less : royalties			(1,715)		(1,421)
Revenue			13,792		12,901
Expenses					
Production			3,671		3,449
Transportation and blending			2,327		1,783
Depletion, depreciation and amortization	6		3,604		4,120
Administration			235		211
Share-based compensation	9		(102)		203
Asset retirement obligation accretion	9		130		123
Interest and other financing costs	16		373		448
Risk management activities	17		(27)		(134)
Foreign exchange loss (gain)			1		(163)
Horizon asset impairment provision	10		396		–
Insurance recovery – property damage	10		(393)		–
Insurance recovery – business interruption	10		(333)		–
			9,882		10,040
Earnings before taxes			3,910		2,861
Current income tax expense	11		860		789
Deferred income tax expense	11		407		399
Net earnings		$	2,643	$	1,673
Net earnings per common share					
Basic	15	$	2.41	$	1.54
Diluted	15	$	2.40	$	1.53

Consolidated Statements of Comprehensive Income

For the years ended December 31

(millions of Canadian dollars)	2011	2010
Net earnings	$2,643	$1,673
Net change in derivative financial instruments designated as cash flow hedges		
Unrealized loss, net of taxes of $5 million (2010 – $13 million)	(23)	(40)
Reclassification to net earnings, net of taxes of $17 million (2010 – $1 million)	52	(4)
	29	(44)
Foreign currency translation adjustment		
Translation of net investment	(12)	(24)
Other comprehensive income (loss), net of taxes	17	(68)
Comprehensive income	$2,660	$1,605

Consolidated Statements of Changes in Equity

For the years ended December 31 (millions of Canadian dollars)	Note	2011	2010
Share capital	12		
Balance – beginning of year		$3,147	$2,834
Issued upon exercise of stock options		255	170
Previously recognized liability on stock options exercised for common shares		115	149
Purchase of common shares under Normal Course Issuer Bid		(10)	(6)
Balance – end of year		3,507	3,147
Retained earnings			
Balance – beginning of year		17,212	15,927
Net earnings		2,643	1,673
Purchase of common shares under Normal Course Issuer Bid	12	(94)	(62)
Dividends on common shares	12	(396)	(326)
Balance – end of year		19,365	17,212
Accumulated other comprehensive income	13		
Balance – beginning of year		9	77
Other comprehensive income (loss), net of taxes		17	(68)
Balance – end of year		26	9
Shareholders' equity		$22,898	$20,368

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Consolidated Statements of Cash Flows

For the years ended December 31 (millions of Canadian dollars)	Note	2011	2010
Operating activities			
Net earnings		$ 2,643	$ 1,673
Non-cash items			
Depletion, depreciation and amortization		3,604	4,120
Share-based compensation		(102)	203
Asset retirement obligation accretion		130	123
Unrealized risk management gain		(128)	(24)
Unrealized foreign exchange loss (gain)		215	(161)
Realized foreign exchange gain on repayment of US dollar debt securities		(225)	–
Deferred income tax expense		407	399
Horizon asset impairment provision	6, 10	396	–
Insurance recovery – property damage	10	(393)	–
Other		(55)	(8)
Abandonment expenditures		(213)	(179)
Net change in non-cash working capital	19	(36)	136
		6,243	6,282
Financing activities			
Repayment of bank credit facilities, net		(647)	(472)
Repayment of medium-term notes		–	(400)
Issue of US dollar debt securities, net		621	–
Issue of common shares on exercise of stock options		255	170
Purchase of common shares under Normal Course Issuer Bid		(104)	(68)
Dividends on common shares		(378)	(302)
Net change in non-cash working capital	19	(15)	(12)
		(268)	(1,084)
Investing activities			
Expenditures on exploration and evaluation assets and property, plant and equipment	19	(6,201)	(5,335)
Investment in other long-term assets		(321)	–
Net change in non-cash working capital	19	559	146
		(5,963)	(5,189)
Increase in cash and cash equivalents		12	9
Cash and cash equivalents – beginning of year		22	13
Cash and cash equivalents – end of year		$ 34	$ 22
Interest paid		$ 456	$ 471
Income taxes paid		$ 706	$ 213

Supplemental disclosure of cash flow information (note 19)

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. 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, Gabon, and South Africa in Offshore Africa.

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

Within Western Canada, the Company maintains certain midstream activities that include pipeline operations and an electricity co-generation system.

The Company was incorporated in Alberta, Canada. The address of its registered office is 2500, 855-2 Street S.W., Calgary, Alberta.

In 2010, the Canadian Institute of Chartered Accountants ("CICA") Handbook was revised to incorporate International Financial Reporting Standards ("IFRS") and require publicly accountable enterprises to apply IFRS effective for years beginning on or after January 1, 2011. The 2011 fiscal year is the first year in which the Company has prepared its consolidated financial statements in accordance with IFRS as issued by the International Accounting Standards Board.

The accounting policies adopted by the Company under IFRS are set out below and are based on IFRS issued and outstanding as at December 31, 2011. Subject to certain transition elections disclosed in note 22, the Company has consistently applied the same accounting policies in its opening IFRS balance sheet at January 1, 2010 and throughout all periods presented, as if these policies had always been in effect.

Comparative information for 2010 has been restated from Canadian Generally Accepted Accounting Principles ("Canadian GAAP") to comply with IFRS. In these consolidated financial statements, Canadian GAAP refers to Canadian GAAP before the adoption of IFRS. Note 22 discloses the impact of the transition to IFRS on the Company's reported financial position, net earnings and cash flows, including the nature and effect of significant changes in accounting policies from those used in the Company's Canadian GAAP consolidated financial statements for the year ended December 31, 2010.

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements have been prepared under the historical cost convention, unless otherwise required.

The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and wholly owned partnerships.

Certain of the Company's activities are conducted through joint ventures. Where the Company has a direct ownership interest in jointly controlled assets, the assets, liabilities, revenue and expenses related to the jointly controlled assets are included in the consolidated financial statements in proportion to the Company's interest. Where the Company has an interest in jointly controlled entities, it uses the equity method of accounting. Under the equity method, the

Company's investment is initially recognized at cost and subsequently adjusted for the Company's share of the jointly controlled entity's income or loss, less dividends received. Unrealized gains and losses on transactions between the Company and the jointly controlled entity are eliminated.

(B) 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 in the consolidated balance sheets.

(C) INVENTORY

Inventory is primarily comprised of product inventory and materials and supplies. Product inventory includes crude oil held for sale, pipeline linefill and crude oil stored in floating production, storage and offloading vessels. Inventories are carried at the lower of cost and net realizable value. Cost consists of purchase costs, direct production costs, directly attributable overhead and depletion, depreciation and amortization and is determined on a first-in, first-out basis. Net realizable value for product inventory is determined by reference to forward prices, and for materials and supplies is based on current market prices as at the date of the consolidated balance sheets.

(D) EXPLORATION AND EVALUATION ASSETS

Exploration and evaluation ("E&E") assets consist of the Company's crude oil and natural gas exploration projects that are pending the determination of proved reserves.

E&E costs are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E costs do not include general prospecting or evaluation costs incurred prior to having obtained the legal rights to explore an area. These costs are recognized immediately in net earnings.

Once the technical feasibility and commercial viability of E&E assets are determined and a development decision is made by management, the E&E assets are tested for impairment upon reclassification to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when proved reserves are determined to exist.

E&E assets are also tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of Cash Generating Units ("CGUs"), aggregated at the segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks.

(E) PROPERTY, PLANT AND EQUIPMENT

Exploration and Production

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. When significant components of an item of property, plant and equipment, including crude oil and natural gas interests, have different useful lives, they are accounted for separately.

The cost of an asset comprises its acquisition, construction and development costs, costs directly attributable to bringing the asset into operation, the estimate of any asset retirement costs, and applicable borrowing costs. Property acquisition costs are comprised of the aggregate amount paid and the fair value of any other consideration given to acquire the asset. The capitalized value of a finance lease is also included in property, plant and equipment.

The cost of property, plant and equipment at January 1, 2010, the date of transition to IFRS, was determined as described in note 22.

Crude oil and natural gas properties are depleted using the unit-of-production method over proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop proved reserves.

Oil Sands Mining and Upgrading

Capitalized costs for the Oil Sands Mining and Upgrading segment are reported separately from the Company's North America Exploration and Production segment. Capitalized costs include property acquisition, construction and development costs, the estimate of any asset retirement costs, and applicable borrowing costs.

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 Horizon proved reserves or productive capacity, respectively. Other equipment is depreciated on a straight-line basis over its estimated useful life ranging from 2 to 15 years.

Midstream and head office

The Company capitalizes all costs that expand the capacity or extend the useful life of the assets. Midstream assets are depreciated on a straight-line basis over their estimated useful lives ranging from 5 to 30 years. Head office assets are amortized on a declining balance basis.

Useful lives

The expected useful lives of property, plant and equipment are reviewed on an annual basis, with changes in useful lives accounted for prospectively.

Derecognition

An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is recognized in net earnings.

Major maintenance expenditures

Inspection costs associated with major maintenance turnarounds are capitalized and amortized over the period to the next major maintenance turnaround. All other maintenance costs are expensed as incurred.

Impairment

The Company assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low benchmark commodity prices for an extended period of time, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If any such indication of impairment exists, the Company performs an impairment test related to the assets. Individual assets are grouped for impairment assessment purposes into CGU's, which are the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. A CGU's recoverable amount is the higher of its fair value less costs to sell and its value in use. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount.

In subsequent periods, an assessment is made at each reporting date to determine whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is re-estimated and the net carrying amount of the asset is increased to its revised recoverable amount. The recoverable amount cannot exceed the carrying amount that would have been determined, net of depletion, had no impairment loss been recognized for the asset in prior periods. Such reversal is recognized in net earnings. After a reversal, the depletion charge is adjusted in future periods to allocate the asset's revised carrying amount over its remaining useful life.

(F) BUSINESS COMBINATIONS

Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed in a business combination are recognized at their fair value at the date of the acquisition.

(G) OVERBURDEN REMOVAL COSTS

Overburden removal costs incurred during the initial development of a mine are capitalized to property, plant and equipment. Overburden removal costs incurred during the production of a mine are included in the cost of inventory, unless the overburden removal activity has resulted in a probable inflow of future economic benefits to the Company, 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.

(H) CAPITALIZED BORROWING COSTS

Borrowing costs attributable to the acquisition, construction or production of qualifying assets are capitalized to the cost of those assets until such time as the assets are substantially available for their intended use. Qualifying assets are comprised of those significant assets that require a period greater than one year to be available for their intended use. All other borrowing costs are recognized in net earnings.

(I) LEASES

Finance leases, which transfer substantially all of the risks and rewards incidental to ownership of the leased item to the Company, are capitalized at the commencement of the lease term at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term. Operating lease payments are recognized in net earnings over the lease term.

(J) ASSET RETIREMENT OBLIGATIONS

The Company provides for asset retirement obligations on all of its property, plant and equipment based on current legislation and industry operating practices. Provisions for asset retirement obligations related to property, plant and equipment are recognized as a liability in the period in which they are incurred. Provisions are measured at the present value of management's best estimate of expenditures required to settle the present obligation at the date of the balance sheet. Subsequent to the initial measurement, the obligation is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes due to discount rates or the estimated future cash flows are capitalized to or derecognized from property, plant, and equipment. Actual costs incurred upon settlement of the asset retirement obligation are charged against the provision.

(K) FOREIGN CURRENCY TRANSLATION

(i) Functional and presentation currency

Items included in the financial statements of the Company's subsidiary companies and partnerships are measured using the currency of the primary economic environment in which the subsidiary operates (the "functional currency"). The consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency.

The assets and liabilities of subsidiaries that have a functional currency different from that of the Company are translated into Canadian dollars at the closing rate at the date of the balance sheet, and revenue and expenses are translated at the average rate for the period. Cumulative foreign currency translation adjustments are recognized in other comprehensive income.

When the Company disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the foreign currency gains or losses accumulated in other comprehensive income related to the foreign operation are recognized in net earnings.

(ii) Transactions and balances

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of foreign currency transactions and from the translation at balance sheet date exchange rates of monetary assets and liabilities denominated in currencies other than the functional currency of the Company or its subsidiaries are recognized in net earnings.

(L) REVENUE RECOGNITION AND COSTS OF GOODS SOLD

Revenue from the sale 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 represents the Company’s share net of 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 Africa is shared under the terms of various Production Sharing Contracts (“PSCs”). Product sales 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) INCOME TAX

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences in the carrying amount of assets and liabilities in the consolidated financial statements and their respective tax bases.

Deferred income tax assets and liabilities are calculated using the substantively enacted income tax rates that are expected to apply when the asset or liability is recovered. Deferred income tax assets or liabilities are not recognized when they arise on the initial recognition of an asset or liability in a transaction (other than in a business combination) that, at the time of the transaction, affects neither accounting nor taxable profit. Deferred income tax assets or liabilities are also not recognized on possible future distributions of retained earnings of subsidiaries where the timing of the distribution can be controlled by the Company and it is probable that a distribution will not be made in the foreseeable future, or when distributions can be made without incurring income taxes.

Deferred income tax assets for deductible temporary differences and tax loss carryforwards are recognized to the extent that it is probable that future taxable profits will be available against which the temporary differences or tax loss carryforwards can be utilized. The carrying amount of deferred income tax assets is reviewed at each reporting date, and is reduced if it is no longer probable that sufficient future taxable profits will be available against which the temporary differences or tax loss carryforwards can be utilized.

Current income tax is calculated based on net earnings for the period, adjusted for items that are non-taxable or taxed in different periods, using income tax rates that are substantively enacted at each reporting date.

Income taxes are recognized in net earnings or other comprehensive income, consistent with the items to which they relate.

(O) SHARE-BASED COMPENSATION

The Company’s Stock Option Plan (the “Option Plan”) provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered. The liability for awards granted to employees is initially measured based on the grant date fair value of the awards and the number of awards expected to vest. The awards are re-measured each reporting period for subsequent changes in the fair value of the liability. Fair value is determined using the Black-Scholes valuation model. Expected volatility is estimated based on historic results. 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 the employee and any previously recognized liability associated with the stock options are recorded as share capital.

(P) FINANCIAL INSTRUMENTS

The Company classifies its financial instruments into one of the following categories: fair value through profit or loss; held-to-maturity investments; loans and receivables; and financial liabilities measured at amortized cost. All financial instruments are measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

Fair value through profit or loss financial instruments are subsequently measured at fair value with changes in fair value recognized in net earnings. All other categories of financial instruments are measured at amortized cost using the effective interest method.

Cash, cash equivalents, and 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 measured at amortized cost. Risk management assets and liabilities are classified as fair value through profit or loss.

Financial assets and liabilities are also 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 in respect of financial instruments at fair value through profit or loss are recognized immediately in net earnings. Transaction costs in respect of other financial instruments are included in the initial measurement of the financial instrument.

Impairment of financial assets

At each reporting date, the Company assesses whether there is objective evidence that a financial asset is impaired. If such evidence exists, an impairment loss is recognized.

Impairment losses on financial assets carried at amortized cost including loans and receivables are calculated as the difference between the amortized cost of the loan or receivable and the present value of the estimated future cash flows, discounted using the instrument's original effective interest rate. Impairment losses on financial assets carried at amortized cost are reversed in subsequent periods if the amount of the loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized.

(Q) 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 in the consolidated balance sheets at their estimated fair value as 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's own credit risk is not included in the carrying amount of a risk management liability.

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 and purchases of crude oil and natural gas in order to protect its cash flow for its 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 net earnings in the same period or periods in which the commodity is sold or purchased. The ineffective portion of changes in the fair value of these designated contracts is immediately recognized in risk management activities in net earnings. All changes in the fair value of non-designated crude oil and natural gas commodity price contracts are included in risk management activities in net earnings.

The Company periodically 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 net earnings. Changes in the fair value of non-designated interest rate swap contracts are included in risk management activities in 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 related to the notional principal amounts are included in foreign exchange gains and losses in 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 net earnings. Changes in the fair value of non-designated cross currency swap contracts are included in risk management activities in 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 net earnings in the period in which the underlying hedged items are recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized immediately in net earnings. Realized gains or losses on the termination of financial instruments that have not been designated as hedges are recognized immediately in net earnings.

Upon termination of an interest rate swap designated as a fair value hedge, the interest rate swap is derecognized on the consolidated balance sheets and the related long-term debt hedged is no longer revalued for subsequent 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 long-term debt.

Foreign currency forward contracts are periodically used to manage foreign currency cash 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 gains and losses when realized. Changes in the fair value of foreign currency forward contracts not included as hedges are included in risk management activities and recognized immediately in 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.

(R) 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 foreign operations that do not have a Canadian dollar functional currency. Other comprehensive income is shown net of related income taxes.

(S) PER COMMON SHARE AMOUNTS

The Company calculates basic earnings per share by dividing net earnings by the weighted average number of common shares outstanding during the period. As the Company's Option Plan allows for the settlement of stock options in either cash or shares at the option of the holder, diluted earnings per share is calculated using the more dilutive of cash settlement or share settlement under the treasury stock method.

(T) SHARE CAPITAL

Common shares are classified as equity. Costs directly attributable to the issue of new shares or options are included in equity as a deduction, net of tax, from proceeds. When the Company acquires its own common shares, share capital is reduced by the average carrying value of the shares purchased. The excess of the purchase price over the average carrying value is recognized as a reduction of retained earnings. Shares are cancelled upon purchase.

(U) DIVIDENDS

Dividends on common shares are recognized in the Company's financial statements in the period in which the dividends are approved by the Board of Directors.

2. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

The Company is required to adopt IFRS 9, “Financial Instruments”, effective January 1, 2015, with earlier adoption permitted. IFRS 9 replaces existing requirements included in IAS 39, “Financial Instruments - Recognition and Measurement”. The new standard replaces the multiple classification and measurement models for financial assets and liabilities with a new model that has only two categories: amortized cost and fair value through profit and loss. Under IFRS 9, fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income.

In May 2011, the IASB issued the following new accounting standards, which are required to be adopted effective January 1, 2013:

- IFRS 10 “Consolidated Financial Statements” replaces IAS 27 “Consolidated and Separate Financial Statements” (IAS 27 still contains guidance for Separate Financial Statements) and Standing Interpretations Committee (“SIC”) 12 “Consolidation – Special Purpose Entities”. IFRS 10 establishes the principles for the presentation and preparation of consolidated financial statements. The standard defines the principle of control and establishes control as the basis for consolidation, as well as providing guidance on how to apply the control principle to determine whether an investor controls an investee.

- IFRS 11 “Joint Arrangements” replaces IAS 31 “Interests in Joint Ventures” and SIC 13 “Jointly Controlled Entities – Non-Monetary Contributions by Venturers”. The new standard defines two types of joint arrangements, joint operations and joint ventures, and prescribes the accounting treatment for each type of joint arrangement – recognition of the proportionate interest in the assets, liabilities, revenues and expenses; and equity accounting, respectively. There is no longer a choice of the accounting method.

- IFRS 12 “Disclosure of Interests in Other Entities”. The standard includes disclosure requirements for investments in subsidiaries, joint arrangements, associates and unconsolidated structured entities. This standard does not impact the Company’s accounting for investments in other entities, but will impact the related disclosures.

- IFRS 13 “Fair Value Measurement” provides guidance on how fair value should be applied where its use is already required or permitted by other standards within IFRS. The standard includes a definition of fair value and a single source of fair value measurement and disclosure requirements for use across all IFRSs that require or permit the use of fair value.

In June 2011, the IASB issued amendments to IAS 1 “Presentation of Financial Statements” that require items of other comprehensive income that may be reclassified to net earnings to be grouped together. The amendments also require that items in other comprehensive income and net earnings be presented as either a single statement or two consecutive statements. The standard is effective for fiscal years beginning on or after July 1, 2012.

In October 2011, the IASB issued IFRS Interpretation Committee (“IFRIC”) 20 “Stripping Costs in the Production Phase of a Surface Mine”. The IFRIC requires overburden removal costs during the production phase to be capitalized and depreciated if the Company can demonstrate that probable future economic benefits will be realized, the costs can be reliably measured, and the Company can identify the component of the ore body for which access has been improved. The IFRIC is effective for fiscal periods beginning on or after January 1, 2013.

The Company is currently assessing the impact of these new and amended standards on its consolidated financial statements. The Company does not plan to early adopt the above noted standards.

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3. CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS

The Company has made estimates, assumptions and judgements regarding certain assets, liabilities, revenues and expenses in the preparation of the consolidated financial statements, primarily related to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts. The estimates, assumptions and judgements that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are addressed below.

(a) Crude oil and natural gas reserves

Purchase price allocations, depletion, depreciation and amortization, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. Reserve estimates 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, interpretations and judgements. 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.

(b) Asset retirement obligations

The calculation of asset retirement obligations includes estimates and judgements of the scope, the future costs and the timing of the cash flows to settle the liability, the discount rate used in reflecting the passage of time, and future inflation rates.

(c) Income taxes

The Company is subject to income taxes in numerous legal jurisdictions. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes liabilities for potential tax audit issues based on assessments of whether additional taxes will be due.

(d) Fair value of derivatives and other financial instruments

The fair value of financial instruments that are not traded in an active market is determined using valuation techniques. The Company uses its judgement to select a variety of methods and make assumptions that are primarily based on market conditions existing at the end of each reporting period. The Company uses directly and indirectly observable inputs in measuring the value of financial instruments that are not traded in active markets, including quoted commodity prices and volatility, interest rate yield curves and foreign exchange rates.

(e) Purchase price allocations

Purchase prices related to 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, estimates and judgements regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties. 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 depletion, depreciation, and amortization expense and impairment tests.

(f) Share-based compensation

The Company has made various assumptions in estimating the fair values of the common stock options granted under the Option Plan, including expected volatility, expected exercise behavior and future forfeiture rates. At each period end, stock options outstanding are remeasured for changes in the fair value of the liability.

(g) Identification of CGUs

CGUs are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The classification of assets into CGUs requires significant judgement and interpretations with respect to the integration between assets, the existence of active markets, shared infrastructures, and the way in which management monitors the Company's operations.

(h) Impairment of Assets

The recoverable amount of a CGU or an individual asset has been determined as the higher of the CGU's or the asset's fair value less costs to sell and its value in use. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGU's.

4. INVENTORY

	December 31 2011	December 31 2010	January 1 2010
Product inventory	$328	$286	$245
Materials and supplies	222	187	159
Other	–	4	34
	$550	$477	$438

5. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At January 1, 2010	$2,102	$–	$191	$–	$2,293
Additions	563	6	3	–	572
Transfers to property, plant and equipment	(299)	–	(154)	–	(453)
Foreign exchange adjustments	–	(1)	(9)	–	(10)
At December 31, 2010	2,366	5	31	–	2,402
Additions	309	1	2	–	312
Transfers to property, plant and equipment	(233)	(6)	–	–	(239)
At December 31, 2011	$2,442	$–	$33	$–	$2,475

6. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At January 1, 2010	$ 36,159	$ 3,866	$ 2,666	$ 13,758	$ 284	$ 214	$ 56,947
Additions	4,403	190	254	411	7	18	5,283
Transfers from E&E assets	299	–	154	–	–	–	453
Disposals/ derecognitions	–	(5)	–	–	–	(11)	(16)
Foreign exchange adjustments and other	–	(238)	(146)	–	–	(5)	(389)
At December 31, 2010	40,861	3,813	2,928	14,169	291	216	62,278
Additions	5,026	235	76	1,545	7	18	6,907
Transfers from E&E assets	233	6	–	–	–	–	239
Disposals/ derecognitions (1)	–	–	(29)	(503)	–	–	(532)
Foreign exchange adjustments and other	–	93	69	–	–	–	162
At December 31, 2011	$ 46,120	$ 4,147	$ 3,044	$ 15,211	$ 298	$ 234	$ 69,054
Accumulated depletion and depreciation							
At January 1, 2010	$ 16,427	$ 2,054	$ 1,008	$ 207	$ 81	$ 152	$ 19,929
Expense	2,473	295	298	396	8	13	3,483
Impairment (2)	–	–	637	–	–	–	637
Disposals/ derecognitions	–	(5)	–	–	–	(11)	(16)
Foreign exchange adjustments and other	(5)	(139)	(39)	4	–	(5)	(184)
At December 31, 2010	18,895	2,205	1,904	607	89	149	23,849
Expense	2,826	248	242	266	7	15	3,604
Impairment (1)	–	–	–	396	–	–	396
Disposals/ derecognitions (1)	–	–	(29)	(503)	–	–	(532)
Foreign exchange adjustments and other	–	59	35	10	–	2	106
	$ 21,721	$ 2,512	$ 2,152	$ 776	$ 96	$ 166	$ 27,423

At December 31, 2011							
Net book value							
- at December 31, 2011	$ 24,399	$ 1,635	$ 892	$ 14,435	$ 202	$ 68	$ 41,631
- at December 31, 2010	$ 21,966	$ 1,608	$ 1,024	$ 13,562	$ 202	$ 67	$ 38,429
- at January 1, 2010	$ 19,732	$ 1,812	$ 1,658	$ 13,551	$ 203	$ 62	$ 37,018

(1) During 2011, the Company derecognized certain property, plant and equipment related to the coker fire at Horizon in the amount of $411 million based on estimated replacement cost, net of accumulated depletion and depreciation of $15 million. There was a resulting impairment charge of $396 million. For additional information, refer to note 10.

(2) During 2010, the Company recognized a $637 million impairment relating to the Gabon CGU, in Offshore Africa, which was included in depletion, depreciation and amortization expense. The impairment was based on the difference between the December 31, 2010 net book value of the assets and their recoverable amounts. The recoverable amounts were determined using fair value less costs to sell based on discounted future cash flows of proved and probable reserves using forecast prices and costs.

Development projects not subject to depletion	
At December 31, 2011	$1,443
At December 31, 2010	$934
At January 1, 2010	$1,270

The Company acquired a number of producing crude oil and natural gas assets in the North American Exploration and Production segment for total cash consideration of $1,012 million during the year ended December 31, 2011 (2010 – $1,482 million), net of associated asset retirement obligations of $79 million (2010 – $22 million). Interests in jointly controlled assets were acquired with full tax basis. No working capital or debt obligations were assumed.

During the year ended December 31, 2011, the Company capitalized directly attributable administrative costs of $44 million (2010 – $43 million) in the North Sea and Offshore Africa, related to development activities and $60 million (2010 – $33 million) in North America, primarily related to Oil Sands Mining and Upgrading.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once construction is substantially complete. For the year ended December 31, 2011, pre-tax interest of $59 million was capitalized to property, plant and equipment (2010 – $28 million) using a capitalization rate of 4.7% (2010 – 4.9%).

7. OTHER LONG-TERM ASSETS

	December 31 2011	December 31 2010	January 1 2010
Investment in North West Redwater Partnership	$321	$–	$–
Other	70	14	6
	$391	$14	$6

Other long-term assets include a $321 million investment in the 50% owned North West Redwater Partnership ("Redwater"), of which $97 million was payable to Redwater at December 31, 2011 to fund project development. The investment is accounted for using the equity method. Redwater has entered into an agreement to construct and operate a bitumen upgrader and refinery, which targets to process bitumen for the Company and the Government of Alberta under a 30 year fee-for-service contract. Project development is dependent upon completion of detailed engineering and final project sanction by Redwater and its partners, and approval of the final tolls.

The Company's share of assets and liabilities of Redwater at December 31, 2011 was comprised as follows:

	December 31 2011
Current assets	$108
Non-current assets	$233
Current liabilities	$117
Non-current liabilities	$–

8. LONG-TERM DEBT

	December 31 2011	December 31 2010	January 1 2010
Canadian dollar denominated debt			
Bank credit facilities	$796	$1,436	$1,897
Medium-term notes			
5.50% unsecured debentures due December 17, 2010	–	–	400
4.50% unsecured debentures due January 23, 2013	400	400	400
4.95% unsecured debentures due June 1, 2015	400	400	400
	1,596	2,236	3,097
US dollar denominated debt			
US dollar debt securities			
6.70% due July 15, 2011 (2011 – US$ nil; 2010 – US$400 million)	–	398	419
5.45% due October 1, 2012 (US$350 million)	356	348	366
5.15% due February 1, 2013 (US$400 million)	406	398	419
1.45% due November 14, 2014 (2011 – US$500 million; 2010 – US$ nil)	509	–	–
4.90% due December 1, 2014 (US$350 million)	356	348	366
6.00% due August 15, 2016 (US$250 million)	255	249	262
5.70% due May 15, 2017 (US$1,100 million)	1,119	1,094	1,151
5.90% due February 1, 2018 (US$400 million)	406	398	419
3.45% due November 15, 2021 (2011 – US$500 million; 2010 – US$ nil)	509	–	–
7.20% due January 15, 2032 (US$400 million)	406	398	419
6.45% due June 30, 2033 (US$350 million)	356	348	366
5.85% due February 1, 2035 (US$350 million)	356	348	366
6.50% due February 15, 2037 (US$450 million)	458	447	471
6.25% due March 15, 2038 (US$1,100 million)	1,119	1,094	1,151
6.75% due February 1, 2039 (US$400 million)	406	398	419
Less: original issue discount on US dollar debt securities (1)	(21)	(20)	(22)
	6,996	6,246	6,572
Fair value impact of interest rate swaps on US dollar debt securities (2)	31	47	39
	7,027	6,293	6,611
Long-term debt before transaction costs	8,623	8,529	9,708
Less: transaction costs (1) (3)	(52)	(44)	(49)
	8,571	8,485	9,659
Less: current portion (1) (2)	359	397	400
	$8,212	$8,088	$9,259

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

(2) The carrying amounts of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 were adjusted by $31 million (December 2010 – $47 million; January 2010 – $39 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.

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Bank Credit Facilities

As at December 31, 2011, the Company had in place unsecured bank credit facilities of $4,724 million, comprised of:

- a $200 million demand credit facility;
- a revolving syndicated credit facility of $3,000 million maturing June 2015;
- 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.

During 2011, the $2,230 million revolving syndicated credit facility was increased to $3,000 million and extended to June 2015. Each of the $3,000 million and $1,500 million facilities is 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 may be made by way of pricing referenced to Canadian dollar and US dollar bankers' acceptances, and LIBOR, US base rate and Canadian prime loans.

The Company's weighted average interest rate on bank credit facilities outstanding as at December 31, 2011, was 2.2% (December 31, 2010 – 1.5%), and on long-term debt outstanding for the year ended December 31, 2011 was 4.7% (December 31, 2010 – 4.9%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $436 million, including $127 million related to Horizon and $174 million related to North Sea operations, were outstanding at December 31, 2011.

Medium-Term Notes

In November 2011, 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 2013. If issued, these securities will bear interest as determined at the date of issuance.

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

US Dollar Debt Securities

In July 2011, the Company repaid US$400 million of US dollar debt securities bearing interest at 6.70%.

In November 2011, 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 2013. Subsequently, the Company issued US$1,000 million of unsecured notes under the US base shelf prospectus, comprised of US$500 million of 1.45% unsecured notes due November 2014 and US$500 million of 3.45% unsecured notes due November 2021. Concurrently, the Company entered into cross currency swaps to fix the Canadian dollar interest and principal repayment amounts on the US$500 million of 3.45% unsecured notes due November 2021 at 3.96% and C$511 million (note 17). Proceeds from the securities issued were used to repay bank indebtedness. After issuing these securities, the Company has US$2,000 million remaining on its outstanding US$3,000 million base shelf prospectus, which expires in November 2013. 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
2012	$356
2013	$806
2014	$865
2015	$1,196
2016	$255
Thereafter	$5,135

9. OTHER LONG-TERM LIABILITIES

	December 31 2011	December 31 2010	January 1 2010
Asset retirement obligations	$3,577	$2,624	$2,214
Share-based compensation	432	663	622
Risk management (note 17)	274	485	325
Other	85	102	178
	4,368	3,874	3,339
Less: current portion	455	870	854
	$3,913	$3,004	$2,485

Asset retirement obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 4.6% (December 31, 2010 – 5.1%; January 1, 2010 – 5.8%). A reconciliation of the discounted asset retirement obligations is as follows:

	2011	2010
Balance – beginning of year	$2,624	$2,214
Liabilities incurred	12	12
Liabilities acquired	79	22
Liabilities settled	(213)	(179)
Asset retirement obligation accretion	130	123
Revision of estimates	924	474
Foreign exchange adjustments	21	(42)
Balance – end of year	$3,577	$2,624

Segmented asset retirement obligations

	December 31 2011	December 31 2010	January 1 2010
Exploration and Production			
North America	$1,862	$1,390	$905
North Sea	723	670	630
Offshore Africa	192	137	129
Oil Sands Mining and Upgrading	798	426	549
Midstream	2	1	1
	$3,577	$2,624	$2,214

Share-based compensation

As the Company's Option Plan provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered, a liability for potential cash settlements is recognized. The current portion represents the maximum amount of the liability payable within the next twelve month period if all vested stock options are surrendered for cash settlement.

	2011	2010
Balance – beginning of year	$663	$622
Share-based compensation (recovery) expense	(102)	203
Cash payment for stock options surrendered	(14)	(45)
Transferred to common shares	(115)	(149)
Capitalized to Oil Sands Mining and Upgrading	–	32
Balance – end of year	432	663
Less: current portion	384	623
	$48	$40

The share-based compensation liability of $432 million at December 31, 2011 (2010 – $663 million) was estimated using the Black-Scholes valuation model and the following weighted average assumptions:

	2011	2010
Fair value	$10.84	$16.49
Share price	$38.15	$44.35
Expected volatility	36.94%	33.47%
Expected dividend yield	0.94%	0.68%
Risk free interest rate	1.13%	1.91%
Expected forfeiture rate	4.65%	4.96%
Expected stock option life (1)	4.5 years	4.5 years

(1) At original time of grant

10. HORIZON ASSET IMPAIRMENT PROVISION AND INSURANCE RECOVERY

Due to property damage resulting from a fire in the Horizon primary upgrading coking plant on January 6, 2011, the Company recognized an asset impairment provision in the Oil Sands Mining and Upgrading segment of $396 million, net of accumulated depletion and amortization. Insurance proceeds of $393 million were also recognized, offsetting the property damage. Production resumed in August 2011. As at December 31, 2011, the Company finalized its property damage insurance claim with certain of its insurers. The Company believes that the remaining portion of the property damage insurance claim will be settled without further adjustment.

The Company also maintains business interruption insurance to reduce operating losses related to its ongoing Horizon operations. The Company finalized its business interruption insurance claim for $333 million.

11. INCOME TAXES

The provision for income tax is as follows:

	2011	2010
Current corporate income tax – North America	$315	$431
Current corporate income tax – North Sea	245	203
Current corporate income tax – Offshore Africa	140	64
Current PRT(1) expense – North Sea	135	68
Other taxes	25	23
Current income tax expense	860	789
Deferred corporate income tax expense	412	408
Deferred PRT recovery – North Sea	(5)	(9)
Deferred income tax expense	407	399
Income tax expense	$1,267	$1,188

(1) Petroleum Revenue Tax

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:

	2011	2010
Canadian statutory income tax rate	26.6%	28.1%
Income tax provision at statutory rate	$1,040	$802
Effect on income taxes of:		
UK PRT and other taxes	155	82
Impact of deductible UK PRT and other taxes on corporate income tax	(77)	(30)
Foreign and domestic tax rate differentials	84	15
Non-taxable portion of foreign exchange loss (gain)	6	(17)
Stock options exercised for common shares	(31)	217
Income tax rate and other legislation changes	104	–
Non-deductible Offshore Africa impairment charge	–	130
Other	(14)	(11)
Income tax expense	$1,267	$1,188

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

	December 31 2011	December 31 2010	January 1 2010
Deferred income tax liabilities			
Property, plant and equipment and exploration and evaluation assets	$8,404	$7,719	$7,107
Timing of partnership items	1,065	988	1,127
Unrealized foreign exchange gain on long-term debt	149	194	152
Deferred PRT	74	78	91
	9,692	8,979	8,477
Deferred income tax assets			
Asset retirement obligations	(1,136)	(806)	(695)
Loss carryforwards	(119)	(144)	(84)
Share-based compensation	–	–	(132)
Unrealized risk management activities	(40)	(96)	(74)
Other	(176)	(145)	(30)
	(1,471)	(1,191)	(1,015)
Net deferred income tax liability	$8,221	$7,788	$7,462

Movements in deferred tax liabilities and assets recognized in net earnings during the year were as follows:

	2011	2010
Property, plant and equipment and exploration and evaluation assets	$662	$684
Timing of partnership items	77	(139)
Unrealized foreign exchange (gain) loss on long-term debt	(45)	42
Unrealized risk management activities	44	(8)
Asset retirement obligations	(321)	(127)
Share-based compensation	–	132
Loss carryforwards	25	(60)
Deferred PRT	(5)	(9)
Other	(30)	(116)
	$407	$399

The following table summarizes the movements of deferred income tax liability during the year:

	2011	2010
Balance – beginning of year	$7,788	$7,462
Deferred income tax expense	407	399
Deferred income tax expense (recovery) included in other comprehensive income	12	(14)
Foreign exchange adjustments	20	(59)
Other	(6)	–
Balance – end of year	$8,221	$7,788

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

During 2011, the Canadian Federal government enacted legislation to implement several taxation changes. These changes include a requirement that, beginning in 2012, partnership income must be included in the taxable income of each corporate partner based on the tax year of the partner, rather than the fiscal year of the partnership. The legislation includes a five-year transition provision and has no impact on net earnings.

During 2011, the UK government enacted an increase to the supplementary income tax rate charged on profits from UK North Sea crude oil and natural gas production, increasing the combined corporate and supplementary income tax rate from 50% to 62%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $104 million.

During 2010, deferred income tax expense included a charge of $132 million related to enacted changes in Canada to the taxation of stock options surrendered by employees for cash.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's results of operations, financial position or liquidity.

Deferred income tax assets are recognized for temporary differences to the extent that the realization of the related tax benefit through future taxable profits is probable. The Company did not recognize deferred income tax assets with respect to taxable capital loss carryforwards in excess of $1,000 million in North America, which can be carried forward indefinitely and only applied against future taxable capital gains.

Deferred income tax liabilities have not been recognized on the unremitted net earnings of wholly controlled subsidiaries.The Company is able to control the timing and amount of distributions and no taxes are payable on distributions from these subsidiaries as long as the distributions remain within certain limits.

12. 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

	2011		2010	
Common shares	Number of shares (thousands)	Amount	Number of shares (thousands) (1)	Amount
Balance – beginning of year	1,090,848	$3,147	1,084,654	$2,834
Issued upon exercise of stock options	8,683	255	8,208	170
Previously recognized liability on stock options exercised for common shares	–	115	–	149
Cancellation of common shares	–	–	(14)	–
Purchase of common shares under Normal Course Issuer Bid	(3,071)	(10)	(2,000)	(6)
Balance – end of year	1,096,460	$3,507	1,090,848	$3,147

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

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 6, 2012, the Board of Directors set the Company's regular quarterly dividend at $0.105 per common share (2011 – $0.09 per common share; 2010 – $0.075 per common share).

Normal Course Issuer Bid

In 2011, 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 twelve month period commencing April 6, 2011 and ending April 5, 2012, up to 27,406,131 common shares or 2.5% of the common shares of the Company outstanding at March 25, 2011. During 2011, the Company purchased 3,071,100 common shares (2010 – 2,000,000 common shares) at an average price of $33.68 per common share (2010 – $33.77 per common share), for a total cost of $104 million (2010 – $68 million). Retained earnings were reduced by $94 million (2010 – $62 million), representing the excess of the purchase price of the common shares over their average carrying value.

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 on May 21, 2010. All common share, per common share, and stock option amounts were restated to reflect the common 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 stock option.

The Option Plan is a "rolling 9%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 9% of the common shares outstanding from time to time.

The following table summarizes information relating to stock options outstanding at December 31, 2011 and 2010:

	2011		2010	
	Stock options (thousands)	Weighted average exercise price	Stock options (thousands) (1)	Weighted average exercise price(1)
Outstanding – beginning of year	66,844	$33.31	64,211	$29.27
Granted	19,516	$37.54	16,168	$40.68
Surrendered for cash settlement	(1,124)	$29.84	(2,741)	$21.00
Exercised for common shares	(8,683)	$29.34	(8,208)	$20.66
Forfeited	(3,067)	$35.87	(2,586)	$32.30
Outstanding – end of year	73,486	$34.85	66,844	$33.31
Exercisable – end of year	26,486	$32.13	23,668	$30.64

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

The range of exercise prices of stock options outstanding and exercisable at December 31, 2011 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
$ 22.98 – $24.99	10,180	2.16	$ 23.21	5,486	$ 23.19
$ 25.00 – $29.99	2,300	1.06	$ 28.10	2,079	$ 28.02
$ 30.00 – $34.99	18,034	2.63	$ 33.33	8,507	$ 32.44
$ 35.00 – $39.99	28,650	3.71	$ 36.49	7,697	$ 35.37
$ 40.00 – $44.99	11,782	4.18	$ 42.23	2,064	$ 42.24
$ 45.00 – $46.25	2,540	3.87	$ 45.65	653	$ 46.25
	73,486	3.23	$ 34.85	26,486	$ 32.13

13. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	December 31 2011	December 31 2010	January 1 2010
Derivative financial instruments designated as cash flow hedges	$62	$33	$77
Foreign currency translation adjustment	(36)	(24)	–
	$26	$9	$77

During the next twelve months, $6 million is expected to be reclassified to net earnings from accumulated other comprehensive income.

14. 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 at 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 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's internal targeted range for its debt to book capitalization ratio is 35% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. 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, 2011, the ratio was below the target range at 27%.

Readers are cautioned that the debt to book capitalization ratio is not defined by IFRS and this financial measure may not be comparable to similar measures presented by other companies. Further, there are 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.

	December 31 2011	December 31 2010	January 1 2010
Long-term debt (1)	$8,571	$8,485	$9,659
Total shareholders' equity	$22,898	$20,368	$18,838
Debt to book capitalization	27%	29%	34%

(1) Includes the current portion of long-term debt.

15. NET EARNINGS PER COMMON SHARE

	2011	2010
Weighted average common shares outstanding – basic (thousands of shares)	1,095,582	1,088,096
Effect of dilutive stock options (thousands of shares)	7,000	7,552
Weighted average common shares outstanding – diluted (thousands of shares)	1,102,582	1,095,648
Net earnings	$2,643	$1,673
Net earnings per common share – basic	$2.41	$1.54
– diluted	$2.40	$1.53

For the year ended December 31, 2011, 5,610,000 stock options (2010- 3,338,000) were excluded from the calculation as their effect on per common share amounts was not dilutive.

16. INTEREST AND OTHER FINANCING COSTS

	2011	2010
Interest expense:		
Long-term debt	$450	$485
Other financing costs	(4)	(6)
	446	479
Less: amounts capitalized on qualifying assets	59	28
Total interest and other financing costs	387	451
Interest income:		
Interest income on cash and cash equivalents	(14)	(3)
Total interest income	(14)	(3)
Net interest and other financing costs	$373	$448

17. FINANCIAL INSTRUMENTS

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

	December 31, 2011				
Asset (liability)	Loans and receivables at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$2,077	$–	$–	$–	$2,077
Accounts payable	–	–	–	(526)	(526)
Accrued liabilities	–	–	–	(2,347)	(2,347)
Other long-term liabilities	–	(38)	(236)	(75)	(349)
Long-term debt (1)	–	–	–	(8,571)	(8,571)
	$2,077	$(38)	$(236)	$(11,519)	$(9,716)

	December 31, 2010				
Asset (liability)	Loans and receivables at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$1,481	$–	$–	$–	$1,481
Accounts payable	–	–	–	(274)	(274)
Accrued liabilities	–	–	–	(1,735)	(1,735)
Other long-term liabilities	–	(167)	(318)	(91)	(576)
Long-term debt (1)	–	–	–	(8,485)	(8,485)
	$1,481	$(167)	$(318)	$(10,585)	$(9,589)

	January 1, 2010				
Asset (liability)	Loans and receivables at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$1,148	$–	$–	$–	$1,148
Accounts payable	–	–	–	(240)	(240)
Accrued liabilities	–	–	–	(1,430)	(1,430)
Other long-term liabilities	–	(182)	(143)	(167)	(492)
Long-term debt (1)	–	–	–	(9,659)	(9,659)
	$1,148	$(182)	$(143)	$(11,496)	$(10,673)

(1) Includes the current portion of long-term debt.

The carrying amount 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 other long-term liabilities and fixed rate long-term debt are outlined below:

	December 31, 2011		
	Carrying amount	Fair value	
Liability (1)		Level 1	Level 2
Other long-term liabilities	$ (274)	$ –	$ (274)
Fixed rate long-term debt (2) (3) (4)	(7,775)	(9,120)	–
	$ (8,049)	$ (9,120)	$ (274)

	December 31, 2010		
	Carrying amount	Fair value	
Liability (1)		Level 1	Level 2
Other long-term liabilities	$ (485)	$ –	$ (485)
Fixed rate long-term debt (2) (3) (4)	(7,049)	(7,835)	–
	$ (7,534)	$ (7,835)	$ (485)

	January 1, 2010		
	Carrying amount	Fair value	
Liability (1)		Level 1	Level 2
Other long-term liabilities	$ (325)	$ –	$ (325)
Fixed rate long-term debt (2) (3) (4)	(7,762)	(8,212)	–
	$ (8,087)	$ (8,212)	$ (325)

(1) Excludes financial assets and liabilities where the carrying amount 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 amounts 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 $31 million (December 31, 2010 – $47 million; January 1, 2010 – $39 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.

(4) Includes the current portion of long-term debt.

The following provides a summary of the carrying amounts of derivative contracts held and a reconciliation to the Company's consolidated balance sheets.

Asset (liability)	December 31, 2011	December 31, 2010	January 1, 2010
Derivatives held for trading			
Crude oil price collars	$ (13)	$ (64)	$ (256)
Crude oil put options	–	(83)	–
Natural gas price collars	–	–	72
Interest rate swaps	–	–	11
Foreign currency forward contracts	(25)	(20)	(9)
Cash flow hedges			
Natural gas swaps	–	(49)	–
Cross currency swaps	(236)	(269)	(158)
Fair value hedges			
Interest rate swaps	–	–	15
	$ (274)	$ (485)	$ (325)
Included within:			
Current portion of other long-term liabilities	$ (43)	$ (222)	$ (182)
Other long-term liabilities	(231)	(263)	(143)
	$ (274)	$ (485)	$ (325)

Ineffectiveness arising from cash flow hedges recognized in net earnings for the year ended December 31, 2011 resulted in a loss of $2 million (December 31, 2010 – loss of $1 million).

Risk Management

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

Asset (liability)	2011	2010
Balance – beginning of year	$(485)	$(325)
Net cost of outstanding put options	–	106
Net change in fair value of outstanding derivative financial instruments attributable to:		
Risk management activities	128	24
Interest expense	–	30
Foreign exchange	42	(101)
Other comprehensive income	41	(58)
Settlement of interest rate swaps and other	–	(55)
	(274)	(379)
Add: put premium financing obligations (1)	–	(106)
Balance – end of year	(274)	(485)
Less: current portion	(43)	(222)
	$(231)	$(263)

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

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

	2011	2010
Net realized risk management loss (gain)	$101	$(110)
Net unrealized risk management gain	(128)	(24)
	$(27)	$(134)

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 periodically 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, 2011, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

Sales contracts

	Remaining term			Volume	Weighted average price		Index
Crude oil (1)							
Crude oil price collars (2)	Jan 2012	–	Dec 2012	50,000 bbl/d	US$80.00	– US$134.87	Brent

(1) Subsequent to December 31, 2011, the Company entered into 50,000 bbl/d of US$80 WTI put options for the month of February 2012 for a total cost of US$3 million and 100,000 bbl/d of US$80 WTI put options for the period March to December 2012 for a total cost of US$62 million.

(2) Subsequent to December 31, 2011, the Company entered into an additional 50,000 bbl/d of US$80-US$136.06 Brent collars for the period February to December 2012.

During 2011, US$106 million of put option costs were settled.

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.

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 periodically 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. During 2011, the Company unwound C$200 million of 1.4475% interest rate swaps with an original maturity of February 2012 for nominal consideration. At December 31, 2011, the Company had no interest rate swap contracts outstanding.

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 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, 2011, the Company had the following cross currency swap contracts outstanding:

	Remaining term		Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency						
Swaps(1)	Jan 2012	– Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2012	– May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2012	– Nov 2021	US$500	1.022	3.45%	3.96%
	Jan 2012	– Mar 2038	US$550	1.170	6.25%	5.76%

(1) The cross currency swaps that had been designated as cash flow hedges of US $400 million of 6.70% debt securities were settled, resulting in a realized loss of $9 million.

All cross currency swap derivative financial instruments designated as hedges at December 31, 2011 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2011, the Company had US$2,043 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less.

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, 2011, 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, are limited to the impact of changes in a specified variable applied to financial instruments only 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 cannot be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

	Impact on net earnings	Impact on other comprehensive income
Commodity price risk		
Increase Brent US$1.00/bbl	$(4)	$ –

Decrease Brent US$1.00/bbl	$4	$ –
Interest rate risk		
Increase interest rate 1%	$(5)	$ 16
Decrease interest rate 1%	$5	$ (23)
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$(22)	$ –
Decrease exchange rate by US$0.01	$22	$ –

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, 2011, substantially all of the Company's accounts receivable 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, 2011, the Company had net risk management assets of $nil with specific counterparties related to derivative financial instruments (December 31, 2010 – $nil; January 1, 2010 – $7 million).

The carrying amount of financial assets approximates the maximum credit exposure.

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. The Company believes it has adequate bank credit facilities to provide liquidity to manage fluctuations in the timing of the receipt and/or disbursement of operating cash flows.

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	$ 526	$ –	$ –	$ –
Accrued liabilities	$ 2,347	$ –	$ –	$ –
Risk management	$ 43	$ 40	$ 120	$ 71
Other long-term liabilities	$ 28	$ 13	$ 34	$ –
Long-term debt (1)	$ 356	$ 806	$ 2,316	$ 5,135

(1) Long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs.

18. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2012	2013	2014	2015	2016	Thereafter
Product transportation and pipeline	$ 247	$ 210	$ 199	$ 185	$ 123	$ 888
Offshore equipment operating leases	$ 118	$ 101	$ 100	$ 82	$ 53	$ 119
Office leases	$ 30	$ 33	$ 34	$ 32	$ 33	$ 305
Other	$ 288	$ 158	$ 88	$ 24	$ 2	$ 8

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.

19. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	2011	2010
Changes in non-cash working capital		
Accounts receivable (1)	$(198)	$(321)
Inventory	(72)	(35)
Prepaids and other	(17)	18
Accounts payable	251	36
Accrued liabilities	627	232
Current income tax liabilities	(83)	340
Net changes in non-cash working capital	$508	$270
Relating to:		
Operating activities	$(36)	$136
Financing activities	(15)	(12)
Investing activities	559	146
	$508	$270

	2011	2010
Expenditures on exploration and evaluation assets	$312	$572
Expenditures on property, plant and equipment	5,895	4,771
Net proceeds on sale of property, plant and equipment	(6)	(8)
Net expenditures on exploration and evaluation assets and property, plant and equipment	$6,201	$5,335

(1) Adjusted for the working capital impact of insurance recoveries related to property damage.

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20. SEGMENTED INFORMATION

The Company's exploration and production activities are conducted in three geographic segments: North America, North Sea and Offshore 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 activities are reported in a separate segment from exploration and production activities as the bitumen will be recovered through mining operations.

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

Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. Segment revenues and segment results include transactions between business segments. These transactions and any unrealized profits and losses are eliminated on consolidation, unless unrealized losses provide evidence of an impairment of the asset transferred. Sales to external customers are based on the location of the seller.

Operating segments are reported in a manner consistent with the internal reporting provided to senior management.

	Exploration and Production					
	North America		North Sea		Offshore Africa	
	2011	2010	2011	2010	2011	2010
Segmented product sales	$11,806	$9,713	$1,224	$1,058	$946	$884
Less: royalties	(1,538)	(1,267)	(3)	(2)	(114)	(62)
Segmented revenue	10,268	8,446	1,221	1,056	832	822
Segmented expenses						
Production	1,933	1,675	412	387	186	167
Transportation and blending	2,301	1,761	13	8	1	1
Depletion, depreciation and amortization	2,840	2,484	249	297	242	935
Asset retirement obligation accretion	70	52	33	36	7	7
Realized risk management activities	101	(110)	–	–	–	–
Horizon asset impairment provision	–	–	–	–	–	–
Insurance recovery – property damage (note 10)	–	–	–	–	–	–
Insurance recovery – business interruption (note 10)	–	–	–	–	–	–
Total segmented expenses	7,245	5,862	707	728	436	1,110
Segmented earnings (loss) before the following	$3,023	$2,584	$514	$328	$396	$(288)
Non–segmented expenses						
Administration						
Share-based compensation						
Interest and other financing costs						

Unrealized risk management activities
Foreign exchange loss (gain)
Total non–segmented expenses
Earnings before taxes
Current income tax expense
Deferred income tax expense
Net earnings

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	Oil Sands Mining and Upgrading		Midstream		Inter–segment elimination and other		Total	
	2011	2010	2011	2010	2011	2010	2011	2010
Segmented product sales	$ 1,521	$ 2,649	$ 88	$ 79	$ (78)	$ (61)	$ 15,507	$ 14,322
Less: royalties	(60)	(90)	–	–	–	–	(1,715)	(1,421)
Segmented revenue	1,461	2,559	88	79	(78)	(61)	13,792	12,901
Segmented expenses								
Production	1,127	1,208	26	22	(13)	(10)	3,671	3,449
Transportation and blending	62	61	–	–	(50)	(48)	2,327	1,783
Depletion, depreciation and amortization	266	396	7	8	–	–	3,604	4,120
Asset retirement obligation accretion	20	28	–	–	–	–	130	123
Realized risk management activities	–	–	–	–	–	–	101	(110)
Horizon asset impairment provision	396	–	–	–	–	–	396	–
Insurance recovery – property damage (note 10)	(393)	–	–	–	–	–	(393)	–
Insurance recovery – business interruption (note 10)	(333)	–	–	–	–	–	(333)	–
Total segmented expenses	1,145	1,693	33	30	(63)	(58)	9,503	9,365
Segmented earnings (loss) before the following	$ 316	$ 866	$ 55	$ 49	$ (15)	$ (3)	4,289	3,536
Non–segmented expenses								
Administration							235	211
Share-based compensation							(102)	203
Interest and other financing costs							373	448
Unrealized risk management activities							(128)	(24)
Foreign exchange loss (gain)							1	(163)
Total non–segmented expenses							379	675
Earnings before taxes							3,910	2,861

Current income tax expense	860	789
Deferred income tax expense	407	399
Net earnings	$ 2,643	$ 1,673

Capital Expenditures (1)

	2011			2010		
	Net expenditures	Non cash and fair value changes(2)	Capitalized costs	Net expenditures	Non cash and fair value changes(2)	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America	$309	$(233)	$76	$563	$(299)	$264
North Sea	1	(6)	(5)	6	–	6
Offshore Africa	2	–	2	3	(154)	(151)
	$312	$(239)	$73	$572	$(453)	$119
Property, plant and equipment						
Exploration and Production						
North America	$4,427	$832	$5,259	$3,806	$896	$4,702
North Sea	226	15	241	143	42	185
Offshore Africa	31	16	47	246	162	408
	4,684	863	5,547	4,195	1,100	5,295
Oil Sands Mining and Upgrading (3) (4)	1,182	(140)	1,042	543	(132)	411
Midstream	5	2	7	7	–	7
Head office	18	–	18	18	(11)	7
	$5,889	$725	$6,614	$4,763	$957	$5,720

(1) This table provides a reconciliation of capitalized costs and does not include the impact of accumulated depletion and depreciation.

(2) Asset retirement obligations, deferred income tax adjustments related to differences between carrying amounts and tax values, transfers of exploration and evaluation assets, and other fair value adjustments.

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

(4) During 2011, the Company derecognized certain property, plant and equipment related to the coker fire at Horizon in the amount of $411 million. This amount has been included in non cash and fair value changes.

Segmented Assets

	2011	2010
Exploration and Production		
North America	$28,554	$25,486
North Sea	1,809	1,759
Offshore Africa	1,070	1,263
Other	23	15
Oil Sands Mining and Upgrading	15,433	14,026
Midstream	321	338
Head office	68	67
	$47,278	$42,954

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21. REMUNERATION OF DIRECTORS AND SENIOR MANAGEMENT

Remuneration of non-management directors

	2011	2010
Fees earned	$2	$2

Remuneration of senior management (1)

	2011	2010
Salary	$2	$2
Common stock option based awards	18	30
Annual incentive plans	2	3
Long-term incentive plans	8	16
Other compensation	–	2
	$30	$53

(1) Senior management identified above are consistent with the disclosure on Named Executive Officers provided in the Company's Information Circular to shareholders.

22. TRANSITION TO IFRS

The effect of the Company's transition to IFRS, described in note 1, is summarized below:

(i) Transition elections

The Company has applied the following transition exceptions and exemptions to full retrospective application of IFRS as described below:

	Note
Deemed cost of property, plant and equipment	(A)
Leases	(B)
Share-based compensation	(C)
Borrowing costs	(D)
Asset retirement obligations	(E)
Cumulative translation adjustment	(F)
Business combinations	(G)

(ii) Transition adjustments

The Company has recorded the following transition adjustments upon adoption of IFRS:

	Note
Risk management	(H)
Petroleum Revenue Tax	(I)
UK deferred income tax liabilities	(J)
Reclassification of current portion of deferred income tax	(K)
Horizon major maintenance costs	(L)
Long-term debt	(M)

Reconciliations of the Consolidated Balance Sheets

(millions of Canadian dollars)		December 31, 2010			January 1, 2010		
	Note	Canadian GAAP	Adj	IFRS	Canadian GAAP	Adj	IFRS
ASSETS							
Current assets							
Cash and cash equivalents		$ 22	$ –	$ 22	$ 13	$ –	$ 13
Accounts receivable		1,481	–	1,481	1,148	–	1,148
Inventory	(A)	481	(4)	477	438	–	438
Prepaids and other		129	–	129	146	–	146
Deferred income tax assets	(K)	59	(59)	–	146	(146)	–
		2,172	(63)	2,109	1,891	(146)	1,745
Exploration and evaluation assets	(A)	–	2,402	2,402	–	2,293	2,293
Property, plant and equipment	(A)(C)(E)(L)	40,472	(2,043)	38,429	39,115	(2,097)	37,018
Other long-term assets		25	(11)	14	18	(12)	6
		$ 42,669	$ 285	$ 42,954	$ 41,024	$ 38	$ 41,062
LIABILITIES							
Current liabilities							
Accounts payable		$ 274	$ –	$ 274	$ 240	$ –	$ 240
Accrued liabilities		1,733	2	1,735	1,428	2	1,430
Current income tax liabilities		430	–	430	94	–	94
Current portion of long-term debt	(M)	–	397	397	–	400	400
Current portion of other long-term liabilities	(C)	719	151	870	643	211	854
		3,156	550	3,706	2,405	613	3,018
Long-term debt	(H)(M)	8,499	(411)	8,088	9,658	(399)	9,259
Other long-term liabilities	(C)(E)(H)	2,130	874	3,004	1,848	637	2,485
Deferred income tax liabilities	(I)(J)(K)	7,899	(111)	7,788	7,687	(225)	7,462
		21,684	902	22,586	21,598	626	22,224
SHAREHOLDERS' EQUITY							
Share capital		3,147	–	3,147	2,834	–	2,834
Retained earnings		18,005	(793)	17,212	16,696	(769)	15,927
Accumulated other comprehensive (loss) income	(F)(H)	(167)	176	9	(104)	181	77

	20,985	(617)	20,368	19,426	(588)	18,838
	$ 42,669	$ 285	$ 42,954	$ 41,024	$ 38	$ 41,062

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Reconciliation of the Consolidated Statements of Earnings

For the year ended December 31 (millions of Canadian dollars, except per common share amounts)		2010		
	Note	Canadian GAAP	Adj	IFRS
Product sales		$ 14,322	$ –	$ 14,322
Less: royalties		(1,421)	–	(1,421)
Revenue		12,901	–	12,901
Expenses				
Production	(A)	3,447	2	3,449
Transportation and blending		1,783	–	1,783
Depletion, depreciation and amortization	(A)(E)(L)	4,036	84	4,120
Administration	(A)	210	1	211
Share-based compensation	(C)	294	(91)	203
Asset retirement obligation accretion	(E)	107	16	123
Interest and other financing costs	(H)	449	(1)	448
Risk management activities	(H)	(121)	(13)	(134)
Foreign exchange gain	(J)	(182)	19	(163)
		10,023	17	10,040
Earnings before taxes		2,878	(17)	2,861
Taxes other than income tax		119	(119)	–
Current income tax expense		698	91	789
Deferred income tax expense	(I)(J)	364	35	399
Net earnings		$ 1,697	$ (24)	$ 1,673
Net earnings per common share				
Basic		$ 1.56	$ (0.02)	$ 1.54
Diluted		$ 1.56	$ (0.03)	$ 1.53

Reconciliation of the Consolidated Statements of Comprehensive Income

For the year ended December 31 (millions of Canadian dollars)		2010		
	Note	Canadian GAAP	Adj	IFRS
Net earnings		$ 1,697	$ (24)	$ 1,673
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized loss	(H)	(35)	(18)	(53)
Income tax		11	2	13
Unrealized loss, net of tax		(24)	(16)	(40)
Reclassification to net earnings		(5)	–	(5)

Income tax	1	–	1
Reclassification to net earnings, net of taxes	(4)	–	(4)
	(28)	(16)	(44)
Foreign currency translation adjustment			
Translation of net investment	(35)	11	(24)
Other comprehensive loss, net of taxes	(63)	(5)	(68)
Comprehensive income	$ 1,634	$ (29)	$ 1,605

Notes:

(A) Deemed cost of property, plant and equipment

In accordance with IFRS transitional provisions, the Company elected to use the deemed cost of property, plant and equipment for its exploration and production assets, which allowed the Company to measure its exploration and evaluation assets at the amounts capitalized under Canadian GAAP at the date of transition to IFRS. Additionally, under the transitional provision, the Company elected to allocate the carrying amount of property, plant and equipment in the development or production phases under Canadian GAAP to IFRS applicable assets pro rata using proved reserve values as at January 1, 2010, subject to impairment tests. The impairment tests compared the carrying amount of the assets to their recoverable amounts. The recoverable amount is the higher of fair value less costs to sell or value in use. The impairment tests conducted by the Company at the date of transition resulted in a $62 million reduction to the carrying amount of property, plant and equipment in the Gabon CGU in Offshore Africa. At January 1, 2010, retained earnings were reduced by $53 million, net of income taxes of $9 million.

For the year ended December 31, 2010, net earnings decreased by $119 million, net of taxes of $27 million, to reflect the impact of higher depletion charges, partially offset by $78 million, net of taxes of $11 million, to reflect the impact of a lower impairment charge on the Gabon CGU in Offshore Africa.

(B) Leases

The Company elected under IFRS 1 not to reassess whether an arrangement contains a lease under IFRIC 4 for contracts that were assessed under Canadian GAAP. Arrangements entered into before the effective date of Canadian GAAP Emerging Issues Committee (“EIC”) 150 that had not subsequently been assessed under EIC 150, were assessed under IFRIC 4, and no additional leases were identified.

(C) Share-based compensation

The Company has granted stock options to all employees, which may be settled in either cash or shares at the holder’s option. The Company accounted for these stock options by reference to their intrinsic value under Canadian GAAP. Under IFRS, the related liability has been adjusted to reflect the fair value of the outstanding share-based compensation. The Company elected to use the IFRS 1 exemption to not retrospectively restate stock option transactions that were settled before the date of transition to IFRS. This adjustment increased the share-based compensation liability by $230 million (December 31, 2010 – $147 million). Included in this amount was $11 million (December 31, 2010 – $19 million) capitalized to Oil Sands Mining and Upgrading. At January 1, 2010, retained earnings were reduced by $170 million, net of income taxes of $49 million.

For the year ended December 31, 2010, net earnings increased by $91 million to reflect differences in share-based compensation expense. In addition, during the year ended December 31, 2010, deferred income tax expense included an additional charge of $49 million related to the change to the taxation of stock options surrendered by employees for cash.

(D) Borrowing costs

Under Canadian GAAP, the Company was not required to capitalize all borrowing costs in respect of constructed assets. At the date of transition, the Company elected to capitalize borrowing costs in respect of all qualifying assets effective January 1, 2010.

(E) Asset retirement obligations

In accordance with IFRS transitional provisions for assets described in (A) above, the Company remeasured the liability associated with asset retirement obligation activities for the North America, North Sea and Offshore Africa Exploration and Production segments at the date of transition, resulting in an increase in asset retirement obligations of $338 million. At January 1, 2010, retained earnings were reduced by $210 million, net of income taxes of $128 million.

In addition, the Company remeasured the liability related to asset retirement obligation activities in the Oil Sands Mining and Upgrading segment at the date of transition. These assets were not subject to the election in (A) above and accordingly, the difference in the liability between Canadian GAAP and IFRS of $266 million was recognized in property, plant and equipment in accordance with IFRS transitional provisions. Additional accumulated depletion of $2 million was recognized in retained earnings.

The difference between Canadian GAAP and IFRS asset retirement obligations related primarily to the method of applying discount rates.

As at December 31, 2010, an additional liability of $234 million was recognized in property, plant and equipment. For the year ended December 31, 2010, net earnings decreased by $15 million, net of taxes of $6 million, to reflect the impact of higher depletion and accretion charges.

(F) Cumulative translation adjustment

In accordance with IFRS transitional provisions, the Company elected to reset the cumulative translation adjustment account, which includes gains and losses arising from the translation of foreign operations, to $nil at the date of transition to IFRS. Accordingly, accumulated other comprehensive income increased by $180 million and retained earnings were reduced by $180 million.

(G) Business combinations

In accordance with IFRS transitional provisions, the Company elected to apply IFRS relating to business combinations prospectively from January 1, 2010. As such, Canadian GAAP balances relating to business combinations entered into before that date have been carried forward without adjustment.

(H) Risk management

Under Canadian GAAP, the Company was required to adjust the carrying amount of the liability for risk management derivative financial instruments by the Company's own credit risk. Under IFRS, this adjustment is not required. The reversal of the credit risk adjustment for IFRS on January 1, 2010 resulted in an increase in the carrying amount of the risk management liability of $16 million (December 31, 2010 – increase of $34 million) and an increase in accumulated comprehensive income of $1 million (December 31, 2010 – decrease of $15 million). At January 1, 2010, retained earnings were reduced by $13 million, net of income taxes of $5 million. Further, differences in applying fair value hedge accounting between Canadian GAAP and IFRS resulted in an increase to the carrying value of hedged long-term debt by $1 million (December 31, 2010 – decrease of $14 million).

For the year ended December 31, 2010, net earnings increased by $10 million, net of income taxes of $4 million and other comprehensive income decreased by $16 million, net of income taxes of $2 million.

(I) Petroleum Revenue Tax

Under Canadian GAAP, the Company calculated its deferred PRT liability using the life-of-field method. Under IFRS, the Company calculates its deferred PRT liability based on temporary differences arising between the tax base of assets and liabilities of PRT paying fields and their carrying amounts in the consolidated balance sheets. As a result of this adjustment, the deferred income tax liability was increased by $116 million ($58 million after-tax) at January 1, 2010 (December 31, 2010 – $80 million, $40 million after-tax). At January 1, 2010, retained earnings were reduced by $58 million.

For the year ended December 31, 2010, net earnings increased by $18 million, net of taxes of $18 million, to reflect the impact of lower PRT charges.

(J) UK deferred income tax liabilities

Under Canadian GAAP, the Company calculated the future income tax liabilities of its UK subsidiaries in UK pounds sterling, and converted the resultant liability to its US dollar functional currency. Under IFRS, the Company calculates its UK-based deferred income tax liabilities directly in the functional US dollar currency. This adjustment resulted in an increase in the deferred income tax liability of $61 million at January 1, 2010 (December 31, 2010 – $80 million). At January 1, 2010, retained earnings were reduced by $61 million.

For the year ended December 31, 2010, net earnings decreased by $19 million.

(K) Reclassification of current portion of deferred income tax

Under Canadian GAAP, deferred income tax relating to current assets or current liabilities were classified as current. Under IFRS, deferred income tax balances are classified as long-term, irrespective of the classification of the assets or liabilities to which the deferred income tax relates or the expected timing of reversal. Accordingly, current deferred income tax assets reported under Canadian GAAP of $146 million at January 1, 2010 (December 31, 2010 – current deferred income tax assets of $59 million) were reclassified as non-current under IFRS.

(L) Horizon major maintenance costs

Under Canadian GAAP, the Company would have deferred and amortized major maintenance turnaround costs on a straight-line basis over the period to the next scheduled major maintenance turnaround. Under IFRS, the Company has identified capitalized components of the original cost of an asset, which have a shorter useful life, and has amortized the costs of these components over the period to the next turnaround. At January 1, 2010, retained earnings decreased by $14 million, net of taxes of $5 million.

For the year ended December 31, 2010, net earnings decreased by $19 million, net of taxes of $6 million, to reflect the impact of higher depletion charges.

(M) Long-term debt

Under Canadian GAAP, debt maturities within one year of the date of the balance sheet were classified as non-current on the basis that the Company had the intent and ability to refinance these obligations with its existing long-term credit facilities. Under IFRS, as the long-term debt maturing within one year was not payable to the same counterparty lenders as the long-term debt facility, $400 million was reclassified to current at January 1, 2010 (December 31, 2010 – $397 million).

Deferred income tax liabilities have been adjusted to give effect to adjustments as follows:

Asset (liability)	Note	December 31 2010	January 1 2010
Deferred income tax assets as reported under Canadian GAAP		$ 59	$ 146
Deferred income tax liabilities as reported under Canadian GAAP		(7,899)	(7,687)
Deferred income tax, net		(7,840)	(7,541)
IFRS adjustments			
Deemed cost of property, plant and equipment	(A)	25	9
Share-based compensation	(C)	–	49
Asset retirement obligations	(E)	134	128
Risk management	(H)	3	5
PRT	(I)	(40)	(58)
UK deferred income tax liabilities	(J)	(80)	(61)
Horizon maintenance costs	(L)	11	5
Foreign exchange and other		(1)	2
Deferred income tax liabilities as reported under IFRS		$ (7,788)	$ (7,462)

The following is a summary of transition adjustments, net of tax, to the Company's accumulated other comprehensive income from Canadian GAAP to IFRS:

	Note	December 31 2010	January 1 2010
Accumulated other comprehensive income as reported under Canadian GAAP		$ (167)	$ (104)
IFRS adjustments			
Cumulative translation adjustment on transition	(F)	180	180
Risk management	(H)	(15)	1
Translation of net investment		11	–
Accumulated other comprehensive income as reported under IFRS		$ 9	$ 77

The following is a summary of transition adjustments, net of tax, to the Company's retained earnings from Canadian GAAP to IFRS:

	Note	December 31 2010	January 1 2010
Retained earnings as reported under Canadian GAAP		$ 18,005	$ 16,696
IFRS adjustments			
Deemed cost of property, plant and equipment	(A)	(94)	(53)
Share-based compensation	(C)	(128)	(170)
Asset retirement obligations	(E)	(227)	(212)
Cumulative translation adjustment	(F)	(180)	(180)
Risk management	(H)	(3)	(13)
PRT	(I)	(40)	(58)
UK deferred income tax liabilities	(J)	(80)	(61)
Horizon maintenance costs	(L)	(33)	(14)
Other		(8)	(8)
Retained earnings as reported under IFRS		$ 17,212	$ 15,927

Adjustments to the statements of cash flows
The transition from Canadian GAAP to IFRS had no significant impact on cash flows generated by the Company.

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, income tax expenses 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 operations and future expansion, ability to recover insurance proceeds, Primrose, Pelican Lake, the Kirby Thermal Oil Sands Project, the Keystone XL Pipeline US Gulf Coast expansion, and the construction and future operations of the North West Redwater bitumen upgrader and 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 as 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 disruptions or delays in the resumption of the mining, extracting or upgrading of 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.

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, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or Management's estimates or opinions change.

SPECIAL NOTE REGARDING NON-GAAP FINANCIAL MEASURES

This MD&A 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 International Financial Reporting Standards ("IFRS") 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 IFRS, 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 IFRS, 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

MD&A 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, 2011.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. Common share data and per common share amounts have been restated to reflect the two-for-one common share split in May 2010.The Company's consolidated financial statements and this MD&A have been prepared in accordance with IFRS, as issued by the International Accounting Standards Board ("IASB"). Unless otherwise stated, 2010 comparative figures have been restated in accordance with IFRS issued as at December 31, 2011. Comparative figures for 2009 have not been restated from Canadian GAAP as previously reported and may not be prepared on a basis consistent with IFRS as adopted.

A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if 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 a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this MD&A, crude oil is defined to include the following commodities: light & medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and synthetic crude oil.

Production volumes and per unit 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 2011 financial results compared to 2010 and 2009, unless otherwise indicated. In addition, this MD&A details the Company's capital program and outlook for 2012. Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2011, its Annual Information Form for the year ended December 31, 2011, and its audited consolidated financial statements for the year ended December 31, 2011 is available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. This MD&A is dated March 6, 2012.

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
C$	Canadian dollars
CAGR	Compound annual growth rate
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 prior to adoption of IFRS on January 1, 2011
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
IASB	International Accounting Standards Board
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

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, safe, effective and efficient operations as well as cost control are fundamental to the Company. By consistently managing costs throughout all cycles of the industry, the Company believes it will achieve continued growth. Effective and efficient operations and cost control are 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 areas.

Highlights for the year ended December 31, 2011 include the following:

§ Achieved net earnings of $2.6 billion, adjusted net earnings from operations of $2.5 billion, and cash flow from operations of $6.5 billion;

§ Achieved record yearly crude oil and NGLs production of 295,618 bbl/d in the North America – Exploration and Production segment;

§ Achieved annual crude oil and natural gas production guidance in the Exploration and Production segment;

§ Drilled a record 783 net primary heavy crude oil wells;

- Successfully and safely recommenced operations at Horizon following the suspension of SCO production due to a fire in the primary upgrading coking plant;
- Acquired approximately $1 billion of crude oil and natural gas properties in the Company's core areas in Western Canada;
- Purchased 3,071,100 common shares for a total cost of $104 million under the Normal Course Issuer Bid; and
- Increased annual per share dividend payment to $0.36 from $0.30, our 11th consecutive year of dividend increases.

NET EARNINGS AND CASH FLOW FROM OPERATIONS

Financial Highlights

($ millions, except per common share amounts)		2011	2010	2009(1)(4)
Product sales		$ 15,507	$ 14,322	$ 11,078
Net earnings		$ 2,643	$ 1,673	$ 1,580
Per common share	– basic	$ 2.41	$ 1.54	$ 1.46
	– diluted	$ 2.40	$ 1.53	$ 1.46
Adjusted net earnings from operations (2)		$ 2,540	$ 2,444	$ 2,689
Per common share	– basic	$ 2.32	$ 2.25	$ 2.48
	– diluted	$ 2.30	$ 2.23	$ 2.48
Cash flow from operations (3)		$ 6,547	$ 6,333	$ 6,090
Per common share	– basic	$ 5.98	$ 5.82	$ 5.62
	– diluted	$ 5.94	$ 5.78	$ 5.62
Dividends declared per common share		$ 0.36	$ 0.30	$ 0.21
Total assets		$ 47,278	$ 42,954	$ 41,024
Total long-term liabilities		$ 20,346	$ 18,880	$ 19,193
Capital expenditures, net of dispositions		$ 6,414	$ 5,514	$ 2,997

(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 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.

(4) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

Adjusted Net Earnings from Operations

($ millions)	2011	2010	2009(6)
Net earnings as reported	$ 2,643	$ 1,673	$ 1,580
Share-based compensation (recovery) expense, net of tax (1)(5)	(102)	203	261
Unrealized risk management (gain) loss, net of tax (2)	(95)	(16)	1,437
Unrealized foreign exchange loss (gain), net of tax (3)	215	(142)	(570)
Gabon, Offshore Africa asset impairment	–	594	–
	(225)	–	–

Realized foreign exchange gain on repayment of US dollar debt securities, net of tax(4)			
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (5)	104	132	(19)
Adjusted net earnings from operations	$ 2,540	$ 2,444	$ 2,689

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

(2) Derivative financial instruments are recorded at fair value on the balance sheets, 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.

(3) 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 swaps, and are recognized in net earnings.

(4) During 2011, the Company repaid US$400 million of US dollar debt securities bearing interest at 6.70%.

(5) 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 balance sheets in determining deferred 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. During 2011, the UK government enacted an increase to the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%. The Company's deferred income tax liability was increased by $104 million with respect to this tax rate change. During 2010, changes in Canada to the taxation of stock options surrendered by employees for cash payments resulted in a $132 million charge to deferred income tax expense. During 2009, reductions in the British Columbia corporate income tax rate resulted in one time deferred tax recoveries of $19 million.

(6) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

Cash Flow from Operations

($ millions)	2011	2010	2009(1)
Net earnings	$2,643	$1,673	$1,580
Non-cash items:			
Depletion, depreciation and amortization	3,604	4,120	2,819
Share-based compensation (recovery) expense	(102)	203	355
Asset retirement obligation accretion	130	123	90
Unrealized risk management (gain) loss	(128)	(24)	1,991
Unrealized foreign exchange loss (gain)	215	(161)	(661)
Realized foreign exchange gain on repayment of US dollar debt securities	(225)	–	–
Deferred income tax expense (recovery)	407	399	(84)
Horizon asset impairment provision	396	–	–
Insurance recovery – property damage	(393)	–	–
Cash flow from operations	$6,547	$6,333	$6,090

(1) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

For 2011, the Company reported net earnings of $2,643 million compared to net earnings of $1,673 million for 2010 (2009 – $1,580 million). Net earnings for 2011 included net unrealized after-tax income of $103 million related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the impact of realized foreign exchange gain on repayment of long-term debt and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities (2010 – $771 million after-tax expenses; 2009 – $1,109 million after-tax expenses). Excluding these items, adjusted net earnings from operations for 2011 increased to $2,540 million from $2,444 million for 2010 (2009 – $2,689 million).

The increase in adjusted net earnings for 2011 from 2010 was primarily due to:

§ higher North America crude oil and NGL sales volumes;
§ higher crude oil and NGL netbacks; and
§ lower net interest and other financing costs;

partially offset by:

§ the impact of suspension of production at Horizon, net of business interruption insurance;
§ lower natural gas netbacks;
§ realized risk management losses; and
§ the impact of a stronger Canadian dollar.

The impacts of share-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 2011 increased to $6,547 million ($5.98 per common share) from $6,333 million ($5.82 per common share) for 2010 (2009 – $6,090 million; $5.62 per common share). The increase in cash flow from operations for 2011 from 2010 was primarily due to:

§ higher North America crude oil and NGL sales volumes;
§ higher crude oil and NGL netbacks; and
§ lower net interest and other financing costs;

partially offset by:

- the impact of suspension of production at Horizon, net of business interruption insurance;
- lower natural gas netbacks;
- realized risk management losses;
- the impact of a stronger Canadian dollar; and
- higher cash taxes.

In the Company's Exploration and Production activities, the 2011 average sales price per bbl of crude oil and NGLs increased 18% to average $77.46 per bbl from $65.81 per bbl in 2010 (2009 – $57.68 per bbl), and the average natural gas price decreased 9% to average $3.73 per Mcf from $4.08 per Mcf in 2010 (2009 – $4.53 per Mcf). The Company's average sales price of SCO increased 28% to average $99.74 per bbl from $77.89 per bbl in 2010 (2009 – $70.83).

Total production of crude oil and NGLs before royalties decreased 8% to 389,053 bbl/d from 424,985 bbl/d in 2010 (2009 – 355,463 bbl/d). The decrease in crude oil and NGLs production from 2010 was primarily due to the suspension of production at Horizon, partially offset by the impact of a record heavy oil drilling program and the cyclic nature of the Company's thermal operations.

Total natural gas production before royalties increased 1% to average 1,257 MMcf/d from 1,243 MMcf/d in 2010 (2009 – 1,315 MMcf/d). The increase in natural gas production primarily reflected new production volumes from natural gas producing properties acquired during 2010 and 2011.

Total crude oil and NGLs and natural gas production volumes before royalties decreased 5% to average 598,526 BOE/d from 632,191 BOE/d in 2010 (2009 – 574,730 BOE/d). Total production for 2011 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)

2011	Total	Dec 31	Sep 30	Jun 30	Mar 31
Product sales	$15,507	$4,788	$3,690	$3,727	$3,302
Net earnings	$2,643	$832	$836	$929	$46
Net earnings per common share					
– basic	$2.41	$0.76	$0.76	$0.85	$0.04
– diluted	$2.40	$0.76	$0.76	$0.84	$0.04

2010	Total	Dec 31	Sep 30	Jun 30	Mar 31(1)
Product sales	$14,322	$3,787	$3,341	$3,614	$3,580
Net earnings (loss)	$1,673	$(309)	$596	$651	$735
Net earnings (loss) per common share					
– basic	$1.54	$(0.28)	$0.54	$0.60	$0.68
– diluted	$1.53	$(0.28)	$0.54	$0.60	$0.67

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

Volatility in the 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, the impact of the WCS Heavy Differential ("WCS Differential") in North America and the impact of the differential between WTI and Dated Brent benchmark pricing in the North Sea and Offshore Africa.

§ Natural gas pricing – The impact of 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 impact of the suspension and recommencement of production at Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore Africa, and payout of the Baobab field in May 2011.

- § 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 and timing 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 suspension and recommencement of production at both 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 suspension and recommencement of operations at Horizon and the impact of impairments at the Olowi field in Offshore Gabon in 2010.

§ Share-based compensation – Fluctuations due to the mark-to-market movements of the Company's share-based compensation liability.

§ 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.

§ Foreign exchange rates – Changes in the Canadian dollar relative to the US dollar that 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 realized and unrealized foreign exchange gains and losses are recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.

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

BUSINESS ENVIRONMENT

(Yearly average)	2011	2010	2009
WTI benchmark price (US$/bbl)	$95.14	$79.55	$61.93
Dated Brent benchmark price (US$/bbl)	$111.29	$79.50	$61.61
WCS blend differential from WTI (US$/bbl)	$17.10	$14.26	$9.64
WCS blend differential from WTI (%)	18%	18%	16%
SCO price (US$/bbl)	$103.63	$78.56	$61.51
Condensate benchmark price (US$/bbl)	$105.38	$81.81	$60.60
NYMEX benchmark price (US$/MMBtu)	$4.07	$4.42	$4.03
AECO benchmark price (C$/GJ)	$3.48	$3.91	$3.91
US / Canadian dollar average exchange rate (US$)	$1.0111	$0.9709	$0.8760
US / Canadian dollar year end exchange rate (US$)	$0.9833	$1.0054	$0.9555

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 prices are 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 2011, with a high of approximately US$1.06 in July 2011 and a low of approximately US$0.95 in October 2011.

WTI pricing in 2011 was reflective of the political instability in the Middle East and North Africa and continued strong Asian demand. The relative weakness of the US dollar also contributed to higher WTI pricing. For 2011, WTI averaged US$95.14 per bbl, an increase of 20% compared to US$79.55 per bbl for 2010 (2009 – US$61.93 per bbl).

Brent averaged US$111.29 per bbl for 2011, an increase of 40% compared to US$79.50 per bbl for 2010 (2009 – US$61.61 per bbl). Crude oil sales contracts for the North Sea and Offshore Africa are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. The higher Dated Brent ("Brent") pricing relative to WTI in 2011 compared to 2010 was due to the limited pipeline capacity between Petroleum Administration for Defence Districts II ("PADD II") and the United States Gulf Coast. This logistical constraint is preventing lower WTI priced barrels delivered into PADD II from obtaining United States Gulf Coast Brent-based pricing.

The WCS Heavy Differential averaged 18% of WTI for 2011 and 2010 (2009 – 16%).

The Company uses condensate as a blending diluent for heavy crude oil pipeline shipments. During 2011 and 2010, condensate prices traded at a premium to WTI, reflecting the tight supply situation.

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

NYMEX natural gas prices averaged US$4.07 per MMBtu for 2011, a decrease of 8% from US$4.42 per MMBtu for 2010 (2009 – US$4.03 per MMBtu). AECO natural gas pricing averaged $3.48 per GJ for 2011, a decrease of 11% from US$3.91 per GJ for 2010 (2009 – $3.91 per GJ). Natural gas prices continue to be weak in response to the strong North America supply position, primarily from the highly productive shale areas.

Operating, Royalty and Capital Costs

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

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.

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

		Changes due to				Changes due to			
($ millions)	2009	Volumes	Prices	Other	2010	Volumes	Prices	Other	2011
North America									
Crude oil and NGLs	$5,738	$938	$1,127	$2	$7,805	$708	$1,448	$90	$10,051
Natural gas	2,235	(121)	(206)	–	1,908	21	(174)	–	1,755
	7,973	817	921	2	9,713	729	1,274	90	11,806
North Sea									
Crude oil and NGLs	944	(71)	171	(1)	1,043	(139)	292	19	1,215
Natural gas	17	–	(2)	–	15	(5)	(1)	–	9
	961	(71)	169	(1)	1,058	(144)	291	19	1,224
Offshore Africa									
Crude oil and NGLs	872	(130)	104	–	846	(191)	220	3	878
Natural gas	41	(6)	3	–	38	9	21	–	68
	913	(136)	107	–	884	(182)	241	3	946
Subtotal									
Crude oil and NGLs	7,554	737	1,402	1	9,694	378	1,960	112	12,144
Natural gas	2,293	(127)	(205)	–	1,961	25	(154)	–	1,832
	9,847	610	1,197	1	11,655	403	1,806	112	13,976
Oil Sands Mining and Upgrading	1,253	1,175	221	–	2,649	(1,458)	322	8	1,521
Midstream	72	–	–	7	79	–	–	9	88
Intersegment eliminations and other (1)	(94)	–	–	33	(61)	–	–	(17)	(78)
Total	$11,078	$1,785	$1,418	$41	$14,322	$(1,055)	$2,128	$112	$15,507

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

Revenue increased 8% to $15,507 million for 2011 from $14,322 million for 2010 (2009 – $11,078 million). The increase was primarily due to an increase in realized crude oil and NGL and SCO prices, partially offset by a decrease in realized natural gas prices and Oil Sands Upgrading and Mining sales volumes.

For 2011, 14% of the Company’s crude oil and natural gas revenue was generated outside of North America (2010 – 13%; 2009 – 17%). North Sea accounted for 8% of crude oil and natural gas revenue for 2011 (2010 – 7%; 2009 – 9%), and Offshore Africa accounted for 6% of crude oil and natural gas revenue for 2011 (2010 – 6%; 2009 – 8%).

ANALYSIS OF DAILY PRODUCTION, BEFORE ROYALTIES

	2011	2010	2009
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	295,618	270,562	234,523
North America – Oil Sands Mining and Upgrading	40,434	90,867	50,250
North Sea	29,992	33,292	37,761
Offshore Africa	23,009	30,264	32,929
	389,053	424,985	355,463
Natural gas (MMcf/d)			
North America	1,231	1,217	1,287
North Sea	7	10	10
Offshore Africa	19	16	18
	1,257	1,243	1,315
Total barrels of oil equivalent (BOE/d)	598,526	632,191	574,730
Product mix			
Light and medium crude oil and NGLs	18%	18%	21%
Pelican Lake heavy crude oil	6%	6%	6%
Primary heavy crude oil	18%	15%	15%
Bitumen (thermal oil)	16%	14%	11%
Synthetic crude oil	7%	14%	9%
Natural gas	35%	33%	38%
Percentage of gross revenue (1)			
(excluding midstream revenue)			
Crude oil and NGLs	86%	85%	78%
Natural gas	14%	15%	22%

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

ANALYSIS OF DAILY PRODUCTION, NET OF ROYALTIES

	2011	2010	2009
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	240,006	219,736	201,873
North America – Oil Sands Mining and Upgrading	38,721	87,763	48,833
North Sea	29,919	33,227	37,683
Offshore Africa	20,532	28,288	29,922
	329,178	369,014	318,311
Natural gas (MMcf/d)			
North America	1,186	1,168	1,214
North Sea	7	10	10
Offshore Africa	16	15	17
	1,209	1,193	1,241
Total barrels of oil equivalent (BOE/d)	530,576	567,743	525,103

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 598,526 BOE/d for 2011, a 5% decrease from 632,191 BOE/d in 2010 (2009 – 574,730 BOE/d).

Total production of crude oil and NGLs before royalties decreased 8% to 389,053 bbl/d for 2011 from 424,985 bbl/d in 2010 (2009 – 355,463 bbl/d). The decrease in crude oil and NGLs production from 2010 was primarily due to the suspension of production at Horizon, partially offset by the impact of a record heavy crude oil drilling program and the cyclic nature of the Company's thermal operations. Crude oil and NGLs production for 2011 was within the Company's previously issued guidance of 385,000 to 393,000 bbl/d.

Natural gas production continued to represent the Company's largest product offering, accounting for 35% of the Company's total production in 2011 on a BOE basis. Total natural gas production before royalties increased 1% to 1,257 MMcf/d for 2011 from 1,243 MMcf/d for 2010 (2009 – 1,315 MMcf/d). The increase in natural gas production from 2010 primarily reflected the new production volumes from Septimus and natural gas producing properties acquired during 2010 and 2011. These increases were partially offset by expected production declines due to the allocation of capital to higher return crude oil projects, which resulted in a strategic reduction of natural gas drilling activity. Natural gas production for 2011 was at the low end of the Company's issued guidance of 1,256 to 1,263 MMcf/d.

North America – Exploration and Production
North America crude oil and NGLs production for 2011 increased 9% to average 295,618 bbl/d from 270,562 bbl/d for 2010 (2009 – 234,523 bbl/d). The increase in production from 2010 was primarily due to the impact of a record heavy oil drilling program and the cyclic nature of the Company's thermal operations. The Company's heavy oil drilling continues on track and exited 2011 at over 115,000 bbl/d, an increase of approximately 19% compared to the first quarter of 2011.

North America natural gas production for 2011 increased 1% to average 1,231 MMcf/d from 1,217 MMcf/d in 2010 (2009 –1,287 MMcf/d). The increase in natural gas production from 2010 reflected new production volumes from Septimus and natural gas producing properties acquired during 2010 and 2011, offset by the impact of expected production declines due to the allocation of capital to higher return crude oil projects, which resulted in a strategic reduction of natural gas drilling activity. During 2011, the Company completed a pipeline to a deep cut gas facility, which increased Septimus liquids recoveries.

North America – Oil Sands Mining and Upgrading

As a result of a fire at Horizon's primary upgrading coking plant on January 6, 2011, all SCO production was suspended. On August 16, 2011, the Company successfully and safely recommenced operations. First pipeline deliveries commenced on August 18, 2011. As a result, production averaged 40,434 bbl/d for 2011, compared to 90,867 bbl/d for 2010. Subsequent to December 31, 2011, the Company temporarily suspended synthetic crude oil production at Horizon on February 5, 2012 to complete unplanned maintenance on the fractionating unit in the primary upgrading facility. The Company has targeted mid to late March to return to full production levels.

North Sea

North Sea crude oil production for 2011 was 29,992 bbl/d, a decrease of 10% from 33,292 bbl/d for 2010 (2009 – 37,761 bbl/d). The decrease in production volumes from 2010 was due to natural field declines and timing of scheduled maintenance shut downs in 2011.

In December 2011, the Banff FPSO and subsea infrastructure suffered storm damage. Operations at Banff/Kyle, with combined net production of approximately 3,500 bbl/d, were suspended and appropriate shut down procedures were activated. The FPSO and associated floating storage unit have subsequently been removed from the field, and the extent of the damage, including associated costs and timing of returning to the field, is currently being assessed.

Offshore Africa

Offshore Africa crude oil production for 2011 decreased 24% to 23,009 bbl/d from 30,264 bbl/d for 2010 (2009 – 32,929 bbl/d), due to natural field declines and the payout of the Baobab field in May 2011.

Guidance

The Company targets production levels in 2012 to average between 440,000 bbl/d and 480,000 bbl/d of crude oil and NGLs and between 1,247 MMcf/d and 1,297 MMcf/d of natural gas.

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 FPSOs as follows:

(bbl)	2011	2010	2009
North America – Exploration and Production	557,475	761,351	1,131,372
North America – Oil Sands Mining and Upgrading (SCO)	1,021,236	1,172,200	1,224,481
North Sea	286,633	264,995	713,112
Offshore Africa	527,312	404,197	51,103
	2,392,656	2,602,743	3,120,068

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	2011	2010	2009(3)
Crude oil and NGLs ($/bbl) (1)			
Sales price (2)	$77.46	$65.81	$57.68
Royalties	12.30	10.09	6.73
Production expense	15.75	14.16	15.92
Netback	$49.41	$41.56	$35.03
Natural gas ($/Mcf) (1)			
Sales price (2)	$3.73	$4.08	$4.53
Royalties	0.18	0.20	0.32
Production expense	1.15	1.09	1.08
Netback	$2.40	$2.79	$3.13
Barrels of oil equivalent ($/BOE) (1)			
Sales price (2)	$57.16	$49.90	$44.87
Royalties	8.12	6.72	4.72
Production expense	12.42	11.25	11.98
Netback	$36.62	$31.93	$28.17

(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) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

ANALYSIS OF PRODUCT PRICES – EXPLORATION AND PRODUCTION

	2011	2010	2009(3)
Crude oil and NGLs ($/bbl) (1) (2)			
North America	$72.17	$62.28	$54.70
North Sea	$108.56	$82.49	$68.84
Offshore Africa	$105.53	$78.93	$65.27
Company average	$77.46	$65.81	$57.68
Natural gas ($/Mcf) (1) (2)			
North America	$3.64	$4.05	$4.51
North Sea	$4.07	$3.83	$4.66
Offshore Africa	$9.56	$6.63	$6.11
Company average	$3.73	$4.08	$4.53
Company average ($/BOE) (1) (2)	$57.16	$49.90	$44.87

(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) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

Realized crude oil and NGLs prices increased 18% to average $77.46 per bbl for 2011 from $65.81 per bbl for 2010 (2009 – $57.68 per bbl). The increase in 2011 was primarily a result of higher WTI and Brent benchmark crude oil prices during the year, partially offset by the impact of a stronger Canadian dollar.

The Company's realized natural gas price decreased 9% to average $3.73 per Mcf for 2011 from $4.08 per Mcf for 2010 (2009 – $4.53 per Mcf). The decrease in 2011 was primarily related to lower NYMEX and AECO benchmark pricing related to the impact of strong supply from US shale projects.

North America

North America realized crude oil prices increased 16% to average $72.17 per bbl for 2011 from $62.28 per bbl for 2010 (2009 – $54.70 per bbl). The increase in 2011 was primarily a result of higher WTI benchmark pricing, partially offset by the impact of a stronger Canadian dollar.

The Company continues to focus on its crude oil marketing strategy, including 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 2011, the Company contributed approximately 162,000 bbl/d of heavy crude oil blends to the WCS stream. The Company has entered into a 20 year transportation agreement to ship 120,000 bbl/d of heavy crude oil on the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf Coast. The Company also entered into a 20 year crude oil purchase and sales agreement to sell 100,000 bbl/d of heavy crude oil to a major US refiner. In January 2012, the Presidential permit for the Keystone XL pipeline was denied until such time as a new route through Nebraska is determined. Final recommendation from the US State department is anticipated in the first quarter of 2013, with an expected pipeline in-service date in 2015.

During 2011, 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 upgrader and refinery near Redwater, Alberta. In addition, the partnership entered into a 30 year fee-for-service agreement to process bitumen supplied by the Company and the Government of Alberta under the Bitumen Royalty In Kind initiative. Project development is dependent upon completion of detailed engineering and final project sanction by the partnership and its partners and approval of the final tolls. Board sanction is currently targeted for 2012.

North America realized natural gas prices decreased 10% to average $3.64 per Mcf for 2011 from $4.05 per Mcf for 2010 (2009 – $4.51 per Mcf), primarily related to the impact of strong supply from US shale projects.

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

(Yearly average)	2011	2010	2009
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs (C$/bbl)	$82.01	$68.02	$57.02
Pelican Lake heavy crude oil (C$/bbl)	$71.45	$61.69	$55.52
Primary heavy crude oil (C$/bbl)	$70.51	$62.04	$55.66
Bitumen (thermal oil) (C$/bbl)	$68.55	$59.55	$51.18
Natural gas (C$/Mcf)	$3.64	$4.05	$4.51

(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 32% to average $108.56 per bbl for 2011 from $82.49 per bbl for 2010 (2009 – $68.84 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 2010 reflected fluctuations in Brent benchmark pricing and the US dollar.

Offshore Africa

Offshore Africa realized crude oil prices increased 34% to average $105.53 per bbl for 2011 from $78.93 per bbl for 2010 (2009 – $65.27 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 Africa from 2010 reflected fluctuations in Brent benchmark pricing and the US dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	2011	2010	2009(2)
Crude oil and NGLs ($/bbl) (1)			
North America	$13.51	$11.85	$7.93
North Sea	$0.26	$0.16	$0.14
Offshore Africa	$12.47	$5.54	$5.79
Company average	$12.30	$10.09	$6.73
Natural gas ($/Mcf) (1)			
North America	$0.16	$0.20	$0.32
Offshore Africa	$1.59	$0.53	$0.53
Company average	$0.18	$0.20	$0.32
Company average ($/BOE) (1)	$8.12	$6.72	$4.72

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

(2) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

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”). Effective January 1, 2009, changes to the Alberta royalty regime resulted in 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 averaged approximately 19% of product sales in 2011 and were comparable to 2010 (2009 – 14%). North America crude oil and NGLs royalties per bbl are anticipated to average 18% to 21% of gross revenue for 2012.

Natural gas royalties averaged approximately 4% of gross revenues for 2011 compared to 5% in 2010 (2009 – 7%), primarily due to lower benchmark natural gas prices. North America natural gas royalties per Mcf are anticipated to average 1% to 3% of gross revenue for 2012.

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 Africa

Under the terms of the various Production Sharing Contracts (“PSCs”), royalty rates fluctuate based on realized commodity pricing, capital costs, the status of payouts, and the timing of liftings from each field.

Royalty rates as a percentage of revenue averaged approximately 17% for 2011 compared to 7% for 2010 (2009 – 9%) primarily due to higher crude oil pricing and payout of the Baobab field. Offshore Africa royalty rates are anticipated to average 13% to 15% for 2012.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	2011	2010	2009(2)
Crude oil and NGLs ($/bbl) (1)			
North America	$13.21	$12.14	$14.63
North Sea	$37.06	$29.73	$26.98
Offshore Africa	$20.72	$14.64	$12.83
Company average	$15.75	$14.16	$15.92
Natural gas ($/Mcf) (1)			
North America	$1.12	$1.06	$1.07
North Sea	$2.83	$2.91	$2.16
Offshore Africa	$2.03	$1.76	$1.23
Company average	$1.15	$1.09	$1.08
Company average ($/BOE) (1)	$12.42	$11.25	$11.98

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

(2) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

North America

North America crude oil and NGLs production expense for 2011 increased 9% to $13.21 per bbl from $12.14 per bbl for 2010 (2009 – $14.63 per bbl). The increase in production expense per bbl from 2010 was primarily a result of higher overall service costs relating to heavy crude oil production and the timing of thermal steam cycles. North America crude oil and NGLs production expense is anticipated to average $11.00 to $13.00 per bbl for 2012.

North America natural gas production expense for 2011 increased 6% to $1.12 per Mcf, from $1.06 per Mcf for 2010 (2009 – $1.07 per Mcf). Natural gas production expense increased from 2010 due to acquisitions of natural gas producing properties that have higher production costs per Mcf than the Company's existing properties. North America natural gas production expense is anticipated to average $1.10 to $1.20 per Mcf for 2012.

North Sea

North Sea crude oil production expense for 2011 increased 25% to $37.06 per bbl from $29.73 per bbl for 2010 (2009 - $26.98 per bbl). Production expense increased on a per barrel basis due to lower production volumes on relatively fixed costs and increased fuel prices. North Sea crude oil production expense is anticipated to average $43.00 to $48.00 per bbl for 2012.

Offshore Africa

Offshore Africa crude oil production expense for 2011 increased 42% to $20.72 per bbl from $14.64 per bbl for 2010 (2009 - $12.83 per bbl). Production expense increased on a per barrel basis due to lower production volumes on relatively fixed costs, and the timing of liftings from each field. Offshore Africa crude oil production expense is anticipated to average $27.00 to $29.00 per bbl for 2012.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts) (1)	2011	2010	2009(2)
North America	$2,840	$2,484	$2,060
North Sea	249	297	261
Offshore Africa	242	935	335
Expense	$3,331	$3,716	$2,656
$/BOE	$16.35	$18.76	$13.82

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

Depletion, Depreciation and Amortization expense for 2011 decreased to $3,331 million from $3,716 million for 2010 (2009 – $2,656 million), due to lower sales volumes in the North Sea and Offshore Africa, and the impact of an impairment related to Gabon, Offshore Africa at December 31, 2010, partially offset by higher sales volumes in North America.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts) (1)	2011	2010	2009(2)
North America	$70	$52	$41
North Sea	33	36	24
Offshore Africa	7	7	4
Expense	$110	$95	$69
$/BOE	$0.54	$0.47	$0.36

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

On January 6, 2011, the Company suspended SCO production at its Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. The Company successfully and safely recommenced operations on August 16, 2011. First pipeline deliveries commenced on August 18, 2011. As a result, production averaged 40,434 bbl/d for 2011, compared to 90,867 bbl/d for 2010 (2009 – 50,250 bbl/d).

Subsequent to December 31, 2011, the Company temporarily suspended synthetic crude oil production at Horizon on February 5, 2012 to complete unplanned maintenance on the fractionating unit in the primary upgrading facility. The Company has targeted mid to late March to return to full production levels.

PRODUCT PRICES AND ROYALTIES – OIL SANDS MINING AND UPGRADING

($/bbl) (1)	2011	2010	2009(5)
SCO sales price (2)	$99.74	$77.89	$70.83
Bitumen value for royalty purposes (3)	$61.86	$56.14	$56.57
Bitumen royalties (4)	$3.99	$2.72	$2.15

(1) Amounts expressed on a per unit basis in 2011 are based on sales volumes excluding the period during suspension of production.
(2) Net of transportation and excluding risk management activities.
(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.
(5) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

Realized SCO sales prices increased 28% to average $99.74 per bbl for 2011 from $77.89 per bbl for 2010 (2009 – $70.83 per bbl). The increase in SCO prices from 2010 was primarily due to the increase in the WTI benchmark price, partially offset by the impact of a stronger Canadian dollar.

PRODUCTION COST – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 20 to the Company's consolidated financial statements.

($ millions)	2011	2010	2009(1)
Cash costs	$1,127	$1,208	$683
Less: costs incurred during the period of suspension of production	(581)	–	–
Adjusted cash costs	$546	$1,208	$683
Adjusted cash costs, excluding natural gas costs	$502	$1,082	$599
Adjusted natural gas costs	44	126	84
Adjusted cash production costs	$546	$1,208	$683

(1) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

($/bbl) (1)	2011	2010	2009(2)
Adjusted cash costs, excluding natural gas costs	$33.68	$32.58	$34.97
Adjusted natural gas costs	2.96	3.78	4.92
Adjusted cash production costs	$36.64	$36.36	$39.89
Sales (bbl/d)	40,847	91,010	46,896

(1) Amounts expressed on a per unit basis in 2011 are based on sales volumes excluding the period during suspension of production.
(2) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

Adjusted cash production costs averaged $36.64 per bbl for 2011, an increase of 1% compared to $36.36 per bbl for 2010 (2009 – $39.89 per bbl).

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions)	2011	2010	2009(2)
Depletion, depreciation and amortization	$266	$396	$187
Less: depreciation incurred during the period of suspension of production	(64)	–	–
Adjusted depletion, depreciation and amortization	$202	$396	$187
$/bbl (1)	$13.54	$11.91	$10.95

(1) Amounts expressed on a per unit basis in 2011 are based on sales volumes excluding the period during suspension of production.

(2) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

Depletion, depreciation and amortization expense for 2011 decreased from 2010 primarily due to the impact of the Horizon suspension.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	2011	2010	2009(2)
Expense ($ millions)	$20	$28	$21
$/bbl (1)	$1.33	$0.88	$1.22

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

MIDSTREAM

($ millions)	2011	2010	2009(1)
Revenue	$88	$79	$72
Production expense	26	22	19
Midstream cash flow	62	57	53
Depreciation	7	8	9
Segment earnings before taxes	$55	$49	$44

(1) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

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)	2011	2010	2009(2)
Expense	$235	$211	$181
$/BOE	$1.07	$0.92	$0.87

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

Administration expense for 2011 increased from 2010 primarily due to higher staffing and general corporate costs.

SHARE-BASED COMPENSATION

($ millions)	2011	2010	2009(1)
(Recovery) expense	$(102)	$203	$355

(1) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

The Company's Stock Option Plan (the "Option Plan") provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered.

The Company recorded a $102 million share-based compensation recovery during 2011 primarily as a result of remeasurement of the fair value of outstanding stock options at the end of the period, related to a decrease in the Company's share price, offset by normal course graded vesting of stock options granted in prior periods and the impact of vested stock options exercised or surrendered during the period. For the year ended December 31, 2011, no net amounts were capitalized in respect of share-based compensation to Oil Sands Mining and Upgrading (2010 – capitalized $32 million; 2009 – capitalized $2 million).

The share-based compensation liability at December 31, 2011 reflected the Company's liability for awards granted to employees at fair value estimated using the Black-Scholes valuation model. In periods when substantial stock price changes occur, the Company's net earnings are subject to significant volatility. The Company utilizes its share-based compensation plan to attract and retain employees in a competitive environment. All employees participate in this plan.

During 2011, the Company paid $14 million for stock options surrendered for cash payments (2010 – $45 million; 2009 – $94 million).

INTEREST AND OTHER FINANCING COSTS

($ millions, except per BOE amounts and interest rates) (1)	2011	2010	2009(2)
Expense, gross	$432	$476	$516
Less: capitalized interest	59	28	106
Expense, net	$373	$448	$410
$/BOE	$1.71	$1.94	$1.96
Average effective interest rate	4.7%	4.9%	4.3%

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

Gross interest and other financing costs for 2011 decreased from 2010 due to the impact of a stronger Canadian dollar on US dollar denominated debt, partially offset by higher average debt levels and variable interest rates. Capitalized interest for 2011 increased from 2010 due to additional amounts relating to Horizon and the Kirby Project.

The Company's average effective interest rate for 2011 decreased from 2010 primarily due to settlement of the US$400 million of 6.70% US dollar denominated debt securities and subsequent issuance of US$500 million of 1.45% unsecured notes due November 2014 and US$500 million of 3.45% unsecured notes due November 2021.

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)	2011	2010	2009(1)
Crude oil and NGLs financial instruments	$117	$84	$(1,330)
Natural gas financial instruments	–	(234)	(33)
Foreign currency contracts and interest rate swaps	(16)	40	110
Realized loss (gain)	$101	$(110)	$(1,253)
Crude oil and NGLs financial instruments	$(134)	$(108)	$2,039
Natural gas financial instruments	–	72	(58)
Foreign currency contracts and interest rate swaps	6	12	10
Unrealized (gain) loss	$(128)	$(24)	$1,991
Net (gain) loss	$(27)	$(134)	$738

(1) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

Complete details related to outstanding derivative financial instruments at December 31, 2011 are disclosed in note 17 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 fair value at December 31, 2011.

Due to changes in crude oil forward pricing and the reversal of prior period unrealized gains and losses related to crude oil and foreign currency contracts, the Company recorded a net unrealized gain of $128 million ($95 million after-tax) on its risk management activities for 2011 (2010 – $24 million unrealized gain, $16 million after-tax; 2009 – $1,991 million unrealized loss, $1,437 million after-tax).

FOREIGN EXCHANGE

($ millions)	2011	2010	2009(2)
Net realized (gain) loss	$(214)	$(2)	$30
Net unrealized loss (gain) (1)	215	(161)	(661)
Net loss (gain)	$1	$(163)	$(631)

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

(2) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

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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 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 loss in 2011 was primarily due to the reversal of the unrealized foreign exchange gain on the settlement of the US$400 million 6.70% US dollar denominated debt securities, together with the weakening of the Canadian dollar at December 31, 2011 with respect to US dollar denominated debt. Included in the net unrealized loss for 2011 was an unrealized gain of $42 million (2010 – $101 million unrealized loss, 2009 – $338 million unrealized loss) related to the impact of cross currency swaps. The net realized foreign exchange gain for 2011 was primarily due to the settlement of the US$400 million 6.70% US dollar denominated debt securities, partially offset by 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$0.9833 compared to US$1.0054 at December 31, 2010 (December 31, 2009 – US$0.9555).

TAXES

($ millions, except income tax rates)	2011	2010	2009(4)
North America (1)	$315	$431	$28
North Sea	245	203	278
Offshore Africa	140	64	82
PRT expense – North Sea	135	68	70
Other taxes	25	23	21
Current income tax	860	789	479
Deferred income tax expense (recovery)	412	408	(99)
Deferred PRT expense – North Sea	(5)	(9)	15
Deferred income tax	407	399	(84)
	1,267	1,188	395
Income tax rate and other legislative changes (2)	(104)	(132)	19
	$1,163	$1,056	$414
Effective income tax rate on adjusted net earnings from operations(3)	27.7%	28.9%	24.3%

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

(2) Deferred income tax expense in 2011 included a charge of $104 million related to enacted changes in the UK to increase the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%. Deferred income tax expense in 2010 included a charge of $132 million related to changes in Canada to the taxation of stock options surrendered by employees for cash payments. Deferred income tax expense in 2009 included the effects of one time recoveries of $19 million due to British Columbia corporate income tax rate reductions.

(3) Excludes the impact of current and deferred PRT expense and other current income tax expense.

(4) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

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

During 2011, the Canadian Federal government enacted legislation to implement several taxation changes. These changes include a requirement that, beginning in 2012, partnership income must be included in the taxable income of each corporate partner based on the tax year of the partner, rather than the fiscal year of the partnership. The legislation includes a five-year transition provision and has no impact on net earnings.

During 2011, the UK government enacted an increase to the supplementary income tax rate charged on profits from UK North Sea crude oil and natural gas production, increasing the combined corporate and supplementary income tax rate from 50% to 62%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $104 million. In its 2011 budget, the UK government announced its intention to restrict tax relief on decomisssioning expenditures to 50% for non-PRT fields and 75% for PRT fields. The proposed legislation to effect the restriction was released in 2011 for enactment in 2012. This proposed tax change would result in a deferred tax charge currently estimated at $56 million.

During 2010, deferred income tax expense included a charge of $132 million related to enacted changes in Canada to the taxation of stock options surrendered by employees for cash.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's results of operations, financial position or liquidity.

For 2012, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense of $700 million to $800 million in Canada and $200 million to $300 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES (1)

($ millions)	2011	2010	2009(5)
Exploration and Evaluation			
Net expenditures	$312	$572	$–
Property, Plant and Equipment			
Net property acquisitions	1,012	1,482	6
Land acquisition and retention	44	41	77
Seismic evaluations	47	51	73
Well drilling, completion and equipping	1,878	1,499	1,244
Production and related facilities	1,690	1,122	977
Capitalized interest	13	–	–
Net expenditures	4,684	4,195	2,377
Total Exploration and Production	4,996	4,767	2,377
Oil Sands Mining and Upgrading:			
Horizon Phase 1 construction and commissioning costs and other	–	–	271
Horizon Phases 2/3 construction costs	481	319	104
Sustaining capital	170	128	80
Turnaround costs	79	–	–
Capitalized interest, share-based compensation and other	48	96	98
Total Oil Sands Mining and Upgrading (2)	778	543	553
Horizon coker rebuild and collateral damage costs (3)	404	–	–
Midstream	5	7	6
Abandonments (4)	213	179	48
Head office	18	18	13
Total net capital expenditures	$6,414	$5,514	$2,997
By segment			
North America	$4,736	$4,369	$1,663
North Sea	227	149	168
Offshore Africa	33	249	546
Oil Sands Mining and Upgrading	1,182	543	553
Midstream	5	7	6
Abandonments (4)	213	179	48
Head office	18	18	13
Total	$6,414	$5,514	$2,997

(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) The Company recognized $393 million of property damage insurance recoveries (see note 10 to the Company's consolidated financial statements), offsetting the costs incurred related to the Coker rebuild and collateral damage costs.
(4) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.
(5) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

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 areas. 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 owning associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures for 2011 were $6,414 million compared to $5,514 million for 2010 (2009 – $2,997 million). The increase in capital expenditures from 2010 was primarily due to an increase in well drilling and completion expenditures related to the Company's record heavy crude oil drilling program, an increase in the Company's abandonment program, and costs associated with the coker rebuild and collateral damage resulting from the coker fire, partially offset by lower property acquisitions.

Drilling Activity (number of wells)

	2011	2010	2009
Net successful natural gas wells	83	92	109
Net successful crude oil wells (1)	1,103	934	644
Dry wells	48	33	46
Stratigraphic test / service wells	657	491	329
Total	1,891	1,550	1,128
Success rate (excluding stratigraphic test / service wells)	96%	97%	94%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 77% of the total capital expenditures for 2011 compared to approximately 83% for 2010 (2009 – 58%).

During 2011, the Company targeted 86 net natural gas wells, including 15 wells in Northeast British Columbia, 57 wells in Northwest Alberta and 14 wells in the Northern Plains. The Company also targeted 1,147 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 783 primary heavy crude oil wells, 66 Pelican Lake heavy crude oil wells, 19 light crude oil wells and 156 bitumen (thermal oil) wells were drilled. Another 123 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 and low natural gas prices, 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 2011, the Company drilled 141 bitumen (thermal oil) wells, and 111 stratigraphic test wells and observation wells. Overall Primrose thermal production for 2011 averaged approximately 98,000 bbl/d, compared to approximately 90,000 bbl/d in 2010 (2009 – 64,000 bbl/d).

The next planned phase of the Company's in situ Oil Sands Assets expansion is the Kirby South Phase 1 Project. During 2010, the Company received final regulatory approval for Phase 1 of the Project, and the Company's Board of Directors sanctioned Kirby South Phase 1. Construction has commenced, with first steam targeted in 2013. Drilling has been completed on the second of seven pads and has commenced on the third pad.

The Company continued to develop the tertiary recovery conversion projects at Pelican Lake throughout 2011. Pelican Lake production averaged approximately 38,000 bbl/d in 2011 (2010 – 38,000 bbl/d; 2009 – 37,000 bbl/d).

For 2012, planned crude oil drilling activity in North America is comprised of 1,114 net crude oil and bitumen wells and 45 net natural gas wells, excluding stratigraphic and service wells. As a result of lower 2012 natural gas prices than originally anticipated, the Company has reduced its planned natural gas capital expenditures by approximately $170 million, reducing North America natural gas production by approximately 20 MMcf/d.

Oil Sands Mining and Upgrading

Phase 2/3 spending during 2011 continued to be focused on final construction and pre-commissioning of the third ore preparation plant and associated hydro-transport, as well as additional product tankage, the butane treatment unit and the sulphur recovery unit. Final commissioning of the ore preparation plant and associated hydro-transport was completed in January 2012.

Due to property damage resulting from a fire in the primary upgrading coking plant at January 6, 2011, the Company recognized a Horizon asset impairment provision of $396 million, net of accumulated depletion and amortization. Insurance proceeds of $393 million were also recognized, offsetting such property damage. Production resumed in August 2011.

The Company has finalized its property damage insurance claim with certain of its insurers. The Company believes that the remaining portion of the property damage insurance claim will be settled without any significant adjustments from the $393 million currently recognized. The Company also maintains business interruption insurance to reduce operating losses related to its ongoing Horizon operations. The Company finalized its business interruption insurance claim related to the fire for proceeds of $333 million.

Subsequent to December 31, 2011, the Company temporarily suspended synthetic crude oil production at Horizon on February 5, 2012 to complete unplanned maintenance on the fractionating unit in the primary upgrading facility. The Company has targeted mid to late March to return to full production levels.

North Sea

During 2011, the Company incurred drilling and capital expenditures on the three Ninian platforms, facilities upgrade projects at Lyell and ongoing capital turnaround projects at Tiffany and Murchison.

In December 2011, the Banff FPSO and subsea infrastructure suffered storm damage. Operations at Banff/Kyle, with combined net production of approximately 3,500 bbl/d, were suspended and appropriate shut down procedures were activated. The FPSO and associated floating storage unit were subsequently removed from the field. All personnel on board the FPSO were safe and accounted for. The extent of the damage, including associated costs and timing of returning to the field, is currently being assessed.

In March 2011, the UK government enacted an increase to the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%. This resulted in an increase to the overall corporate tax rate applicable to net operating income from oil and gas activities to 62% for non-PRT paying fields and 81% for PRT paying fields, after allowing for deductions for capital and abandonment expenditures. As a result of the increase in the corporate income tax rate, the Company’s development activities in 2011 in the North Sea were reduced. The Company is continuing to high grade all North Sea prospects for potential development opportunities in 2012 and future years.

Offshore Africa

During 2011, the Company sanctioned an 8 well drilling program at the Espoir field in Cote d’Ivoire. Preparations are ongoing and a rig has been contracted to commence drilling operations targeted for late 2012.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	2011	2010	2009(8)
Working capital (deficit) (1)	$(894)	$(1,200)	$(514)
Long-term debt (2) (3)	$8,571	$8,485	$9,658
Shareholders’ equity			
Share capital	$3,507	$3,147	$2,834
Retained earnings	19,365	17,212	16,696
Accumulated other comprehensive (loss) income	26	9	(104)
Total	$22,898	$20,368	$19,426
Debt to book capitalization (3) (4)	27%	29%	33%
Debt to market capitalization (3) (5)	17%	15%	19%
After-tax return on average common shareholders’ equity (6)	12%	8%	8%

After-tax return on average capital employed (7)	10%	7%	6%

(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 (2011 – $359 million; 2010 – $397 million; 2009 – $nil).
(3) Long-term debt 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 twelve month trailing period; as a percentage of average common shareholders' equity for the year.
(7) Calculated as net earnings plus after-tax interest and other financing costs for the twelve month trailing period; as a percentage of average capital employed for the year.
(8) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

At December 31, 2011, 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 and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of this MD&A. In addition, the Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon 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.

During 2011, the Company filed base shelf prospectuses that allow 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 2013. Subsequently, the Company issued US$1,000 million of unsecured notes under the US base shelf prospectus, comprised of US$500 million of 1.45% unsecured notes due November 2014 and US$500 million of 3.45% unsecured notes due November 2021. Concurrently, the Company entered into cross currency swaps to fix the Canadian dollar interest and principal repayment amounts on the US$500 million of 3.45% unsecured notes due November 2021 at 3.96% and C$511 million. Proceeds from the securities issued were used to repay bank indebtedness under the Company's bank credit facilities. After issuing these securities, the Company has US$2,000 million remaining on its outstanding US$3,000 million base shelf prospectus. If issued, these securities will bear interest as determined at the date of issuance.

During 2011, the Company repaid US$400 million of US dollar denominated debt securities bearing interest at 6.70%, and the $2,230 million revolving syndicated credit facility was increased to $3,000 million and extended to June 2015. The $1,500 million revolving syndicated credit facility is currently maturing in June 2012. Each of the $3,000 million and $1,500 million facilities is extendible annually for one year periods at the mutual agreement of the Company and the lenders. During 2010, the Company repaid $400 million of the medium-term notes bearing interest at 5.50%. At December 31, 2011, the Company had $3,795 million of available credit under its bank credit facilities.

Long-term debt was $8,571 million at December 31, 2011, resulting in a debt to book capitalization ratio of 27% (December 31, 2010 – 29%; December 31, 2009 – 33%). 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, or lower commodity prices occurs. 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, adequate available liquidity and a flexible capital structure. The Company has hedged a portion of its crude oil production for 2012 at prices that protect investment returns to ensure ongoing balance sheet strength and the completion of its capital expenditure programs. Further details related to the Company's long-term debt at December 31, 2011 are discussed in note 8 to the Company's consolidated financial statements.

The Company's commodity hedging policy reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs. This policy 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 policy, the purchase of put options is in addition to the above parameters. As at March 6, 2012, approximately 40% of currently forecasted 2012 crude oil volumes were hedged using collars and puts. Further details related to the Company's commodity related derivative financial instruments outstanding at December 31, 2011 are discussed in note 17 to the Company's consolidated financial statements.

Share Capital

As at December 31, 2011, there were 1,096,460,000 common shares outstanding and 73,486,000 stock options outstanding. As at March 6, 2012, the Company had 1,100,567,000 common shares outstanding and 67,574,000 stock options outstanding.

On March 6, 2012, the Company's Board of Directors approved an increase in the annual dividend to be paid by the Company to $0.42 per common share for 2012. The increase represents an approximately 17% increase from 2011, 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 2011, an increase in the annual dividend paid by the Company to $0.36 per common share was approved for 2011. The increase represented a 20% increase from 2010.

On March 31, 2011, 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, 2011 and ending April 5, 2012, up to 27,406,131 common shares or 2.5% of the common shares of the Company outstanding at March 25, 2011. As at December 31, 2011, 3,071,100 common shares had been purchased for cancellation at an average price of $33.68 per common share, for a total cost of $104 million.

In 2010, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the TSX and 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. A total of 2,000,000 common shares were purchased for cancellation under this Normal Course Issuer Bid at an average price of $33.77 per common share, for a total cost of $68 million.

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, 2011, no entities were consolidated under the Standing Interpretations Committee ("SIC") 12, "Consolidation – Special Purpose Entities". The following table summarizes the Company's commitments as at December 31, 2011:

($ millions)	2012	2013	2014	2015	2016	Thereafter
Product transportation and pipeline	$ 247	$ 210	$ 199	$ 185	$ 123	$ 888
Offshore equipment operating leases	$ 118	$ 101	$ 100	$ 82	$ 53	$ 119
Long-term debt (1)	$ 356	$ 806	$ 865	$ 1,196	$ 255	$ 5,135
Interest and other financing costs (2)	$ 442	$ 403	$ 384	$ 339	$ 321	$ 4,116
Office leases	$ 30	$ 33	$ 34	$ 32	$ 33	$ 305
Other	$ 288	$ 158	$ 88	$ 24	$ 2	$ 8

(1) Long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs.

(2) Interest and other financing cost amounts represent the scheduled fixed rate and variable rate cash interest payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates and foreign exchange rates as at December 31, 2011.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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.

RESERVES

For the years ended December 31, 2011 and 2010, the Company retained Independent Qualified Reserves Evaluators to evaluate and review all of the Company's proved and 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 was granted an exemption from certain provisions of NI 51-101 allowing the Company to substitute SEC requirements under Regulations S-K and S-X for certain disclosures required under NI 51-101. Such exemption expired on December 31, 2010.

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, 2011, 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, 2010	482	160	239	919	1,932	4,262	63	4,505
Discoveries	–	1	–	–	–	7	–	2
Extensions	7	47	8	20	–	220	18	137
Infill Drilling	8	8	–	2	–	55	3	30
Improved Recovery	–	1	–	–	–	–	–	1
Acquisitions	2	–	–	–	–	432	7	81
Dispositions	–	–	–	–	–	–	–	–
Economic Factors	28	–	–	–	4	(174)	(1)	3
Technical Revisions	(44)	(4)	43	69	198	104	12	291
Production	(32)	(38)	(14)	(36)	(15)	(459)	(7)	(219)
December 31, 2011	451	175	276	974	2,119	4,447	95	4,831

Proved plus Probable 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, 2010	703	217	348	1,702	2,888	5,767	83	6,902
Discoveries	–	1	–	–	–	8	–	2
Extensions	10	69	14	37	388	342	29	605
Infill Drilling	11	12	–	3	–	109	7	51
Improved Recovery	1	4	–	–	–	–	–	5
Acquisitions	2	–	–	–	–	536	9	100
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	2	–	–	–	4	(208)	(2)	(30)
Technical Revisions	(28)	(16)	40	20	90	7	15	122
Production	(32)	(38)	(14)	(36)	(15)	(459)	(7)	(219)
December 31, 2011	669	249	388	1,726	3,355	6,101	134	7,538

At December 31, 2011, the Company's gross proved crude oil and NGLs reserves totaled 4,090 MMbbl, and gross proved plus probable crude oil and NGLs reserves totaled 6,521 MMbbl. Proved reserve additions and revisions replaced 308% of 2011 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 437 MMbbl, and additions to proved plus probable reserves amounted to 722 MMbbl. Net positive revisions amounted to 305 MMbbl for proved reserves and 125 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, partially offset by negative revisions in the North Sea due to cancellation of certain of the Company's activities that became uneconomic as a result of changes in the UK fiscal structure.

At December 31, 2011, the Company's gross proved natural gas reserves totaled 4,447 Bcf, and gross proved plus probable natural gas reserves totaled 6,101 Bcf. Proved reserve additions and revisions replaced 140% of 2011 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 644 Bcf, and additions to proved plus probable reserves amounted to 793 Bcf. Net negative revisions amounted to 70 Bcf for proved reserves and 201 Bcf for proved plus probable reserves, primarily due to lower estimated future benchmark 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.

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 the exploration, development, production and marketing of 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 and volatility 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 properties and/or 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. 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 2011, the Company's capital expenditures included $213 million for abandonment expenditures (2010 – $179 million; 2009 – $48 million). The Company's estimated discounted ARO at December 31, 2011 was as follows:

	December 31 2011	December 31 2010
Exploration and Production		
North America	$ 1,862	$ 1,390
North Sea	723	670
Offshore Africa	192	137
Oil Sands Mining and Upgrading	798	426

Midstream	2	1
	$3,577	$2,624

The discounted ARO was based on estimates of future costs to abandon and restore wells, production facilities, mine site, upgrading facilities and tailings, and offshore production platforms. Factors that affect costs include number of wells drilled, well depth, facility size and the specific environmental legislation. The estimated future costs are based on engineering estimates of current costs in accordance with present legislation, industry operating practice and the expected timing of abandonment. 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.

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 is also 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 are subject to compliance under the regulations. In the province of British Columbia, carbon tax is currently being assessed at $25/tonne of CO2e on fuel consumed and gas flared in the province. This rate is scheduled to increase to $30/tonne on July 1, 2012. As part of its involvement with the Western Climate Initiative, British Columbia may require certain upstream oil and gas facilities to participate in a regional cap and trade system. If such a system is implemented, it is not expected to be in place before 2014. It is estimated that four 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 released draft GHG regulations that regulate facilities emitting more than 50 kilotonnes of CO2e annually and will likely require the North Tangleflags in situ heavy oil facility to meet the reduction target for its GHG emissions once the governing legislation comes into force. 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. In Phase 3 (2013 – 2020) the Company's CO2 allocation is expected to be further reduced, although details on Phase 3 have not yet been finalized. 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.

The United States Environmental Protection Agency ("EPA") is proceeding to regulate GHGs under the Clean Air Act. This EPA action has been 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, 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.

The additional requirements of enacted or proposed GHG regulations on the Company's operations will increase capital expenditures and operating expenses, including those related to Horizon and the Company's other existing and certain planned oil sands projects. This may have an adverse effect on the Company's future 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 are being developed that adopt a structured process to emission reductions that is commensurate with technological development and operational requirements.

CRITICAL ACCOUNTING ESTIMATES AND CHANGE IN ACCOUNTING POLICIES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements that have a significant impact on the financial results of the Company. Actual results could differ from estimated amounts, and those differences may be material.

Critical accounting estimates are reviewed by the Company's Audit Committee annually. The Company believes the following are the most critical accounting estimates in preparing its consolidated financial statements.

Depletion, Depreciation and Amortization and Impairment

Exploration and evaluation ("E&E") asset costs relating to activities to explore and evaluate crude oil and natural gas properties are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. Exploration and evaluation assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined. Technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when proved reserves are determined to exist. The judgements associated with the estimation of proved reserves are described below in "Crude Oil and Natural Gas Reserves".

An alternative acceptable accounting method for E&E assets under IFRS 6 "Exploration for and Evaluation of Mineral Resources" is to charge exploratory dry holes and geological and geophysical exploration costs incurred after having obtained the legal rights to explore an area against net earnings in the period incurred rather than capitalizing to E&E assets.

E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of Cash Generating Units ("CGUs"), aggregated at the segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions of estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. The determination of the fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and production costs. Changes in any of these assumptions, such as a downward revision in probable reserves volumes, decrease in commodity prices or increase in costs, could impact the fair value.

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. Crude oil and natural gas properties in the Exploration and Production segments are depleted using the unit-of-production method over proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future estimated development expenditures required to develop proved reserves. Estimates of proved reserves have a significant impact on net earnings, as they are a key input to the calculation of depletion expense.

The Company assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low commodity prices for an extended period, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If any such indication of impairment exists, the Company performs an impairment test related to the specific assets. Individual assets are grouped for impairment assessment purposes into CGU's, which are the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. The determination of fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and production costs. Changes in any of these assumptions, such as a downward revision in reserves, decrease in commodity prices or increase in costs, could impact the fair value.

Crude Oil and Natural Gas Reserves

The estimation of reserves involves the exercise of judgement. Reserve estimates are based on engineering data, estimated future prices, expected future rates of production and the cost and 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, and may be affected by changes in commodity prices. 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 depletion, depreciation and amortization 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 and E&E carrying amounts.

Asset Retirement Obligations

The Company is required to recognize a liability for ARO 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 present values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. The provision for 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 4.6%. Subsequent to initial measurement, the ARO is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes in discount rates or the estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Changes in estimates would impact accretion and depletion expense in net earnings. 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, deferred income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences in the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted as at the date of the balance sheet. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes liabilities for potential tax audit issues based on assessments of whether additional taxes will be due.

Risk Management Activities

The Company uses 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 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. In determining these assumptions, the Company uses directly and indirectly observable inputs in measuring the value of financial instruments that are not traded in active markets, 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.

Purchase Price Allocations

Purchase prices related to 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, including the fair value of crude oil and natural gas properties. 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 depletion, depreciation and amortization 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 judgements 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 judgements 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.

Share-based compensation

The Company has made various assumptions in estimating the fair values of stock options granted including expected volatility, expected exercise behavior and future forfeiture rates. At each period end, stock options outstanding are remeasured each reporting period for subsequent changes in the fair value of the liability.

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, 2011, 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, 2011, 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 2011 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.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

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

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In 2010, the CICA Handbook was revised to incorporate IFRS and require publicly accountable enterprises to apply IFRS effective for years beginning on or after January 1, 2011. The 2011 fiscal year is the first year in which the Company has prepared its consolidated financial statements in accordance with IFRS as issued by the IASB.

The accounting policies adopted by the Company under IFRS are set out in note 1 to the Company's consolidated financial statements and are based on IFRS issued and outstanding as at December 31, 2011. Subject to certain transition elections disclosed in note 22 to the Company's consolidated financial statements, the Company has consistently applied the same accounting policies in its opening IFRS balance sheet at January 1, 2010 and throughout all periods presented, as if these policies had always been in effect.

Unless otherwise stated, comparative figures for 2010 have been restated from Canadian GAAP to comply with IFRS. Note 22 to the Company's consolidated financial statements discloses the impact of the transition to IFRS on the Company's reported financial position, net earnings and cash flows, including the nature and effect of significant changes in accounting policies from those used in the Company's Canadian GAAP consolidated financial statements for the year ended December 31, 2010.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

The Company is required to adopt IFRS 9, "Financial Instruments", effective January 1, 2015, with earlier adoption permitted. IFRS 9 replaces existing requirements included in IAS 39, "Financial Instruments - Recognition and Measurement". The new standard replaces the multiple classification and measurement models for financial assets and liabilities with a new model that has only two categories: amortized cost and fair value through profit and loss. Under IFRS 9, fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income.

In May 2011, the IASB issued the following new accounting standards, which are required to be adopted effective January 1, 2013:

§ IFRS 10 "Consolidated Financial Statements" replaces IAS 27 "Consolidated and Separate Financial Statements" (IAS 27 still contains guidance for Separate Financial Statements) and Standing Interpretations Committee ("SIC") 12 "Consolidation – Special Purpose Entities". IFRS 10 establishes the principles for the presentation and preparation of consolidated financial statements. The standard defines the principle of control and establishes control as the basis for consolidation, as well as providing guidance on how to apply the control principle to determine whether an investor controls an investee.

§ IFRS 11 "Joint Arrangements" replaces IAS 31 "Interests in Joint Ventures" and SIC 13 "Jointly Controlled Entities – Non-Monetary Contributions by Venturers". The new standard defines two types of joint arrangements, joint operations and joint ventures, and prescribes the accounting treatment for each type of joint arrangement – recognition of the proportionate interest in the assets, liabilities, revenues and expenses; and equity accounting, respectively. There is no longer a choice of the accounting method.

§ IFRS 12 "Disclosure of Interests in Other Entities". The standard includes disclosure requirements for investments in subsidiaries, joint arrangements, associates and unconsolidated structured entities. This standard does not impact the Company's accounting for investments in other entities, but will impact the related disclosures.

§ IFRS 13 "Fair Value Measurement" provides guidance on how fair value should be applied where its use is already required or permitted by other standards within IFRS. The standard includes a definition of fair value and a single source of fair value measurement and disclosure requirements for use across all IFRSs that require or permit the use of fair value.

In June 2011, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" that require items of other comprehensive income that may be reclassified to net earnings to be grouped together. The amendments also require that items in other comprehensive income and net earnings be presented as either a single statement or two consecutive statements. The standard is effective for fiscal years beginning on or after July 1, 2012.

In October 2011, the IASB issued IFRS Interpretation Committee ("IFRIC") 20 "Stripping Costs in the Production Phase of a Surface Mine". The IFRIC requires overburden removal costs during the production phase to be capitalized and depreciated if the Company can demonstrate that probable future economic benefits will be realized, the costs can be reliably measured, and the Company can identify the component of the ore body for which access has been improved. The IFRIC is effective for fiscal periods beginning on or after January 1, 2013.

The Company is currently assessing the impact of these new and amended standards on its consolidated financial statements. The Company does not plan to early adopt the above noted standards.

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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 targets production levels in 2012 to average between 440,000 bbl/d and 480,000 bbl/d of crude oil and NGLs and between 1,247 MMcf/d and 1,297 MMcf/d of natural gas.

Capital expenditures in 2012 are currently targeted to be as follows:

($ millions)	2012 Guidance
Exploration and Production	
North America natural gas	$645
North America crude oil and NGLs	2,010
North America bitumen (thermal oil)	
Primrose and future	940
Kirby South Phase 1	480
North Sea and Offshore Africa	480
Property acquisitions, dispositions and midstream	135
	$4,690
Oils Sands Mining and Upgrading	
Project capital	
Reliability – Tranche 2	145
Directive 74 and Technology	190
Phase 2A	300
Phase 2B	625
Phase 3	420
Phase 4	30
Owner’s Costs and Other	240
Total capital projects	$1,950
Sustaining capital	225
Turnarounds and reclamation	45
Capitalized interest and other	135
Total	$2,355

The above capital expenditure budget incorporates the following levels of drilling activity:

(Number of wells)	2012 Guidance
Targeting natural gas	45
Targeting crude oil	1,115
Stratigraphic test / service wells – Exploration and Production	584
Stratigraphic test wells – Oil Sands Mining and Upgrading	230
Total	1,974

North America Natural Gas

The 2012 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)	2012 Guidance
Conventional natural gas	4
Cardium natural gas	1
Deep natural gas	40
Total	45

33

North America Crude Oil and NGLs

The 2012 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)	2012 Guidance
Primary heavy crude oil	808
Bitumen (thermal oil)	159
Light and medium crude oil	134
Pelican Lake heavy crude oil	13
Total	1,114

Oil Sands Mining and Upgrading
During 2012, Phase 2/3 will continue to progress engineering and construction activities with respect to extraction, froth treatment, hydrotreatment, the butane storage unit, tailings and the vacuum unit in accordance with the overall Phase 2/3 execution schedule and strategy.

North Sea
During 2012, the majority of capital expenditures will be incurred to complete necessary sustaining capital activities on North Sea platforms.

Offshore Africa
During 2012, the majority of capital expenditures will be incurred on drilling and completions at the Espoir field.

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 2011, 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	$102	$0.09	$102	$0.09
Including financial derivatives	$102	$0.09	$102	$0.09
Natural gas – AECO C$0.10/Mcf (1)				
Excluding financial derivatives	$21	$0.02	$21	$0.02
Including financial derivatives	$21	$0.02	$21	$0.02
Volume changes				
Crude oil – 10,000 bbl/d	$171	$0.16	$130	$0.12
Natural gas – 10 MMcf/d	$6	$0.01	$–	$–

Foreign currency rate change				
$0.01 change in US$ (1)				
Including financial derivatives	$97 – 99	$0.09	$55 – 56	$0.05
Interest rate change – 1%	$6	$0.01	$6	$0.01

(1) For details of financial instruments in place, refer to note 17 to the Company's consolidated financial statements as at December 31, 2011.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2011	2010	2009
Crude oil and NGLs (bbl/d)							
North America – Exploration and Production	290,130	295,715	304,671	291,839	295,618	270,562	234,523
North America – Oil Sands Mining and Upgrading	7,269	–	50,354	102,952	40,434	90,867	50,250
North Sea	34,101	32,866	26,350	26,769	29,992	33,292	37,761
Offshore Africa	25,488	21,334	22,525	22,726	23,009	30,264	32,929
Total	356,988	349,915	403,900	444,286	389,053	424,985	355,463
Natural gas (MMcf/d)							
North America	1,225	1,218	1,226	1,255	1,231	1,217	1,287
North Sea	9	7	5	6	7	10	10
Offshore Africa	22	15	21	19	19	16	18
Total	1,256	1,240	1,252	1,280	1,257	1,243	1,315
Barrels of oil equivalent (BOE/d)							
North America – Exploration and Production	494,223	498,658	509,080	500,984	500,778	473,447	449,054
North America – Oil Sands Mining and Upgrading	7,269	–	50,354	102,952	40,434	90,867	50,250
North Sea	35,563	34,048	27,161	27,688	31,082	34,973	39,444
Offshore Africa	29,176	23,833	25,980	25,975	26,232	32,904	35,982
Total	566,231	556,539	612,575	657,599	598,526	632,191	574,730

PER UNIT RESULTS – EXPLORATION AND PRODUCTION (1)

	Q1	Q2	Q3	Q4	2011	2010	2009(3)
Crude oil and NGLs ($/bbl)							
Sales price (2)	$67.96	$82.58	$73.80	$85.28	$77.46	$65.81	$57.68
Royalties	10.43	11.62	11.52	15.53	12.30	10.09	6.73
Production expense	14.30	15.38	16.42	16.85	15.75	14.16	15.92
Netback	$43.23	$55.58	$45.86	$52.90	$49.41	$41.56	$35.03
Natural gas ($/Mcf)							
Sales price (2)	$3.83	$3.83	$3.76	$3.50	$3.73	$4.08	$4.53
Royalties	0.13	0.24	0.17	0.18	0.18	0.20	0.32
Production expense	1.17	1.11	1.15	1.15	1.15	1.09	1.08
Netback	$2.53	$2.48	$2.44	$2.17	$2.40	$2.79	$3.13
Barrels of oil equivalent ($/BOE)							
Sales price (2)	$51.33	$60.77	$55.19	$61.21	$57.16	$49.90	$44.87
Royalties	6.87	7.83	7.59	10.14	8.12	6.72	4.72
Production expense	11.59	12.12	12.83	13.12	12.42	11.25	11.98
Netback	$32.87	$40.82	$34.77	$37.95	$36.62	$31.93	$28.17

(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) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

PER UNIT RESULTS – OIL SANDS MINING AND UPGRADING (1)

	Q1	Q2	Q3	Q4	2011	2010	2009(5)
Crude oil and NGLs($/bbl)							
SCO sales price (2)	$82.93	$–	$96.19	$103.16	$99.74	$77.89	$70.83
Bitumen royalties (3)	4.14	–	3.48	4.21	3.99	2.72	2.15
Production expense (4)	45.69	–	35.85	36.04	36.64	36.36	39.89
Netback	$33.10	$–	$56.86	$62.91	$59.11	$38.81	$28.79

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and excluding risk management activities.
(3) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.
(4) Amounts expressed on a per unit basis in 2011 are based on sales volumes excluding the period during suspension of production.
(5) Comparative amounts for 2009 are reported in accordance with Canadian generally accepted accounting principles as previously reported.

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2011	2010
TSX – C$						
Trading volume (thousands)					800,044	661,832
Share Price ($/share)						
High	$50.50	$48.41	$42.14	$39.41	$50.50	$45.00
Low	$40.05	$37.43	$29.80	$27.25	$27.25	$31.97
Close	$47.94	$40.43	$30.77	$38.15	$38.15	$44.35
Market capitalization as at December 31 ($ millions)					$41,830	$48,379
Shares outstanding (thousands)					1,096,460	1,090,848
NYSE – US$						
Trading volume (thousands)					937,481	759,327
Share Price ($/share)						
High	$52.04	$50.25	$44.12	$38.72	$52.04	$44.77
Low	$40.42	$38.18	$28.77	$25.69	$25.69	$30.00
Close	$49.43	$41.86	$29.27	$37.37	$37.37	$44.42
Market capitalization as at December 31 ($ millions)					$40,975	$48,455
Shares outstanding (thousands)					1,096,460	1,090,848

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, 2011, 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, 2011, 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 Auditor's Report" that accompanies Canadian Natural's audited consolidated financial statements for the fiscal year ended December 31, 2011, 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, 2011, 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, principal financial officer, principal accounting officer or controller and persons performing similar functions, 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, 2011 and December 31, 2010, for professional services rendered by PwC for the audit of its internal controls and annual consolidated financial statements in connection with statutory and regulatory filings or engagements for those fiscal years, unaudited reviews of the first, second and third quarters of its interim consolidated financial statements and audits of certain of Canadian Natural's subsidiary companies' annual financial statements were $2,696,000 for 2011 and were $3,001,500 for 2010.

Audit-Related Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ending December 31, 2011 and December 31, 2010, for audit-related services by PwC including debt covenant compliance, pension assets and Crown Royalty Statements, were $175,000 for 2011 and were $169,000 for 2010. 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, 2011 and December 31, 2010, for professional services rendered by PwC for tax services related to expatriate personal tax compliance and other corporate tax return matters were $156,000 for 2011 and were $149,000 for 2010. 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, 2011 and December 31, 2010 for other services were $9,000 for 2011 and were $54,100 for 2010. The fees for other services paid in 2011 related to accessing resource materials through PwC's accounting literature library. Canadian Natural's Audit Committee approved all of the noted services.

Audit Committee Pre-Approval Policies and Procedures

The Audit Committee's duties and responsibilities include the review and approval of fees to be paid to the independent auditors, scope and timing of the audit and other related services rendered by the independent auditors. The Audit Committee also reviews and approves the independent auditor's annual audit plan, including scope, staffing, locations and reliance upon management and internal audit department prior to the commencement of the audit and reviews and approves proposed non-audit services to be provided by the independent auditors, except those non-audit services prohibited by legislation. Canadian Natural did not rely on the de minimis exemption provided by paragraph (c)(7)(i)(c) of Rule 2.01 of Regulation S-X in 2011.

OFF BALANCE SHEET ARRANGEMENTS

The Company does not have any off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Tabular Disclosure of Contractual Obligations

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. The following table summarizes the Company's commitments as at December 31, 2011:

($ millions)	2012	2013	2014	2015	2016	Thereafter
Product transportation and pipeline	$ 247	$ 210	$ 199	$ 185	$ 123	$ 888
Offshore equipment operating leases	$ 118	$ 101	$ 100	$ 82	$ 53	$ 119
Long-term debt (1)	$ 356	$ 806	$ 865	$ 1,196	$ 255	$ 5,135
Interest and other financing costs (2)	$ 442	$ 403	$ 384	$ 339	$ 321	$ 4,116
Office leases	$ 30	$ 33	$ 34	$ 32	$ 33	$ 305
Other	$ 288	$ 158	$ 88	$ 24	$ 2	$ 8

(1) Long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs.

(2) Interest and other financing cost amounts represent the scheduled fixed rate and variable rate cash interest payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates and foreign exchange rates as at December 31, 2011.

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 Ms. C.M. Best, who chairs the Audit Committee and Messrs. T. W. Faithfull, G. A. Filmon, G. D. Giffin, D. A. Tuer.

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 registrant.

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 27th day of March, 2012.

CANADIAN NATURAL RESOURCES LIMITED

By:	SIGNED “STEVE W. LAUT”
	Name: Steve W. Laut
	Title: President

Documents filed as part of this report:

EXHIBIT INDEX

Exhibit No.	Description
1.	Supplementary Oil & Gas Information for the fiscal year ended December 31, 2011.
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.