CNOOC LTD
Form 6-K
December 21, 2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 6-K

Report of Foreign Private Issuer

Pursuant to Rule 13a-16 or 15d-16
of the Securities Exchange Act of 1934

For the month of December 2012

Commission File Number 1-14966

CNOOC Limited
(Translation of registrant's name into English)

65th Floor
Bank of China Tower
One Garden Road
Central, Hong Kong
(Address of principal executive offices)

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F.

Form 20-F X Form 40-F ___

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1): ____

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7): ____

Indicate by check mark whether by furnishing the information contained in this Form, the registrant is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes ___ No X

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): Not applicable

Signature

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CNOOC Limited

| | |
|---|---|
| By: | /s/ Hua Zhong |
| Name: | Hua Zhong |
| Title: | Joint Company Secretary |

Dated: December 21, 2012

EXHIBIT INDEX

| Exhibit No. | Description |
|---|---|
| 99.1 | Circular dated December 20, 2012, entitled “Major Transaction in Relation to the Proposed Acquisition of Nexen”. |
| 99.2 | Announcement dated December 20, 2012, entitled “Notification Letter and Request Form for Non-Registered Holders”. |

Exhibit 99.1

THIS CIRCULAR IS IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION

If you are in any doubt as to any aspect of this circular or as to the action to be taken, you should consult your stockbroker or other registered dealer in securities, bank manager, solicitor, professional accountant or other professional adviser.

If you have sold or transferred all your shares in CNOOC Limited you should at once pass this circular to the purchaser or to the bank, stockbroker or other agent through whom the sale was effected for transmission to the purchaser.



(Incorporated in Hong Kong with limited liability under the Companies Ordinance)
(Stock Code: 00883)

MAJOR TRANSACTION
IN RELATION TO THE PROPOSED ACQUISITION OF NEXEN

A letter from the Board is set out from pages 8 to 27 of this circular.

20 December 2012

CONTENTS

## DEFINITIONS

In this circular, unless the context otherwise requires, the following expressions have the following meanings:

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| "Announcement" | the announcement dated 23 July 2012 made by the Company in relation to the Proposed Acquisition |
| "APEGA" | the Association of Professional Engineers and Geoscientists of Alberta |
| "Arrangement" | an arrangement under Section 192 of the CBCA on the terms and subject to the conditions set out in the Plan of Arrangement, subject to any amendments or variations to the Plan of Arrangement made in accordance with the terms of the Arrangement Agreement or made at the direction of the Court in the Final Order with the prior written consent of Nexen and the Purchaser, each acting reasonably |
| "Arrangement Agreement" | the agreement dated 23 July 2012, Canada local time (23 July 2012, Hong Kong time) entered into by the Company, the Purchaser and Nexen in relation to the Proposed Acquisition |
| "Arrangement Resolution" | the special resolution approving the Plan of Arrangement considered by holders of Common Shares at the Nexen company meeting |
| "Articles of Arrangement" | the articles of arrangement of Nexen in respect of the Arrangement, required by the CBCA to be sent to the director appointed pursuant to Section 260 of the CBCA after the Final Order is made, which shall include the Plan of Arrangement and otherwise be in a form and content satisfactory to Nexen and the Purchaser, each acting reasonably |
| "associate(s)" | has the meaning ascribed to it under the Listing Rules |
| "Board" | the board of Directors |
| "C$" or "Cdn$" | Canadian dollars, the lawful currency of Canada |
| "Canadian GAAP" | Canadian Generally Accepted Accounting Principles |
| "Canadian GAAS" | Canadian Generally Accepted Auditing Standards |
| "CBCA" | Canada Business Corporations Act |

## DEFINITIONS

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| "Certificate of Arrangement" | means the certificate of arrangement to be issued by the director appointed pursuant to Section 260 of the CBCA pursuant to Section 192(7) of the CBCA in respect of the Articles of Arrangement |
| "CICA" | Canadian Institute of Chartered Accountants |
| "CNOOC" | China National Offshore Oil Corporation , an indirect controlling shareholder of the Company holding approximately 64.45% of the Shares of the Company in issue through OOGC and CNOOC (BVI) as at the Latest Practicable Date |
| "COGEH" | Canadian Oil and Gas Evaluation Handbook prepared jointly by the SPEE (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time |
| "Collective Agreement" | all collective bargaining agreements or union agreements currently applicable to Nexen and/or any of its subsidiaries and all related documents, including letters of understanding, letters of intent and other written communications with bargaining agents for any Nexen Employee which impose any obligations upon Nexen and/or any of its subsidiaries |
| "Common Shares" | the common shares in the capital of Nexen |
| "Company" | CNOOC Limited, a company incorporated in Hong Kong with limited liability, whose shares are listed on the Hong Kong Stock Exchange and whose American depositary receipts are listed on the NYSE |
| "Controlling Shareholder" or "CNOOC (BVI)" | CNOOC (BVI) Limited, a company incorporated in the British Virgin Islands with limited liability |
| "Conditions" | the conditions precedent to completion of the Proposed Acquisition |
| "connected person(s)" | has the meaning ascribed to it under the Listing Rules |
| "Consideration" | the consideration of US$27.50 in cash per Common Share, without interest, and C$26.00 in cash per Preferred Share, together with accrued and unpaid dividends thereon up to, but excluding, the Effective Date, without interest, as applicable |

DEFINITIONS

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| "Court" | the Court of Queen's Bench of Alberta, or other court as applicable |
| "Deloitte Canada" | Deloitte & Touche LLP, Independent Registered Chartered Accountants, Canada |
| "Deloitte Hong Kong" | Deloitte Touche Tohmatsu, Certified Public Accountants, Hong Kong |
| "Director(s)" | the directors of the Company |
| "D&M" | DeGolyer and MacNaughton |
| "Effective Date" | the date shown on the Certificate of Arrangement giving effect to the Arrangement |
| "Effective Time" | 12:01 a.m. (Calgary local time) on the date shown on the Certificate of Arrangement giving effect to the Arrangement |
| "Enlarged Group" | the Group as enlarged by the Proposed Acquisition |
| "Final Order" | the final order of the Court approving the Plan of Arrangement |
| "Group" | the Company and its subsidiaries from time to time |
| "HK$" | Hong Kong dollars, the lawful currency of Hong Kong |
| "HKFRS" | Hong Kong Financial Reporting Standards |
| "Hong Kong" | the Hong Kong Special Administrative Region of the People's Republic of China |
| "Hong Kong Stock Exchange" | The Stock Exchange of Hong Kong Limited |
| "IFRS" | International Financial Reporting Standards |
| "Independent Reserves Evaluators" | the independent reserves evaluators engaged by Nexen to assess its reserves estimates |
| "Interim Order" | the interim order of the Court providing for, among other things, the calling and holding of the meeting of the holders of Common Shares and Preferred Shares |
| "IQRE" | the internal qualified reserves evaluator of Nexen |

DEFINITIONS

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| "Latest Practicable Date" | 17 December 2012, being the latest practicable date prior to the printing of this circular for ascertaining certain information herein |
| "Listing Rules" | the Rules Governing the Listing of Securities on The Stock Exchange of Hong Kong Limited |
| "McDaniel" | McDaniel & Associates Consultants Ltd. |
| "Nexen" | Nexen Inc., a company incorporated under the CBCA whose securities are listed on the TSX and the NYSE under the symbol NXY |
| "Nexen Board" | the board of directors of Nexen |
| "Nexen Constating Documents" | the restated articles of incorporation and by-laws of Nexen and all amendments to such articles or by-laws |
| "Nexen Employees" | the officers, employees and independent contractors of Nexen and its subsidiaries |
| "Nexen Group" | Nexen and its subsidiaries |
| "Nexen Shares" | collectively, the Common Shares and the Preferred Shares |
| "NI 51-101" | the Canadian National Instrument 51-101 "Standards of Disclosure of Oil and Gas Activities" of the Canadian Securities Administrators |
| "NYSE" | New York Stock Exchange |
| "OOGC" | Overseas Oil and Gas Corporation, Ltd., a company incorporated in Bermuda with limited liability, a direct wholly owned subsidiary of CNOOC, the sole shareholder of CNOOC (BVI), and a shareholder of the Company directly holding five Shares of the Company in issue as at the Latest Practicable Date |
| "Permitted Dividends" | in respect of Common Shares, a dividend not in excess of C$0.05 per Common Share per quarter consistent with Nexen's current practice (including with respect to timing), and in respect of the Preferred Shares, regular quarterly dividends payable on the Preferred Shares in accordance with the terms of such Preferred Shares, as set out in Nexen's Constating Documents |

## DEFINITIONS

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| "Plan of Arrangement" | the plan of arrangement, substantially in the form set out in Schedule A to the Arrangement Agreement and any amendments or variations thereto |
| "PRC" | the People's Republic of China, excluding for the purpose of this circular, Hong Kong, Macau and Taiwan |
| "Preferred Shareholder Resolution" | the special resolution approving the Plan of Arrangement considered by the holders of Preferred Shares at the Nexen company meeting |
| "Preferred Shares" | the second series of preferred shares in the capital of Nexen designated as "Cumulative Redeemable Class A Rate Reset Preferred Shares, Series 2", as constituted on the date of the Arrangement Agreement |
| "PRMS" | the Petroleum Resources Management System published by the Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council and the SPEE in March 2007 as amended from time to time |
| "Proposed Acquisition" | the proposed acquisition of all the Common Shares and, as the proposed acquisition has been approved by more than two-thirds of the votes cast by the holders of the Preferred Shares as one class, the Preferred Shares, by the Purchaser in accordance with the Arrangement Agreement |
| "Purchaser" | CNOOC Canada Holding Ltd., a wholly-owned subsidiary of the Company |
| "RMB" | the lawful currency of the PRC |
| "Ryder Scott" | Ryder Scott Company L.P. |
| "SEC" | U.S. Securities and Exchange Commission |
| "SFO" | the Securities and Futures Ordinance (Chapter 571 of the Laws of Hong Kong) |
| "Share(s)" | ordinary share(s) of HK$ 0.02 each in the share capital of the Company |
| "Shareholder(s)" | registered holder(s) of the Share(s) |
| "SPE" | the Society of Petroleum Engineers |

DEFINITIONS

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| "SPEE" | the Society of Petroleum Evaluation Engineers |
| "TSX" | Toronto Stock Exchange |
| "US$" | United States dollars, the lawful currency of United States of America |
| "2011 AIF" | Annual Information Form of Nexen for the year ended 31 December 2011 |

The estimates of contingent recoverable resource in this circular reflect Nexen's low, best, and high estimates. A "best estimate" is the estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50% confidence level that the actual quantities recovered will equal or exceed the estimate. The 'low estimate' and 'high estimate' are considered to be conservative and optimistic estimates of resources with 90% and 10% confidence, respectively. Contingent resources are quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies on resources may include, but are not limited to, factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. Specific contingencies precluding these contingent resources being classified as reserves include but are not limited to: future drilling program results, drilling and completions optimization, stakeholder and regulatory approval of future drilling and infrastructure plans, access to required infrastructure, economic fiscal terms, a lower level of delineation, the absence of regulatory approvals, detailed design estimates and near-term development plans, and general uncertainties associated with this early stage of evaluation. There is no certainty that it will be commercially viable to produce any portion of the resources.

For the purpose of illustration only, unless otherwise stated, in this circular, (i) the amounts denominated in C$ have been translated into HK$ at the exchange rate of C$1.00 to HK$7.66; and (ii) the amounts denominated in US$ have been translated into HK$ at the exchange rate of US$1.00 to HK$7.76, both being the exchange rates prevailing at the market closing on 20 July 2012. Such translations should not be construed as a representation that the relevant amounts have been, could have been, or could be converted at that or any other rate or at all.

Conversions of gas volumes to boe in this circular were made on the basis of 1 boe to 6 mcf of natural gas. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation.

## GLOSSARY

This glossary of technical terms contains terms used in this circular in connection with the Enlarged Group. As such, these terms and their meanings may not correspond to standard industry meaning or usage of these terms.

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| "/d" | per day |
| "AECO" | natural gas storage facility located in Alberta |
| "bbl" | barrel |
| "boe" | barrels-of-oil-equivalent |
| "Brent" | Dated Brent |
| "mboe" | thousand barrels-of-oil equivalent |
| "mcf" | thousand cubic feet |
| "mmboe" | million barrels-of-oil equivalent |
| "mmbtu" | million British thermal units |
| "NGL" | natural gas liquid |
| "NYMEX" | New York Mercantile Exchange |
| "PSC(tm)" | Premium Synthetic Crude(tm) |
| "WTI" | West Texas Intermediate |
| "%" | per cent |

LETTER FROM THE BOARD

(Incorporated in Hong Kong with limited liability under the Companies Ordinance)
(Stock Code: 00883)

Board of Directors

Executive Directors
Li Fanrong
Wu Guangqi

Non-executive Directors
Wang Yilin (Chairman)
Yang Hua (Vice Chairman)
Zhou Shouwei
Wu Zhenfang

Independent Non-executive Directors
Chiu Sung Hong
Lawrence J. Lau
Tse Hau Yin, Aloysius
Wang Tao

Registered office
65th Floor, Bank of China Tower
1 Garden Road
Hong Kong

20 December 2012

To the Shareholders

Dear Sir or Madam,

MAJOR TRANSACTION
IN RELATION TO THE PROPOSED ACQUISITION OF NEXEN

INTRODUCTION

Reference is made to the Announcement in relation to the Proposed Acquisition. On 23 July 2012, Canada local time (23 July 2012, Hong Kong time), the Company, the Purchaser and Nexen entered into the Arrangement Agreement in relation to the Proposed Acquisition by the Company (through its wholly-owned subsidiary, the Purchaser) of Nexen Shares pursuant to a Plan of Arrangement under the CBCA.

As further announced by the Company on 21 September 2012 that, on 20 September 2012 (Canada local time), the Court has granted the Final Order which approved the Plan of Arrangement pursuant to CBCA. The Final Order was granted following a meeting of

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Nexen's shareholders on the same day at which the Plan of Arrangement was approved by approximately 99% of the votes cast by the holders of the Common Shares. As approximately 87% of the votes cast by the holders of Preferred Shares also approved the Plan of Arrangement, the Plan of Arrangement will also include the Preferred Shares.

Nexen is listed on the TSX and the NYSE. Upon completion of the Proposed Acquisition, Nexen will become a wholly-owned subsidiary of the Company.

As one of the applicable percentage ratios calculated under Chapter 14 of the Listing Rules in respect of the Proposed Acquisition exceeds 25% but is less than 100%, the Proposed Acquisition will constitute a major transaction of the Company for the purposes of, and is subject to, the notification, publication and shareholders' approval requirements under the Listing Rules.

As no Shareholder of the Company is required to abstain from voting if the Company were to convene a general meeting for approving the Proposed Acquisition, and as the Company has obtained a written approval of the Proposed Acquisition from the Controlling Shareholder, which directly held approximately 64.45% of the issued and outstanding Shares as at the date of the Announcement, pursuant to Rule 14.44 of the Listing Rules, the Company is not required to convene a general meeting for approving the Proposed Acquisition.

The purpose of this circular is to provide you with, among other things, (i) further information in respect of the Proposed Acquisition; (ii) financial and other information of the Group; (iii) unaudited pro forma financial information of the Enlarged Group; (iv) financial and reserves information of Nexen; and (v) other information as required under the Listing Rules.

THE ARRANGEMENT AGREEMENT

Date

23 July 2012, Canada local time (23 July 2012 Hong Kong time)

Parties

(i) the Company

(ii) the Purchaser

(iii)Nexen

The Company confirms that, to the best of the Directors' knowledge, information and belief, having made all reasonable enquiries, as at the date of the Announcement, Nexen and its ultimate beneficial owners are third parties independent of the Company and are not connected persons of the Company or its subsidiaries or their respective associates.

Shares to be acquired

Pursuant to the Arrangement Agreement, the Company will (through its wholly-owned subsidiary, the Purchaser) acquire all of the Common Shares, and as the Preferred Shareholder Resolution has been passed, all of the Preferred Shares, through a Plan of Arrangement under the CBCA.

Consideration

The aggregate value of the Consideration of the Proposed Acquisition is approximately US$15.1 billion (approximately HK$117.2 billion), and is to be payable in cash. The Consideration is related to acquisition of common and preferred shares and settlement of share options of Nexen. The indebtedness of Nexen as at the date of the Announcement of approximately US$4.3 billion (approximately HK$33.6 billion) will remain outstanding. The Purchaser shall, immediately prior to the sending by Nexen of the Articles of Arrangement to the director appointed pursuant to Section 260 of the CBCA, provide the depositary with sufficient funds to be held in escrow to satisfy (i) the aggregate Consideration per Common Share as provided in the Plan of Arrangement; and (ii) as the Preferred Shareholder Resolution has been passed, the aggregate Consideration per Preferred Share.

If, on or after the date of the Arrangement Agreement, Nexen sets a record date for any dividend or other distribution on Nexen Shares (other than certain Permitted Dividends) that is prior to the Effective Time or Nexen pays any dividend or other distribution on Nexen Shares (other than certain Permitted Dividends) prior to the Effective Time: (i) to the extent that the amount of such dividends or distributions per Nexen Share do not exceed the applicable Consideration per Nexen Share, the applicable Consideration per Nexen Share shall be reduced by the amount of such dividends or distributions; and (ii) to the extent that the amount of such dividends or distributions per Nexen Share exceeds the applicable Consideration per Nexen Share, such excess amount shall be placed in escrow for the account of the Purchaser or another person designated by the Purchaser.

Basis of the Consideration

The Consideration of the Proposed Acquisition was determined after arm’s length negotiations between the Company and Nexen and with reference to recent market trading prices of the Common Shares and the Company’s view of the value of the assets and business of Nexen. The Consideration price of US$27.50 per Common Share represents a premium of 61% relative to the closing price of the Common Shares on the NYSE on 20 July 2012 and a premium of 66% relative to the volume weighted average price of the Common Shares over the 20 trading days ended 20 July 2012.

Employees

Unless otherwise agreed in writing between the parties, each of the Company and the Purchaser has covenanted and agreed that Nexen Employees shall be provided with compensation not less than, and benefits that are, in the aggregate, no less favorable than, those provided to such Nexen Employees immediately prior to the Effective Time.

Each of the Company and the Purchaser has covenanted and agreed to honor and comply in all material respects with the terms of all the existing employment agreements, change of control agreements and severance obligations of Nexen Group and all obligations of Nexen Group under any employee plans.

Each of the Company and the Purchaser has further covenanted and agreed to cause Nexen to allocate and pay out to Nexen Employees bonus amounts in respect of the calendar year ending 31 December 2012 in accordance with Nexen's customary year-end bonus practices consistently applied in accordance with prior years as determined by Nexen Board.

Each of the Company and the Purchaser has agreed and acknowledged that Nexen shall institute a special transition bonus program, and subject to completion of the Arrangement, each of the Company and the Purchaser has covenanted and agreed to cause Nexen to allocate and pay out to Nexen Employees bonus amounts pursuant to the terms of such bonus program as determined by Nexen Board.

The above terms shall not apply to any Nexen Employee who is covered by a Collective Agreement and instead, the terms and conditions of employment of each such Nexen Employee following the Effective Time shall be governed by the terms of the applicable Collective Agreement.

Guarantee

The Company has unconditionally and irrevocably guaranteed in favour of Nexen the due and punctual performance by the Purchaser of the Purchaser's obligations under the Arrangement Agreement.

Regulatory Approvals

Completion of the Proposed Acquisition is subject to receipt of applicable governmental and regulatory approvals by the relevant authorities in, among others, Canada, the European Union, the United States and the People's Republic of China. As soon as reasonably practicable after the date of the Arrangement Agreement, each party, or where appropriate, the parties jointly, shall identify any such approvals necessary to complete the Arrangement and make all notifications, filings, applications and submissions with governmental entities required or advisable.

Conditions

Mutual Conditions

The parties to the Arrangement Agreement are not required to complete the Arrangement unless each of the following Conditions, summarized below, is satisfied on or prior to the Effective Time, which Conditions may only be waived, in whole or in part, by the mutual consent of each of the parties:

(a) the Arrangement Resolution has been approved and adopted by the holders of Common Shares at the special meeting in accordance with the Interim Order;

(b) the Interim Order and the Final Order have each been obtained on terms consistent with the Arrangement Agreement;

(c) each of the key regulatory approvals (as set forth in the Arrangement Agreement) has been made, given or obtained on terms acceptable to Nexen, the Company and the Purchaser, each acting reasonably, and in the case of the Company and the Purchaser subject to compliance with their respective covenants in respect of the regulatory approvals and each such key regulatory approval is in force and has not been modified;

(d) no law is in effect that makes the consummation of the Arrangement illegal or otherwise prohibits or enjoins Nexen, the Company or the Purchaser from consummating the Arrangement;

(e) the Articles of Arrangement to be filed under the CBCA in accordance with the Arrangement Agreement shall be in a form and content satisfactory to Nexen and the Purchaser, each acting reasonably; and

(f) absence of certain actions or proceedings (whether by a governmental entity or any other person).

Additional Conditions to the Obligations of the Purchaser

The Purchaser is not required to complete the Arrangement unless each of the following Conditions, summarized below, is satisfied on or before the Effective Time:

(a) the representations and warranties of Nexen set forth in the Arrangement Agreement being true and correct as of the date of the Arrangement Agreement and at the Effective Time, subject, in most cases, to a material adverse effect standard;

(b) material compliance by Nexen with each of its covenants in the Arrangement Agreement;

(c) receipt of all regulatory approvals (other than key regulatory approvals) and all other third party consents, waivers and the similar approvals, subject to the standards and exceptions set forth in the Arrangement Agreement;

(d) rights of dissent have not been exercised with respect to more than 5% of the issued and outstanding Common Shares; and

(e) there shall not have been or occurred a material adverse effect on Nexen.

Additional Conditions to the Obligations of Nexen

Nexen is not required to complete the Arrangement unless each of the following Conditions, summarized below, is satisfied on or before the Effective Time:

(a) the representations and warranties of the Company and the Purchaser set forth in the Arrangement Agreement being true and correct as of the date of Arrangement Agreement and the Effective Time, subject, in most cases, to a material adverse effect standard; and

(b) material compliance by the Company and the Purchaser with each of its covenants in the Arrangement Agreement.

Effecting the Plan of Arrangement

The Proposed Acquisition will be effected by way of a Plan of Arrangement. The Plan of Arrangement involves a Court-supervised process and will be effected through the proceedings under the CBCA.

As announced by the Company on 21 September 2012 that, on 20 September 2012 (Canada local time), the Court has granted the Final Order which approved the Plan of Arrangement pursuant to CBCA. The Final Order was granted following a meeting of Nexen's shareholders on the same day at which the Plan of Arrangement was approved by approximately 99% of the votes cast by the holders of the Common Shares. As approximately 87% of the votes cast by the holders of Preferred Shares also approved the Plan of Arrangement, the Plan of Arrangement will also include the Preferred Shares.

Termination Date

Either the Company, the Purchaser or Nexen may terminate the Arrangement Agreement, among other events, if the Arrangement does not occur by 31 January 2013, subject, if certain regulatory approvals are not received, to any party's right to extend such date for successive periods of 15 days (but not in excess of 75 business days in the aggregate).

Non-Solicitation and Termination Fee

The Arrangement Agreement includes a non-solicitation covenant on the part of Nexen, subject to customary "fiduciary out" provisions that entitle Nexen to consider and accept an acquisition proposal that is a superior proposal, provided that the Purchaser has a right to match any superior proposal.

If the Arrangement Agreement is terminated under certain circumstances, including if Nexen enters into an agreement with respect to a superior proposal or if the Nexen Board changes, withdraws or modifies its recommendation with respect to the Proposed Acquisition, Nexen shall pay the Purchaser a termination fee in the amount of US$425 million.

Reverse Termination Fee

If the Arrangement Agreement is terminated solely as a result of the PRC approvals having not been obtained, the Purchaser shall pay Nexen a reverse termination fee in the amount of US$425 million.

INFORMATION ON THE COMPANY AND THE PURCHASER

The Group is China's largest producer of offshore crude oil and natural gas and one of the largest independent oil and gas exploration and production companies in the world. The Group mainly engages in exploration, development, production and sales of oil and natural gas. The Group's core operation areas are Bohai, Western South China Sea, Eastern South China Sea and East China Sea in offshore China. In overseas, the Group has oil and gas assets in Asia, Africa, North America, South America and Oceania. As of 31 December 2011, the Group owned net proved reserves of approximately 3.19 billion boe, and its average daily net production was 909,000 boe. The Group had 5,377 employees and total assets of approximately RMB384.26 billion.

The Purchaser is a limited liability company incorporated in Canada and is a wholly owned subsidiary of the Company. The principal business activity of the Purchaser is investment holding.

## INFORMATION OF NEXEN AND ITS PETROLEUM ASSETS

### Information of Nexen

To the best of the Directors' knowledge, information and belief, having made all reasonable enquiries, the following sets out the information relating to Nexen.

Nexen is an independent Canadian-based global energy company, listed on the TSX and the NYSE under the symbol NXY. Nexen adds value for shareholders through successful full-cycle oil and gas exploration and development, as well as leadership in ethics, integrity, governance and environmental stewardship.

Nexen currently focuses on three core businesses:

- Conventional Oil & Gas: Nexen has major positions in three of the world's most significant conventional basins – the UK North Sea, Offshore West Africa and the deep-water Gulf of Mexico. It is the second largest oil producer in the UK North Sea.

- Oil Sands: Nexen has an interest in more than 625,000 undeveloped acres (gross) in the Athabasca oil sands region, with net proved plus probable reserves of 1,350 million barrels and approximately 4 billion barrels of contingent recoverable oil sands resource. Nexen is a 65% owner and the operator of Long Lake, an integrated steam assisted gravity drainage (SAGD) and upgrading operation. Nexen also has a 7.23% interest in the Syncrude Canada oil sands mining and upgrading facility.

- Shale Gas: Shale gas is expected to be a source of growth for Nexen in the future. With 300,000 acres (gross) of shale gas lands in the Horn River, Cordova and Liard basins in northeastern British Columbia, it has enough resources to significantly increase Nexen's proved reserves. Nexen has a joint venture shale gas exploration project in Poland and is exploring for shale gas in Colombia.

Nexen had average production of 207 mboe/d (after royalties) in the second quarter of 2012. In accordance with the SEC rules, Nexen had 900 mmboe of proved reserves and 1,122 mmboe of probable reserves as of 31 December 2011. In addition, Nexen had best estimate contingent resources of 5.6 billion boe in accordance with NI 51-101, predominately in the Canadian oil sands, as of 31 December 2011.

Set out below are the net profits (both before and after taxation and extraordinary items) of Nexen, prepared under IFRS, for the two financial years immediately preceding the date of the Announcement:

| | For the financial year ended 31 December | | | |
|---|---|---|---|---|
| | 2011 | | 2010 | |
| | C$ million | HK$ Equivalent million | C$ million | HK$ Equivalent million |
| Net profits before taxation and extraordinary items | 1,723 | 13,193 | 1,130 | 8,652 |
| Net profits after taxation and extraordinary items | 697 | 5,337 | 1,127 | 8,629 |

As at 31 December 2011, the shareholders' equity of Nexen was approximately C$8,373 million (approximately HK$64,112 million).

Nexen is in material compliance with all host country laws, regulations and permits. Please refer to the 2011 AIF as set out in Appendix IV to this circular for the detailed information on the petroleum assets of Nexen.

Risks Relating to the Operations of Nexen

Nexen's operations are exposed to various risks, some of which are common to other operations in the oil and gas industry and some of which are unique to Nexen's operations. See the section entitled "Risk Factors" in the 2011 AIF of Nexen as set out in Appendix IV to this circular.

Long Term Prospects of Nexen

Nexen has several development and appraisal projects underway, and a large resource base to support long-term growth which is described in the 2011 AIF as set out in Appendix IV to this circular. Since then, on 2 April 2012, Nexen announced completion of the evaluation of its drilling success on the northeast fault block of the Appomattox structure. Nexen has demonstrated contingent recoverable resource in the northeast block of approximately 215 mmboe (50 mmboe net to Nexen), with a range of 120 to 370 mmboe (25 to 90 mmboe net to Nexen) of light oil (based on NI 51-101). Nexen holds a 20% interest in Appomattox and a 25% interest in Vicksburg and various other blocks in the area; Shell Gulf of Mexico Inc. ("Shell") holds the remaining interest and is operator.

Nexen and operator Shell plan to conduct additional exploration and appraisal activity in the Appomattox area during 2012 and extending into 2013. The current discovered resource has hub potential with production capacity of more than 100,000 barrels of oil equivalent per day. Nexen's Appomattox area discoveries enhances Nexen resource base at

Appomattox and complement its previous exploration successes at Rochelle, West Rochelle and Golden Eagle in the North Sea, Knotty Head in the Gulf of Mexico and Owowo South offshore West Africa.

Upon the completion of the Proposed Acquisition, the Company will implement and enhance Nexen's current planned capital expenditure program, thereby investing significant capital in Canada and in Nexen's other international assets. The Company will bring greater financial capacity to better realize the full potential of Nexen's significant resource base.

REASONS FOR THE PROPOSED ACQUISITION

The Group has been a significant investor in Canada since 2005, with total capital investment of C$2.8 billion. These investments include a stake in MEG Energy Inc. (www.megenergy.com), OPTI Canada Inc. (Nexen's partners in the Long Lake SAGD and Upgrader) and a 60% interest in Northern Cross (Yukon) Limited (www.northerncrossyukon.ca).

The acquisition of Nexen will expand the Group's overseas businesses and resource base in order to deliver long-term, sustainable growth. Nexen will complement the Group's large offshore production footprint in China and extends the Group's global presence with a high-quality asset base in many of the world's most significant producing regions – including Western Canada, the U.K. North Sea, the Gulf of Mexico and offshore Nigeria – focused on conventional oil and gas, oil sands and shale gas. In addition, Nexen management's current mandate will be expanded to include all of the Group's North American and Caribbean assets.

Taking into account the benefits of the Proposed Acquisition, the Board is of the view that the terms of the Proposed Acquisition are fair and reasonable and the Proposed Acquisition is in the interests of the Company and the Shareholders as a whole.

FINANCIAL EFFECT OF THE PROPOSED ACQUISITION ON THE GROUP

Upon completion, Nexen will become a subsidiary of the Company and their results will be consolidated with that of the Group. In light of the business potential of Nexen and the future prospect of the oil and gas industry, the Directors are of the view that the Proposed Acquisition would widen the earnings base of the Group.

Set out in Appendix III to this circular is the unaudited pro forma financial information of the Enlarged Group which illustrates the financial effect of the Proposed Acquisition on the assets and liabilities of the Group assuming completion had taken place on 30 June 2012. The unaudited pro forma financial information has been prepared based on the assumption that the Company will obtain and utilise external banking facility of US$6 billion (or approximately RMB37,949 million) and receive gross cash proceeds of approximately RMB37,691 million from corporate wealth management products and RMB17,809 million from time deposits with maturity over three months, which will mature on or before the completion of the Proposed Acquisition, to satisfy the cash consideration for the Proposed Acquisition. Based on the unaudited pro forma financial information in Appendix III to this circular, the total assets of the Group would increase from

approximately RMB414.2 billion to approximately RMB550.0 billion; and its total liabilities would increase from approximately RMB130.0 billion to approximately RMB266.2 billion, as a result of the Proposed Acquisition. Shareholders should note that the earnings contribution from Nexen after completion will depend on the future performance of Nexen, and the actual effect of the Proposed Acquisition on the assets and liabilities of the Group will depend on the financial position of Nexen as at the date of completion, which cannot be quantified as at the Latest Practicable Date.

FINANCIAL AND TRADING PROSPECT OF THE ENLARGED GROUP

The Group is one of the largest independent oil and gas exploration and production companies in the world with oil and gas assets in Asia, Africa, North America, South America and Oceania. In the first half of this year, the global economic situation was critical, and China’s economic growth encountered challenges. Under this environment, the Group actively sought opportunities amidst crisis, and realized steady growth in its different areas of business. The Group overcame the difficulties including a small decline in production and escalating costs and maintained strong profitability. The net profit of the Group of the first half of this year reached RMB31.87 billion and once again delivered satisfactory results for the Shareholders.

Since the beginning of the year, the Company has achieved satisfactory development in its overseas business, with overseas oil and gas production increasing significantly. The acquisition of one-third working interest in each of Exploration Area of 1, 2 and 3A in Uganda was also completed on 21 February 2012. The Proposed Acquisition was consistent with the Company’s established value-driven merger and acquisition strategy. The Proposed Acquisition will not only increase the net proved reserves of the Company by around 30% and its net production by around 20%, but also bring to the Company invaluable experience in the area of unconventional oil and gas resources such as oil sands and shale gas, as well as a high-quality management team and employees.

The Proposed Acquisition will enhance the Company’s presence in Canada, Nigeria and the Gulf of Mexico, adds a significant presence in the U.K. North Sea and diversifies the Company’s growth platform. On 8 December 2012, the Proposed Acquisition was approved by Canada’s Minister of Industry under the Investment Canada Act. In connection with the Proposed Acquisition and also to demonstrate its commitment to Canada and the Canadian oil and gas industry, the Company has agreed to carry out a number of commitments, including to establish Calgary as the head office of its North and Central American operations, responsible for approximately US$8 billion of additional assets; retain Nexen’s current management team and employees; invest significant capital as long-term commitment to the development of oil and gas resources in Canada and maintain and enhance community and social commitments. The Company will also list its Shares on the TSX subject to regulatory approvals.

Upon the closing of the Proposed Acquisition, the Company will become a truly global oil and gas exploration and production company with a balanced resources portfolio and important presences in the world’s major oil and gas production areas. At the same time, the Group will be able to acquire the world-class management team and employees from Nexen and establish a leading international development platform. The Directors are confident that the Proposed Acquisition will benefit the Group's long term sustainable growth and create long term value for the Shareholders.

IMPLICATIONS OF THE PROPOSED ACQUISITION UNDER THE LISTING RULES

As one of the applicable percentage ratios calculated under Chapter 14 of the Listing Rules in respect of the Proposed Acquisition exceeds 25% but is less than 100%, the Proposed Acquisition will constitute a major transaction of the Company for the purposes of, and is subject to the notification, publication and shareholders' approval requirements under the Listing Rules.

As no Shareholder of the Company is required to abstain from voting if the Company were to convene a general meeting for approving the Proposed Acquisition, and as the Company has obtained a written approval of the Proposed Acquisition from the Controlling Shareholder, which directly held approximately 64.45% of the issued and outstanding shares of the Company as at the date of the Announcement, pursuant to Rule 14.44 of the Listing Rules, the Company is not required to convene a general meeting for approving the Proposed Acquisition.

WAIVERS FROM STRICT COMPLIANCE WITH THE LISTING RULES

Waiver from the Requirement to Prepare an Accountants' Report on Nexen

Pursuant to Rule 14.67(6)(a)(i) of the Listing Rules, the Company is required to include in this circular an accountants' report on Nexen prepared in accordance with Chapter 4 of the Listing Rules. The accountants' report for the purpose of the Proposed Acquisition is supposed to include the financial information of Nexen for each of the three financial years ended 31 December 2011 and interim accounts for a period ended six months or less from the date of this circular prepared using accounting policies which should be materially consistent with the Company.

Nexen is listed on the TSX and the NYSE. The consolidated financial statements of Nexen for each of the two financial years ended 31 December 2010 were prepared in accordance with Canadian GAAP and have been made publicly available. These financial statements have been audited by Nexen's auditor, Deloitte Canada in accordance with Canadian GAAS and the standards of the Public Company Accounting Oversight Board (United States).

Deloitte Canada is a member of the Canadian Institute of Chartered Accountants and a registered firm with the Canadian Public Accountability Board.

As a company listed on the TSX, Nexen is also required to file quarterly condensed financial statements in accordance with standards established by the CICA for a review of interim financial statements by an entity's auditor.

In 2010, the Handbook of the CICA was revised to incorporate IFRS and require Canadian publicly accountable enterprises to apply such accounting standards effective for financial periods beginning on or after 1 January 2011. Nexen consequently prepared its financial statements for the financial year ended 31 December 2011 in accordance with IFRS, together with a restatement of the financial statements for the financial year ended 31 December 2010 in accordance with IFRS.

Complying with the strict requirements of Rule 14.67(6)(a)(i) of the Listing Rules in having to produce an accountants' report on Nexen in this circular would create practical difficulties, and require Nexen to undertake a considerable amount of work, which would have significant timing, resource and cost implications for the parties involved.

In replacement of an accountants' report on Nexen, the following disclosure has been included in this circular:

(a) the audited financial information for the year ended 31 December 2010 (with2009 comparative financial statements) prepared under Canadian GAAP (the "Nexen 2010 Canadian GAAP Accounts") extracted from the 2010 annual report of Nexen as set out in the section entitled "Appendix II – Financial Information of Nexen Group – Published Financial Information of Nexen Group for Each of the Three Years Ended 31 December 2009, 2010 and 2011 and Six Months Ended 30 June 2012";

(b) the audited financial information for the year ended 31 December 2011 (with 2010 comparative financial statements) (the "Nexen 2011 IFRS Accounts") and the unaudited (but reviewed) financial information for the six months ended 30 June 2012 prepared under IFRS extracted from the 2011 annual report and the second quarter 2012 report of Nexen, respectively, as set out in the section entitled "Appendix II – Financial Information of Nexen Group – Published Financial Information of Nexen Group for Each of the Three Years Ended 31 December 2009, 2010 and 2011 and Six Months Ended 30 June 2012";

(c)a summary of the material differences between the accounting policies adopted by Nexen (Canadian GAAP or IFRS) and the accounting policies adopted by the Company (IFRS and HKFRS), including a line-by-line reconciliation of the consolidated statements of income and consolidated balance sheets, addressing the material differences, other than presentational differences, which would have a significant effect on Nexen's financial statements in (a) and (b) above had they been prepared in accordance with the accounting policies presently adopted by the Company and reported on by Deloitte Hong Kong in accordance with Hong Kong Standard of Assurance Engagements 3000, as set out in the section entitled "Appendix II – Financial Information of Nexen Group – Differences between Accounting Policies Adopted by the Company (IFRS and HKFRS) and Nexen (Canadian GAAP or IFRS)"; and

(d) supplemental financial information of Nexen Group for the three years ended 31 December 2011 and six months ended 30 June 2012, which is required for an accountants' report under the Listing Rules but not disclosed in the published accounts of Nexen excluding the information required under Rule 4.08(3) of the Listing Rules, as set out in the section entitled "Appendix II – Financial Information of Nexen Group – Supplemental Financial Information of Nexen Group".

The Directors consider that the published financial disclosure concerning Nexen reproduced in this circular, when taken together with the abovementioned additional financial disclosure, will afford the Shareholders with all material information necessary to assess the financial performance of Nexen throughout the period presented, such information being broadly commensurate in all material respects to the disclosure that would otherwise have been provided if an accountants' report on Nexen had been produced under Rule 14.67(6)(a)(i). As such, the Company has applied to the Hong Kong Stock Exchange and was granted a waiver from strict compliance with Rule 14.67(6)(a)(i) of the Listing Rules such that the Company is not required to include an accountants' report on Nexen in this circular.

Waivers from the Requirement to Prepare a Competent Person's Report and a Valuation Report on the Petroleum Assets of Nexen

Pursuant to Rule 18.09(2) of the Listing Rules, the circular is required to include a Competent Person's Report on the petroleum assets of Nexen.

As a company listed on the TSX and the NYSE, Nexen has disclosed its reserves information in accordance with NI 51-101 in its annual information forms and annual reports. Nexen also voluntarily reports on reserves under the requirements of the SEC as supplementary information in order to provide direct comparability to the reserves statements of its U.S. peer group and improve access to U.S. capital markets.

Disclosures under NI 51-101 are based upon reserve and resource estimates prepared in accordance with the standards of the COGEH. COGEH is generally based upon the PRMS definition and classification framework system. The standards are interpreted and applied similarly by reserves evaluators. Accordingly, there are generally no material differences between reserve or resource estimates prepared under PRMS and estimates prepared under NI 51-101 (COGEH) (under an equivalent price and cost assumption). In addition, the modifications to the PRMS under Chapter 18 of the Listing Rules and disclosure requirements are materially consistent with the NI 51-101 disclosure requirements.

Nexen has received an exemption from the NI 51-101 requirements to have its reserves estimates independently assessed. The estimates of reserves and future net revenue disclosed by Nexen were based on its internal evaluations. Nexen has put in place an internal evaluation system to ensure that the reliability of the internally generated estimates of reserves and future net revenue is commensurate with that generated by an independent qualified reserves evaluator. The IQRE of Nexen is responsible for the reserves data and related disclosures and assessing whether the reserves estimates and related disclosures have been prepared in accordance with applicable regulatory requirements, Canadian and SEC reserves regulations and related reporting requirements. The IQRE is a professional engineer and meets all professional and statutory requirements in regards to experience, education and professional membership associated with the role. With over 30 years of experience, the

IQRE has an in-depth knowledge of reserves estimation techniques and professional guidelines. As set out in Appendix V to the circular, the IQRE has the relevant professional qualifications and experience to act as a Competent Person under Chapter 18 of the Listing Rules.

Nexen has adopted a corporate policy that prescribes the procedures and standards to be followed in the evaluation of its reserves. This policy is reviewed and amended annually as required to conform to changes in law or industry accepted evaluation practices. Due to the extent and expertise of the internal reserves evaluation resources, the staff's familiarity with the properties of Nexen, and the controls applied to the evaluation process, the reliability of the internally generated estimates of reserves and future net revenue are not materially less than would be generated by an independent qualified reserves evaluator.

Notwithstanding the above mentioned internal evaluation procedure and the exemption from the NI 51-101 requirements to have its reserves estimates independently assessed, the policy of the Nexen is to have at least 80% of its NI 51-101 reserves estimates either evaluated or audited annually by the Independent Reserves Evaluators using applicable NI 51-101 requirements.

Given that reserves estimates are based on a large number of assumptions, interpretations and judgments, differences frequently arise between the estimates prepared by different qualified estimators. When the initial estimate of proved reserves on the portfolio of properties differs by greater than 10%, Nexen works with the Independent Reserves Evaluators to reconcile the difference to within 10%. Estimates pertaining to individual properties within the portfolio may differ by more than 10%, either positively or negatively. Nexen does not attempt to resolve each property to within 10% as it would be time and cost prohibitive given the number of wells in which Nexen has an interest. Nexen follows a similar process in connection with its probable reserves estimates whereby Nexen reconciles any differences on a proved plus probable basis to be within 10%.

The estimates of the Independent Reserves Evaluators are prepared using standard geological and engineering methods generally accepted by the petroleum industry and the reserves principles, definitions and standards required by NI 51-101 and the COGEH. Generally recognized methods for estimating reserves include volumetric calculations, material balance techniques, production and pressure decline curve analysis, analogy with similar reservoirs and reservoir simulation. The method or combination of methods used is based on the professional judgment and experience of the Independent Reserves Evaluators. In preparing their estimates, the Independent Reserves Evaluators obtain information from Nexen with respect to property interests, production from such properties, current costs of operations, expected future development and abandonment costs, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data. They may rely on the information without independent verification. However, if in the course of their evaluation they question the validity or sufficiency of any information, Nexen requests that they not rely on such information until they satisfactorily resolve their questions or independently verify such information.

The Independent Reserves Evaluators do not undertake site visits. Site visits are part of the regular job duties for many of Nexen's qualified reserves evaluators. However, site visits by the Independent Reserves Evaluators are not considered necessary or appropriate for the purpose of evaluating or auditing Nexen's properties due to the following reasons:

(i) unlike hard rock mining operations, oil and gas reserves are not generally accessible for physical inspection;

(ii) Nexen's reserves are located in remote locations in four continents and site visits are prohibitively time consuming and expensive; and

(iii) reserve evaluations are based on electronic data and reports and site visits do not provide any information that would improve the quality of the reserve estimate.

The estimates of the reserves as disclosed in the 2011 AIF have been prepared by Nexen's IQRE with regard to the opinions of the Independent Reserves Evaluators. They have been substantiated by evidence that is supported by analysis and takes into account information supplied to the Independent Reserves Evaluators. In aggregate, the Independent Reserves Evaluators evaluated or audited 96% of the proved and 98% of the proved plus probable reserves of Nexen as of 31 December 2011 as follows:

(i) Nexen engaged D&M to evaluate 100% of its proved and proved plus probable reserves in the UK North Sea, Nigeria, and Canadian shale gas properties. D&M provided an opinion on 26 January 2012, as set out in Appendix IV of this circular, that the proved and proved plus probable reserves for the reviewed properties are reasonable because, in aggregate, they are within 10% of their estimates;

(ii) Nexen engaged McDaniel to evaluate approximately 100% of Nexen's proved and proved plus probable reserves for its in situ oil sands properties. McDaniel provided an opinion on 26 January 2012, as set out in Appendix IV of this circular, that the proved and proved plus probable reserves for the reviewed properties are reasonable because, in aggregate, they are within 10% of their estimates;

(iii) Nexen engaged McDaniel to audit 100% of its proved and proved plus probable reserves for its Syncrude interest. McDaniel provided an opinion on 26 January 2012, as set out in Appendix IV of this circular, that the proved and proved plus probable reserves estimates for the Syncrude property are reasonable because they expect it would be within 10% of their own estimate were they to perform their own detailed evaluation of the property; and

(iv) Nexen engaged Ryder Scott to evaluate 94% of its proved and 97% of its proved plus probable US Gulf of Mexico properties. Ryder Scott provided an opinion on 26 January 2012, as set out in Appendix IV of this circular, that the proved and proved plus probable reserves for the reviewed properties are reasonable because, in aggregate, they are within 10% of their estimates.

Against this background, the Company has applied to the Hong Kong Stock Exchange for a waiver from strict compliance with Rule 18.09(2) of the Listing Rules in respect of preparation of a Competent Person's Report on the petroleum assets of Nexen on the following grounds:

(i) the petroleum assets of Nexen are extensive and are located in various countries around the world. The preparation of a Competent Person's Report for such assets would involve an extraordinary of time and costs, and would be unduly burdensome. Nexen estimates that the preparation of a Competent Person's Report in respect of its reserves and resource estimates as of December 31, 2012 would take approximately 6 months and cost approximately US$2 million;

(ii) Nexen has reported reserves information as of 31 December 2011 in accordance with NI 51-101, which is in broad agreement with PRMS. The estimates of reserves and future net revenue as of 31 December 2011 were prepared in accordance with its strict internal evaluation procedures. Further, in aggregate the Independent Reserves Evaluators evaluated or audited 96% of the proved and 98% of the proved plus probable reserves of Nexen as of 31 December 2011. All these Independent Reserves Evaluators are firms with international names and reputation and as set out in Appendix V to this circular, the primary technical persons of these firms responsible for overseeing the estimate of reserves have the relevant professional qualifications and experience to act as Competent Persons under Chapter 18 of the Listing Rules; and

(iii) as the Shareholders would not need to vote on the Proposed Acquisition and there is sufficient public information in respect of the reserves of the Nexen, the benefit of disclosing the Competent Person's Report in the circular is disproportionate with the costs, time and efforts the Company would need to spend on the preparation of such reports.

In replacement of a Competent Person's Report, the following disclosure has been included in this circular:

(i) the 2011 AIF as set out in Appendix IV to this circular;

(ii) the opinion letters of the Independent Reserves Evaluators as set out in Appendix IV to this circular;

(iii) the qualifications and experience of the IQRE and the primary technical persons of D&M, McDaniel and Ryder Scott responsible for overseeing the estimate of reserves of Nexen as set out in Appendix V to this circular;

(iv) details of information provided to the Independent Reserve Evaluators as set out in this section; and

(v) long term prospects of Nexen as set out in the section entitled "Letter from the Board – Information of Nexen and Its Petroleum Assets – Long Term Prospects of Nexen".

The Company believes that the above disclosure is comparable to the disclosure in a Competent Person's Report as required under Rule 18.09(2) of the Listing Rules except for the disclosure of gross production profiles of the reserves of Nexen and sensitivity analyses for oil and gas prices.

Gross production profiles of the reserves of Nexen are not disclosed in this circular as it is not the common practise for a large oil and gas company like Nexen to disclose such gross production data. Nexen is a large and diversified company with widely varying ownership interests in both operated and non-operated fields. Providing gross production profiles (100% of field production profiles) would introduce large production numbers that cannot be aggregated towards meaningful company data.

Further, this circular does not contain sensitivity analyses for oil and gas prices. Nexen provides NI 51-101 reserves data, which is based upon forecast assumptions. Nexen also provides SEC reserves information based upon SEC existing (constant) assumptions. Both of these analyses are vetted through internal due-diligence, including the effects that pricing may have on project commitment and timing. With a large and diversified portfolio, running meaningful sensitivities involve not only differences in price assumptions but also the corresponding changes to the business decisions and development commitment assumptions involved under each price scenario. The time and resources required to perform an accurate sensitivity analysis are prohibitively high. In addition, generally a sensitivity analysis is more suitable for a junior issuer. It is less relevant for a company with a large and diverse asset base such as Nexen because it is less sensitive to commodity price fluctuations than a junior issuer with few assets. For these reasons, the Company considers that a sensitivity analysis is inappropriate and unnecessary for the Shareholders to assess the Proposed Acquisition.

According to the Canadian Securities Law, in the event that there is any material change in the reserve information in the 2011 AIF, Nexen would need to issue and file a news release and file a material change report discussing its reasonable expectation as to how the material change has affected its reserve data and/or information disclosed in public reports. Nexen has confirmed that it has not filed, nor anticipates filing, a material change report relating to the reserves information in the 2011 AIF prior to the Latest Practicable Date.

Nexen monitors actual production results at least quarterly to assess whether they are consistent with the forecasts used for the most recent reserves estimates. Nexen also reviews reserves changes generated by exploration, development, acquisition and divestiture activities on an ongoing basis as well as changes to price and cost assumptions and the legal and regulatory environment applicable to its operations. Quarterly, Nexen management reviews preliminary estimates of potential reserves changes that may occur by year-end with regard to the above factors stated. Nexen has further confirmed that in its most recent reserves review completed mid-November 2012, with regard to the above factors stated, the expected changes are not material to its proved and proved plus probable reserves since 31 December 2011.

Taking into account of the above, the Company confirms that, as of the Latest Practicable Date, there has been no material changes to the proved and probable reserves of Nexen as disclosed in the 2011 AIF since 31 December 2011.

Based on the above, the Hong Kong Stock Exchange has granted a wavier from strict compliance with Rule 18.09(2) of the Listing Rules such that the Company is not required to include in the circular a Competent Person's Report on the petroleum assets of Nexen.

Pursuant to Listing Rule 18.09(3) of the Listing Rules, the circular is required to include a Valuation Report on the petroleum assets of Nexen.

For the Proposed Acquisition, the target of the acquisition is the shares of Nexen, a publicly listed company, and not specific assets, nor a privately owned asset with no readily available reference point for valuation. Nexen's shares are traded on the TSX and the NYSE which are well-developed and recognized stock exchanges with substantial market capitalization and liquidity. The Company believes that the share trading prices and market capitalization of Nexen serves as a reasonable reference in assessing Nexen's fair market value. The Company used multiple methodologies in determining the Consideration and offer price for the Proposed Acquisition, with a strong emphasis on Nexen's share price, liquidity and trading movement as well market-based analysis. The Company has performed various financial analysis, including, but not limited to: (a) market-based analysis; (b) reserves and resources based analysis; and (c) fundamental valuation analyses (e.g. discounted cash flow, metrics of comparable companies, precedent transactions and premiums paid) in order to determine an appropriate offer price. As the Consideration for the Proposed Acquisition was primarily based on the above approaches rather than an asset valuation approach, it would be unduly burdensome and irrelevant for the Company to prepare a separate Valuation Report on the petroleum assets of Nexen.

Therefore, the Company has applied to the Hong Kong Stock Exchange and the Hong Kong Stock Exchange has granted a waiver from strict compliance with Rule 18.09(3) of the Listing Rules such that the Company is not required to include a Valuation Report on the petroleum assets of Nexen.

## RECOMMENDATION OF THE BOARD

The Directors are of the opinion that the terms of the Arrangement Agreement and the transactions contemplated thereunder are fair and reasonable and in the interests of the Company and its Shareholders as a whole.

Shareholders and potential investors should note that the Proposed Acquisition is subject to various Conditions which may or may not be fulfilled. There is therefore no assurance that the Proposed Acquisition will proceed and, if it proceeds, on what terms it may proceed. Shareholders and potential investors are reminded to exercise caution when dealing in the Shares of the Company.

Yours faithfully,
For and on behalf of the Board
CNOOC Limited
Wang Yilin
Chairman of the Board of Directors

## 1. FINANCIAL INFORMATION OF THE GROUP FOR EACH OF THE THREE YEARS ENDED 31 DECEMBER 2009, 2010 AND 2011 AND THE SIX MONTHS ENDED 30 JUNE 2012

Financial information of the Group for each of the three years ended 31 December 2009, 2010 and 2011 and for the six months ended 30 June 2012 is disclosed in the following documents which have been published on the websites of the Hong Kong Stock Exchange (http://www.hkexnews.hk) and the Company (http://www.cnoocltd.com):

Interim report of the Company for the six months ended 30 June 2012 published on 31 August 2012 (Pages 8 to 36);

Annual report of the Company for the year ended 31 December 2011 published on 12 April 2012 (pages 61 to 116);

Annual report of the Company for the year ended 31 December 2010 published on 7 April 2011 (pages 57 to 114); and

Annual report of the Company for the year ended 31 December 2009 published on 9 April 2010 (pages 49 to 104).

## 2. INDEBTEDNESS STATEMENT

As at the close of business on 31 October 2012, being the latest practicable date for the purpose of this indebtedness statement prior to the printing of this circular, the Enlarged Group had the following outstanding borrowings:

| | Secured RMB million | Guaranteed RMB million | Unsecured RMB million | Total RMB million |
|---|---|---|---|---|
| Bank loans | 8,631 | 2,669 | 19,217 | 30,517 |
| Long-term notes | – | 28,048 | 24,761 | 52,809 |
| Subordinated debentures | – | – | 2,900 | 2,900 |
| | 8,631 | 30,717 | 46,878 | 86,226 |

The general bank loan of US$1,370 million (equivalent to RMB8,631 million) was secured by time deposits placed by CNOOC China Limited, a wholly-owned subsidiary of the Company.

The specific borrowing of US$424 million (equivalent to RMB2,669 million) represented the Enlarged Group’s share of utilised bank loans in Tangguh Liquified Natural Gas Project (the “Tangguh LNG Project”). The Company delivered a guarantee in favour of Mizuho Corporate Bank, Ltd., which acts as the facility agent for and on behalf of various international commercial banks under a commercial loan agreement in connection with the Tangguh LNG Project in Indonesia. The Company guarantees the payment obligations of the trustee borrower under the subject loan agreement and is subject to a maximum cap of

approximately US$164.89 million. Together with the loan agreement dated 31 July 2006 with a maximum cap of approximately US$487.86 million, the total maximum guarantee cap is US$652.75 million.

The long-term notes amounting to RMB28,048 million are unconditionally and irrevocably guaranteed by the Company.

Banking facilities

As at 31 October 2012, the banking facilities amounting to RMB116,543 million were granted to the Enlarged Group, of which RMB17,618 million were utilised as follows:

(i) RMB5,390 million of these facilities were utilised to support letter of credit;

(ii) RMB2,148 million of these facilities were utilised to support bank guarantee; and

(iii)RMB10,080 million of these facilities were utilised to withdraw bank borrowings.

Financial lease

As at 31 October 2012, the Enlarged Group had an outstanding finance lease of approximately RMB497 million of which RMB106 million is repayable within the next five years.

Guarantees

On 6 August 2012, the Enlarged Group guaranteed a drilling rig sublease contract for approximately 180 days with potential exposure of C$90 million (equivalent to RMB567 million). As at 31 October 2012, this contract had approximately 135 days outstanding and C$67 million potential exposure amount remaining (equivalent to RMB422 million).

Contingencies

(a)On 8 January 2006, a subsidiary of the Company signed a definitive agreement with South Atlantic Petroleum Limited ("SAPETRO") to acquire a 45% working interest in the Offshore Oil Mining Lease 130 ("OML130") in Nigeria (the "OML130 Transaction") and the OML130 Transaction was completed on 20 April 2006.

In 2007, a local tax office in Nigeria (the "Nigerian Local Tax Office") conducted a tax audit on SAPETRO. According to the preliminary tax audit results, the Nigerian Local Tax Office has raised a disagreement with the tax filings made for the OML130 Transaction.

The tax audit assessment made by the Nigerian Local Tax Office has been contested by the Company in accordance with Nigerian laws. The Company then filed a suit in the Nigerian Federal High Court. In March 2011, the Nigeria Federal High Court delivered a binding judgement in favour of the Company, agreeing that the Company is not subject to Value Added Tax for the OML130 Transaction. The judgement was appealed

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by counterparties. After seeking legal advice, the Company's management believes that the Company has reasonable grounds in defending for such an appeal. Consequently, no provision has been made for any expenses which might arise as a result of the dispute.

(b)On 26 October 2011, CNOOC Exploration & Production Nigeria Limited ("CNOOC Nigeria"), a subsidiary of the Company, received notice of assessment from Federal Inland Revenue Service of Nigeria ("FIRS"), confirming that the effective Petroleum Profit Tax ("PPT") and related tax in the year of 2010 for the Company's investment in the OML130 project, shall be calculated and payable on the basis of the PPT Tax Return prepared by Nigerian National Petroleum Corporation. CNOOC Nigeria contested the notice of assessment. On 13 January 2012, CNOOC Nigeria, together with SAPETRO (collectively referred to as the "PSC Partners"), filed an appeal in relation thereto to the local Tax Appeal Tribunal ("TAT").

CNOOC Nigeria received a notice of assessment issued by FIRS on 13 June 2012, stating that investment tax allowance ("ITA"), instead of investment tax credit ("ITC"), should be applied for the PPT calculation of the Company's investment in the OML130 project. In July 2012, PSC Partners filed an appeal in relation thereto to the local TAT. However, whether TAT has jurisdiction over this dispute is uncertain under the Nigerian law, in order to protect the right of action, the PSC Partners filed an application to the Nigeria Federal High Court ("FHC") on 13 September 2012, seeking the permission to file a lawsuit over the application of ITA/ITC dispute at FHC; and the appeal over ITA/ITC dispute at TAT was withdrawn on 9 November 2012.

No verdict has been issued to date, and the results of the appeals are still uncertain.

(c)The Company has extended interest-free intercompany loans to CNOOC International Limited, a wholly-owned subsidiary, to provide onward funding to its subsidiaries domiciled outside the PRC. Upon receipt of the Chinese resident enterprise approval, the Company may be liable to pay taxes on the deemed interest income for the intercompany loan to CNOOC International Limited starting from 1 January 2008. The Company is currently applying to, and awaiting confirmation from its in-charge tax authority for an exemption on this possible deemed interest income. In July 2011, the Company completed the transfer of the interest-free intercompany loans to the capital investment in CNOOC International Limited, in order to reduce the future tax exposure arising from any deemed interest income for the intercompany loans.

(d)Two oil spill accidents occurred on 4 June and 17 June 2011 respectively at Platforms B and C of Penglai 19-3 oilfield, which is being operated under a production sharing contract ("PSC") among CNOOC China Limited, the subsidiary of the Company, and two subsidiaries of ConocoPhillips ("ConocoPhillips"), the US based oil company, among which ConocoPhillips China Inc. ("COPC") is the operator and responsible for the daily operations of the oilfield.

On 21 June 2012, the State Oceanic Administration of the PRC announced the Accident Investigation and Settlement Report by a Joint Investigation Team on the Penglai 19-3 Oilfield Oil Spill Accidents, pointing out that "the Joint Investigation Team has concluded that COPC violated the oilfield Overall Development Program, had defects

in its operation procedures and management, and failed to take necessary precautionary measures against foreseen risks, all of which eventually resulted in the oil spills. The Penglai 19-3 Oilfield Oil Spill Accidents were accidents involving liabilities, causing significant marine pollution by oil spill. Pursuant to the PSC, COPC (the operator of the oilfield) shall bear full responsibility for the oil spill accidents".

The Company is of the view that the Company's obligations, if any, arising from the above mentioned accidents shall be determined in accordance with relevant laws and regulations, the PSC and related agreements, among others. Based on evaluations performed as of the date of this indebtedness statement, the Company believes that it is not possible to determine provisions, if any, for the above mentioned accidents. The financial impact of such oil spill accidents on the Company is still uncertain, and the Company has not made any provision for the accidents in the financial statements.

(e)The Company has been served with (via its designated agent for service of process in the United States) process on 11 October 2012 for a purported class action complaint filed by Sam Siany, individually and on behalf of all others similarly situated in the United States District Court for the Southern District of New York (the "Complaint"). The Complaint is lodged against the Company and certain of its directors and/or officers, which alleges that during the period between 27 January 2011 and 16 September 2011, the Company made materially false and misleading statements regarding its business and financial results and the oil spill accidents occurred at the Penglai 19-3 oilfield. No verdict has been issued to the date. The Company believes the allegations and the claims in the Complaint are without merit and intends to defend itself vigorously against such claims.

Liquidity

The Enlarged Group's debt levels are directly related to its operating cash flows, capital expenditures and acquisition and divestiture activity. Management generally relies on operating cash flows to fund capital requirements and maintain liquidity. Given the long development cycle of our projects, and fluctuations in commodity prices and exchange rates, it is not unusual for capital expenditures to exceed operating cash flows in any given period. Management covers these differences by drawing on existing liquidity or obtaining additional banking facilities.

As at 31 October 2012, the Enlarged Group had outstanding debt of approximately RMB86,226 million of which RMB31,627 million is repayable within the next five years. The Enlarged Group had liquidity of approximately RMB137,409 million, primarily comprised of cash and undrawn term credit facilities. Management expects to be able to fund all planned capital expenditures, repay our debt when it comes due, and meet all other obligations that arise from the Enlarged Group's oil and gas operations.

Currency risk

Management of the Group has assessed the Group's exposure to foreign currency risk by using a sensitivity analysis on the change in foreign exchange rate of US dollars, to which the Group is mainly exposed to.

Nexen Group manages its exposure to fluctuations in exchange rates by matching its expected net cash flows and borrowings in the same currency. Cash flows generated by its foreign operations and borrowings on its US dollar debt facilities are generally used to fund US dollar capital expenditures and debt repayments. Nexen Group maintains revolving Canadian and US dollar borrowing facilities that can be drawn upon or repaid depending on expected net cash flows. Nexen Group designates most of its US dollar borrowings as a hedge against its US dollar net investment in its foreign operations.

Save as aforesaid or as otherwise mentioned herein, and apart from intra-group liabilities, none of the companies in the Enlarged Group had, at the close of business on 31 October 2012, any outstanding loan capital issued and outstanding or agreed to be issued, bank overdrafts, charges or debentures, mortgages, loans or other similar indebtedness or any finance lease commitments, hire purchase commitments, liabilities under acceptances, acceptance credits or any guarantees or other material contingent liabilities.

The Directors have confirmed that there have been no material changes in the indebtedness and contingent liabilities of the Enlarged Group since 31 October 2012.

For the purpose of the above indebtedness statement, foreign currency amounts have been translated into RMB at the exchange rates of US$1.00 to RMB6.3002 and C$1.00 to RMB6.3037 prevailing at the close of business on 31 October 2012.

## 3. WORKING CAPITAL

The Directors are of the opinion that, upon the completion of the proposed acquisition of all the common shares and preferred shares of Nexen, taking into account the present financial resources available to the Enlarged Group, including internally generated funds, access to financing and available banking facilities, and in the absence of unforeseeable circumstances, the Enlarged Group will have sufficient working capital for its present requirements for at least the next 12 months from the date of this circular.

## 4. NO MATERIAL ADVERSE CHANGE

As at the Latest Practicable Date, the Directors were not aware of any material adverse change in the financial or trading position or prospect of the Group since 31 December 2011, the date to which the latest published audited financial statements of the Group were made up.

I.PUBLISHED FINANCIAL INFORMATION OF NEXEN GROUP FOR EACH OF THE THREE YEARS ENDED 31 DECEMBER 2009, 2010 AND 2011 AND THE SIX MONTHS ENDED 30 JUNE 2012

(1)The following is an extract of the unaudited condensed interim financial statements of Nexen Group for the six months ended 30 June 2012, which were prepared in accordance with IFRS. These condensed interim financial statements were presented in C$ million dollars except for otherwise stated.

Nexen's interim financial statements are available free of charge, in read only, printable format on Nexen's website.

Unaudited Condensed Consolidated Statement of Income
For the Three and Six Months Ended June 30

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| (Cdn$ millions, except per-share amounts) | | | | |
| Revenues and Other Income | | | | |
| Net Sales | 1,659 | 1,507 | 3,355 | 3,105 |
| Marketing and Other Income (Note 8) | 128 | 95 | 158 | 141 |
| | 1,787 | 1,602 | 3,513 | 3,246 |
| Expenses | | | | |
| Operating | 376 | 341 | 715 | 704 |
| Depreciation, Depletion and Amortization | 488 | 335 | 885 | 705 |
| Transportation and Other | 105 | 112 | 225 | 179 |
| General and Administrative | 115 | 76 | 241 | 181 |
| Exploration | 155 | 93 | 215 | 219 |
| Finance (Note 5) | 81 | 60 | 145 | 134 |
| Loss on Debt Redemption and Repurchase | – | 1 | – | 91 |
| Gain from Dispositions (Note 10) | (45) | – | (45) | – |
| | 1,275 | 1,018 | 2,381 | 2,213 |
| Income from Continuing Operations before Provision for Income Taxes | 512 | 584 | 1,132 | 1,033 |

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| (Cdn$ millions, except per-share amounts) | | | | |
| Provision for (Recovery of) Income Taxes | | | | |
| Current | 396 | 384 | 876 | 808 |
| Deferred | 7 | (52) | (24) | 73 |
| | 403 | 332 | 852 | 881 |
| Net Income from Continuing Operations | 109 | 252 | 280 | 152 |
| Net Income from Discontinued Operations, Net of Tax | – | – | – | 302 |
| Net Income Attributable to Nexen Inc. Shareholders | 109 | 252 | 280 | 454 |
| | | | | |
| Earnings Per Common Share from Continuing Operations ($/share) (Note 6) | | | | |
| Basic | 0.20 | 0.48 | 0.52 | 0.29 |
| Diluted | 0.19 | 0.45 | 0.52 | 0.27 |
| Earnings Per Common Share ($/share) (Note 6) | | | | |
| Basic | 0.20 | 0.48 | 0.52 | 0.86 |
| Diluted | 0.19 | 0.45 | 0.52 | 0.84 |

See accompanying notes to the Unaudited Condensed Consolidated Financial Statements.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

Unaudited Condensed Consolidated Balance Sheet

| (Cdn$ millions) | June 30 2012 | December 31 2011 |
|---|---|---|
| Assets | | |
| Current Assets | | |
| Cash and Cash Equivalents | 1,255 | 845 |
| Restricted Cash | 102 | 45 |
| Accounts Receivable | 1,685 | 2,247 |
| Derivative Contracts | 155 | 119 |
| Inventories and Supplies | 283 | 320 |
| Other | 137 | 115 |
| Total Current Assets | 3,617 | 3,691 |
| Non-Current Assets | | |
| Property, Plant and Equipment (Note 3) | 16,030 | 15,571 |
| Goodwill | 292 | 291 |
| Deferred Income Tax Assets | 442 | 338 |
| Derivative Contracts | 5 | 25 |
| Other Long-Term Assets | 112 | 152 |
| Total Assets | 20,498 | 20,068 |
| Liabilities | | |
| Current Liabilities | | |
| Accounts Payable and Accrued Liabilities | 2,285 | 2,867 |
| Income Taxes Payable | 849 | 458 |
| Derivative Contracts | 105 | 103 |
| Total Current Liabilities | 3,239 | 3,428 |
| Non-Current Liabilities | | |
| Long-Term Debt | 4,391 | 4,383 |
| Deferred Income Tax Liabilities | 1,561 | 1,488 |
| Asset Retirement Obligations | 2,020 | 2,010 |
| Derivative Contracts | 5 | 24 |
| Other Long-Term Liabilities | 443 | 362 |
| Equity (Note 6) | | |
| Share Capital | | |
| Common Shares | 1,183 | 1,157 |
| Preferred Shares | 195 | – |
| Retained Earnings | 7,435 | 7,211 |
| Cumulative Translation Adjustment | 26 | 5 |
| Total Equity | 8,839 | 8,373 |
| Total Liabilities and Equity | 20,498 | 20,068 |

See accompanying notes to Unaudited Condensed Consolidated Financial Statements.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

Unaudited Condensed Consolidated Statement of Cash Flows
For the Three and Six Months Ended June 30

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| (Cdn$ millions) | | | | |
| Operating Activities | | | | |
| Net Income from Continuing Operations | 109 | 252 | 280 | 152 |
| Net Income from Discontinued Operations | – | – | – | 302 |
| Charges and Credits to Income not Involving Cash (Note 9) | 455 | 261 | 906 | 610 |
| Exploration Expense | 155 | 93 | 215 | 219 |
| Changes in Non-Cash Working Capital (Note 9) | 446 | 419 | 300 | 485 |
| Other | (6) | (5) | (34) | (18) |
| | 1,159 | 1,020 | 1,667 | 1,750 |
| Financing Activities | | | | |
| Repayment of Long-Term Debt | – | (525) | – | (871) |
| Issue of Preferred Shares | – | – | 195 | – |
| Dividends Paid on Common Shares | (27) | (26) | (53) | (52) |
| Issue of Common Shares | 8 | 8 | 26 | 31 |
| Other | (4) | (6) | (6) | 1 |
| | (23) | (549) | 162 | (891) |
| Investing Activities | | | | |
| Capital Expenditures | | | | |
| Exploration, Evaluation and Development | (718) | (516) | (1,454) | (992) |
| Corporate and Other | (25) | (20) | (46) | (37) |
| Proceeds from Dispositions (Note 10) | 46 | 12 | 53 | 474 |
| Changes in Restricted Cash | (82) | (2) | (56) | (11) |
| Changes in Non-Cash Working Capital (Note 9) | 23 | 31 | 65 | 115 |
| Other | (4) | (23) | 5 | (75) |
| | (760) | (518) | (1,433) | (526) |
| Effect of Exchange Rate Changes on Cash and Cash Equivalents | 23 | (15) | 14 | (26) |
| Increase (Decrease) in Cash and Cash Equivalents | 399 | (62) | 410 | 307 |
| Cash and Cash Equivalents – Beginning of Period | 856 | 1,374 | 845 | 1,005 |
| | | | | |
| Cash and Cash Equivalents – End of Period[1] | 1,255 | 1,312 | 1,255 | 1,312 |

1 Cash and cash equivalents at June 30, 2012 consists of cash of $319 million and short-term investments of $936 million (June 30, 2011 — cash of $218 million and short-term investments of $1,094 million).

See accompanying notes to the Unaudited Condensed Consolidated Financial Statements.

Unaudited Condensed Consolidated Statement of Changes in Equity
For the Three and Six Months Ended June 30

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| (Cdn$ millions) | | | | |
| Share Capital | | | | |
| Common Shares, Beginning of Period | 1,175 | 1,134 | 1,157 | 1,111 |
| Issue of Common Shares | 8 | 8 | 26 | 31 |
| Common Shares, Balance at End of Period | 1,183 | 1,142 | 1,183 | 1,142 |
| Preferred Shares, Beginning of Period | 195 | – | – | – |
| Issue of Preferred Shares | – | – | 195 | – |
| Preferred Shares, Balance at End of Period | 195 | – | 195 | – |
| Retained Earnings, Beginning of Period | 7,356 | 6,868 | 7,211 | 6,692 |
| Net Income Attributable to Nexen Inc. Shareholders | 109 | 252 | 280 | 454 |
| Dividends on Common and Preferred Shares (Note 6) | (30) | (26) | (56) | (52) |
| Balance at End of Period | 7,435 | 7,094 | 7,435 | 7,094 |
| Cumulative Translation Adjustment, | | | | |
| Beginning of Period | (8) | (48) | 5 | (37) |
| Currency Translation Adjustment | 23 | (7) | 5 | (18) |
| Realized Translation Adjustments1 | 11 | – | 16 | – |
| Balance at End of Period | 26 | (55) | 26 | (55) |

1Net of income tax recovery for the three months ended June 30, 2012 of $5 million (2011 – net of income tax expense of $11 million) and net of income tax recovery for the six months ended June 30, 2012 of $7 million (2011 – net of income tax expense of $20 million).

See accompanying notes to the Unaudited Condensed Consolidated Financial Statements.

Unaudited Condensed Consolidated Statement of Comprehensive Income
For the Three and Six Months Ended June 30

| (Cdn$ millions) | Three Months Ended June 30 2012 | Three Months Ended June 30 2011 | Six Months Ended June 30 2012 | Six Months Ended June 30 2011 |
|---|---|---|---|---|
| Net Income Attributable to Nexen Inc. Shareholders | 109 | 252 | 280 | 454 |
| Other Comprehensive Income (Loss): | | | | |
| Currency Translation Adjustment | | | | |
| Net Translation Gains (Losses) of Foreign Operations | 98 | (35) | 14 | (139) |
| Net Translation Gains (Losses) on US$-Denominated Debt Hedging of Foreign Operations1 | (75) | 28 | (9) | 121 |
| Total Currency Translation Adjustment | 23 | (7) | 5 | (18) |
| Total Comprehensive Income | 132 | 245 | 285 | 436 |

1Net of income tax recovery for the three months ended June 30, 2012 of $10 million (2011 – net of income tax expense of $4 million) and net of income tax recovery for the six months ended June 30, 2012 of $1 million (2011 – net of income tax expense of $17 million).

See accompanying notes to the Unaudited Condensed Consolidated Financial Statements.

Notes to Unaudited Condensed Consolidated Financial Statements
Cdn$ millions, except as noted

## 1. BASIS OF PRESENTATION

Nexen Inc. (Nexen, we or our) is an independent, global energy company with operations in the UK North Sea, US Gulf of Mexico, offshore Nigeria, Canada, Yemen, Colombia and Poland. Nexen is incorporated and domiciled in Canada and our head office is located at 801-7th Avenue SW, Calgary, Alberta, Canada. Nexen's shares are publicly traded on both the Toronto Stock Exchange and the New York Stock Exchange.

These Unaudited Condensed Consolidated Financial Statements for the three and six months ended June 30, 2012 have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB). Specifically, they have been prepared in accordance with International Accounting Standard (IAS) 34 Interim Financial Reporting. The Unaudited Condensed Consolidated Financial Statements do not include all of the information required for annual financial statements and should be read in conjunction with the Audited Consolidated Financial Statements for the year ended December 31, 2011, which have been prepared in accordance with IFRS.

The Unaudited Condensed Consolidated Financial Statements were authorized for issue by Nexen's Board of Directors on July 18, 2012.

## 2. ACCOUNTING POLICIES

The accounting policies we follow are described in Note 2 of the Audited Consolidated Financial Statements for the year ended December 31, 2011. There have been no changes to our accounting policies since December 31, 2011.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

## 3. PROPERTY, PLANT AND EQUIPMENT (PP&E)

Carrying amount of PP&E

| | Exploration and Evaluation | Assets Under Construction | Producing Oil & Gas Properties | Corporate and other | Total |
|---|---|---|---|---|---|
| Cost | | | | | |
| As at December 31, 2011 | 2,206 | 2,347 | 19,832 | 837 | 25,222 |
| Addition | 390 | 335 | 729 | 46 | 1,500 |
| Disposals/Derecognitions | (9) | – | (74) | (15) | (98) |
| Transfers1 | – | (1,862) | 1,862 | – | – |
| Exploration Expense | (215) | – | – | – | (215) |
| Other | (17) | – | 51 | 17 | 51 |
| Effect of Changes in Exchange Rate | 5 | 1 | 40 | 1 | 47 |
| As at June 30, 2012 | 2,360 | 821 | 22,440 | 886 | 26,507 |
| Accumulated Depreciation, Depletion & Amortization (DD&A) | | | | | |
| As at December 31, 2011 | 368 | – | 8,860 | 423 | 9,651 |
| DD&A | 33 | – | 809 | 43 | 885 |
| Disposals/Derecognitions | (8) | – | (74) | (12) | (94) |
| Other | – | – | (8) | 17 | 9 |
| Effect of Changes in Exchange Rate | – | – | 26 | – | 26 |
| As at June 30, 2012 | 393 | – | 9,613 | 471 | 10,477 |
| Net Book Value | | | | | |
| As at December 31, 2011 | 1,838 | 2,347 | 10,972 | 414 | 15,571 |
| As at June 30, 2012 | 1,967 | 821 | 12,827 | 415 | 16,030 |

1Includes PP&E costs related to our Usan development, offshore Nigeria which came on-stream February 2012.

Exploration and evaluation assets mainly comprise of unproved properties and capitalized exploration drilling costs. Assets under construction at June 30, 2012 primarily include our developments in the UK North Sea.

## 4. LONG-TERM DEBT

During the three and six months ended June 30, 2012, we borrowed and repaid nil and $254 million on our term credit facilities, respectively. We recorded $85 million and $10 million, respectively, of unrealized foreign exchange losses on long-term debt in other comprehensive income.

We have undrawn, committed, unsecured term credit facilities of $3.8 billion, of which $700 million is available until 2014 and $3.1 billion is available until 2017. As at June 30, 2012, $232 million of our term credit facilities were utilized to support letters of credit (December 31, 2011 – $367 million).

Nexen has undrawn, uncommitted, unsecured credit facilities of approximately $180 million. We utilized $21 million of these facilities to support outstanding letters of credit at June 30, 2012 (December 31, 2011 – $17 million).

Nexen has uncommitted, unsecured credit facilities of approximately $214 million exclusively to support letters of credit. We utilized $3 million of these facilities to support outstanding letters of credit at June 30, 2012 (December 31, 2011 – $4 million).

## 5. FINANCE EXPENSE

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| Interest on Long-Term Debt | 73 | 74 | 148 | 158 |
| Accretion Expense Related to Asset Retirement Obligations | 13 | 12 | 26 | 23 |
| Other Interest and Fees | 7 | 3 | 12 | 10 |
| Total | 93 | 89 | 186 | 191 |
| Less: Capitalized at 6.7% (2011 – 6.6%) | (12) | (29) | (41) | (57) |
| Total | 81 | 60 | 145 | 134 |

Capitalized interest relates to and is included as part of the cost of our oil and gas properties. The capitalization rates are based on our weighted-average cost of borrowings.

## 6. EQUITY

### (a) Common Shares

Authorized share capital consists of an unlimited number of common shares of no par value. At June 30, 2012, there were 529,335,905 common shares outstanding (December 31, 2011 – 527,892,635 common shares).

### (b) Preferred Shares

Authorized share capital consists of an unlimited number of Class A preferred shares of no par value, issuable in series. At June 30, 2012, there were 8,000,000 Cumulative Redeemable Class A Rate Reset Preferred Shares, Series 2 outstanding (December 31, 2011 – nil).

### (c) Earnings Per Common Share (EPS)

We calculate basic EPS using net income attributable to Nexen Inc. shareholders, adjusted for preferred share dividends and divided by the weighted-average number of common shares outstanding. We calculate diluted EPS in the same manner as basic, except we adjust basic earnings for the potential conversion of the subordinated debentures and potential exercise of outstanding tandem options for shares, if dilutive. We use the weighted-average number of diluted common shares outstanding in the denominator of our diluted EPS calculation.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

| (Cdn$ millions) | Three Months Ended June 30 2012 | 2011 | Six Months Ended June 30 2012 | 2011 |
|---|---|---|---|---|
| Net Income Attributable to Nexen Inc. Shareholders | 109 | 252 | 280 | 454 |
| Preferred Share Dividends | (2) | – | (3) | – |
| Net Income Attributable to Nexen Inc. Shareholders, Basic | 107 | 252 | 277 | 454 |
| Potential Tandem Options Exercises | (7) | (14) | (3) | (9) |
| Potential Conversion of Subordinated Debentures | – | 6 | 13 | 12 |
| Net Income Attributable to Nexen Inc. Shareholders, Diluted | 100 | 244 | 287 | 457 |
| | | | | |
| (millions of shares) | | | | |
| | | | | |
| Weighted Average Number of Common Shares Outstanding, Basic | 529 | 527 | 529 | 527 |
| Common Shares Issuable Pursuant to Tandem Options | – | 2 | – | 2 |
| Common Shares Notionally Purchased from Proceeds of Tandem Options | – | (2) | – | (2) |
| Common Shares Issuable Pursuant to Potential Conversion of Subordinated Debentures | – | 20 | 26 | 19 |
| Weighted Average Number of Common Shares Outstanding, Diluted | 529 | 547 | 555 | 546 |

In calculating the weighted-average number of diluted common shares outstanding and related earnings adjustments for the three and six months ended June 30, 2012, we excluded 14,910,152 and 14,879,437 tandem options, respectively (2011 – 15,068,347 and 15,210,923, respectively) because their exercise price was greater than the average common share market price in the quarter. During the three months ended June 30, 2012, the potential conversion of tandem options was the only dilutive instrument. During the six months ended June 30, 2012, and the three and six months ended June 30, 2011, the potential conversion of tandem options and subordinated debentures were the only dilutive instruments.

(d) Dividends

We paid dividends of $0.05 and $0.10 per common share, for the three and six months ended June 30, 2012 ($0.05 and $0.10 per common share for the respective periods ended June 30, 2011). Dividends paid to holders of common shares have been designated as “eligible dividends” for Canadian tax purposes.

On July 18, 2012, the board of directors declared a quarterly dividend of $0.05 per common share, payable October 1, 2012 to the shareholders of record on September 10, 2012. Also, the board of directors declared a quarterly dividend of $0.3125 per preferred share, payable September 30, 2012 to the shareholders of record on September 10, 2012.

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APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

7. COMMITMENTS, CONTINGENCIES AND GUARANTEES

As described in Note 19 to the 2011 Audited Consolidated Financial Statements, there are a number of lawsuits and claims pending, the ultimate results of which cannot be ascertained at this time. We record costs as they are incurred or become determinable. We believe that payments, if any, related to existing indemnities would not have a material adverse effect on our liquidity, financial condition or results of operations.

We assume various contractual obligations and commitments in the normal course of our operations. During the quarter, we entered into drilling rig commitments in the UK North Sea.

| | 2012 | 2013 | 2014 | 2015 | 2016 | Thereafter |
|---|---|---|---|---|---|---|
| Drilling Rig Commitments | – | 74 | 46 | – | – | – |

The commitments above are in addition to those included in Note 19 to the 2011 Audited Consolidated Financial Statements and Note 7 to the Unaudited Condensed Consolidated Financial Statements for the three months ended March 31, 2012.

8. MARKETING AND OTHER INCOME

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| Marketing Revenue, Net | 110 | 51 | 175 | 102 |
| Foreign Exchange Gains (Losses) | 12 | 6 | (4) | (16) |
| Change in Fair Value of Crude Oil Put Options | 2 | – | (34) | (7) |
| Insurance Proceeds | – | 26 | – | 26 |
| Other | 4 | 12 | 21 | 36 |
| Total | 128 | 95 | 158 | 141 |

9. CASH FLOWS

(a) Charges and credits to income not involving cash

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| Depreciation, Depletion and Amortization | 488 | 335 | 885 | 705 |
| Gain from Dispositions | (45) | – | (45) | – |
| Change in Fair Value of Crude Oil Put Options | (2) | – | 34 | 7 |
| Stock-Based Compensation | (2) | (29) | 24 | (2) |
| Foreign Exchange | (8) | (6) | 8 | 17 |
| Provision for (Recovery of) Deferred Income Taxes | 7 | (52) | (24) | 73 |

| | | | | |
|---|---|---|---|---|
| Loss on Debt Redemption and Repurchase | – | 1 | – | 91 |
| Non-Cash Items Included in Discontinued Operations | – | – | – | (290 ) |
| Other | 17 | 12 | 24 | 9 |
| Total | 455 | 261 | 906 | 610 |

(b) Changes in non-cash working capital

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| Accounts Receivable | 348 | 240 | 513 | (134) |
| Inventories and Supplies | 47 | 163 | 40 | 184 |
| Other Current Assets | (15) | (17) | (17) | (9) |
| Accounts Payable and Accrued Liabilities | (283) | (248) | (546) | 169 |
| Current Income Taxes Payable | 372 | 312 | 375 | 390 |
| Total | 469 | 450 | 365 | 600 |
| Relating to: | | | | |
| Operating Activities | 446 | 419 | 300 | 485 |
| Investing Activities | 23 | 31 | 65 | 115 |
| Total | 469 | 450 | 365 | 600 |

(c) Other cash flow information

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| Interest Paid | 58 | 66 | 148 | 130 |
| Income Taxes Paid | 17 | 69 | 497 | 460 |

## 10. DISPOSITIONS

Asset Dispositions

Canadian Undeveloped Leases

During the quarter, we sold non-core leases in Canada for proceeds of $46 million and recognized a gain of $45 million.

## 11. OPERATING SEGMENTS AND RELATED INFORMATION

Nexen has the following operating segments:

Conventional Oil and Gas: We explore for, develop and produce crude oil and natural gas from conventional sources around the world. Our operations are focused in the UK North Sea, North America (Canada and US) and other countries (offshore Nigeria, Colombia, Yemen and Poland).

Oil Sands: We develop and produce synthetic crude oil from the Athabasca oil sands in northern Alberta. We produce bitumen using in situ and mining technologies and upgrade it into synthetic crude oil before ultimate sale. Our in situ activities are comprised of our operations at Long Lake and future development phases. Our mining activities are conducted through our 7.23% ownership of the Syncrude Joint Venture.

Shale Gas: We explore for and produce unconventional gas from shale formations in northeast British Columbia. Production and results of operations are included within Conventional Oil and Gas until they become significant.

Corporate and Other includes energy marketing and unallocated items. The results of Canexus have been presented as discontinued operations.

The accounting policies of our operating segments are the same as those described in Note 2 of our Audited Consolidated Financial Statements for the year ended December 31, 2011. Net income (loss) of our operating segments excludes interest income, interest expense, income tax expense, unallocated corporate expenses and foreign exchange gains and losses. Identifiable assets are those used in the operations of the segments.

Segmented net income for the three months ended June 30, 2012

| | | Conventional | | | Oil Sands | | Corporate and Other | Total |
|---|---|---|---|---|---|---|---|---|
| | | United Kingdom | North America | Other Countries[1] | In Situ | Syncrude | | |
| Net Sales | | 1,028 | 88 | 217 | 173 | 145 | 8 | 1,659 |
| Marketing and Other Income | | 3 | – | – | – | 1 | 124 | 128 |
| | | 1,031 | 88 | 217 | 173 | 146 | 132 | 1,787 |
| Less: | Expenses | | | | | | | |
| | Operating | 109 | 41 | 43 | 107 | 70 | 6 | 376 |
| | Depreciation, Depletion and Amortization | 224 | 72 | 112 | 51 | 16 | 13 | 488 |
| | Transportation and Other | 5 | 9 | – | 51 | 6 | 34 | 105 |
| | General and Administrative | 3 | 22 | 9 | 11 | – | 70 | 115 |
| | Exploration | 19 | 139 | (3)[2] | – | – | – | 155 |
| | Finance | 6 | 4 | 1 | – | 2 | 68 | 81 |
| | Gain on Dispositions | – | (13) | – | (32) | – | – | (45) |
| Income (Loss) before Income Taxes | | 665 | (186) | 55 | (15) | 52 | (59) | 512 |
| Less: | Provision for Income Taxes | | | | | | | 403[3] |
| Net Income | | | | | | | | 109 |
| Capital Expenditures | | 243 | 177 | 122[4] | 127 | 62 | 12 | 743 |

1Includes results of operations in Nigeria, Yemen and Colombia.

2Includes exploration activities primarily in Colombia and Poland, and recovery of previously expensed exploration costs in Norway.

3Includes UK current tax expense of $380 million.

4Includes capital expenditures in Nigeria of $91 million.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

Segmented net income for the three months ended June 30, 2011

| | Conventional | | | Oil Sands | | Corporate and Other | Total |
|---|---|---|---|---|---|---|---|
| | United Kingdom | North America | Other Countries1,2 | In Situ | Syncrude | | |
| Net Sales | 764 | 134 | 229 | 188 | 181 | 11 | 1,507 |
| Marketing and Other Income | 1 | 30 | 3 | – | 1 | 60 | 95 |
| | 765 | 164 | 232 | 188 | 182 | 71 | 1,602 |
| Less: Expenses | | | | | | | |
| Operating | 61 | 36 | 35 | 127 | 75 | 7 | 341 |
| Depreciation, Depletion and Amortization | 133 | 116 | 23 | 36 | 14 | 13 | 335 |
| Transportation and Other | – | 11 | 11 | 51 | 6 | 33 | 112 |
| General and Administrative | 2 | 19 | 8 | 2 | – | 45 | 76 |
| Exploration | 13 | 41 | 37 3 | 2 | – | – | 93 |
| Finance | 5 | 4 | 1 | – | 2 | 48 | 60 |
| Loss on Debt Redemption | – | – | – | – | – | 1 | 1 |
| Income (Loss) before Income Taxes | 551 | (63) | 117 | (30) | 85 | (76) | 584 |
| Less: Provision for Income Taxes | | | | | | | 332 4 |
| Net Income | | | | | | | 252 |
| Capital Expenditures | 104 | 123 | 171 5 | 91 | 27 | 14 | 530 |

1Includes results of operations in Yemen and Colombia.

2Includes Yemen Masila net sales of $169 million and net income before taxes of $78 million.

3Includes exploration activities primarily in Norway, Colombia and Poland.

4Includes UK current tax expense of $323 million.

5Includes capital expenditures in Nigeria of $114 million.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

Segmented net income for the six months ended June 30, 2012

| | Conventional | | | Oil Sands | | Corporate and Other | Total |
|---|---|---|---|---|---|---|---|
| | United Kingdom | North America | Other Countries[1] | In Situ | Syncrude | | |
| Net Sales | 2,194 | 194 | 251 | 391 | 303 | 22 | 3,355 |
| Marketing and Other Income | 9 | 3 | 7 | – | 1 | 138 | 158 |
| | 2,203 | 197 | 258 | 391 | 304 | 160 | 3,513 |
| Less: Expenses | | | | | | | |
| Operating | 213 | 85 | 52 | 221 | 131 | 13 | 715 |
| Depreciation, Depletion and Amortization | 470 | 138 | 118 | 100 | 32 | 27 | 885 |
| Transportation and Other | 5 | 16 | – | 128 | 12 | 64 | 225 |
| General and Administrative | 8 | 46 | 18 | 22 | – | 147 | 241 |
| Exploration | 30 | 177 | 8 [2] | – | – | – | 215 |
| Finance | 12 | 8 | 1 | 1 | 4 | 119 | 145 |
| Gain on Dispositions | – | (13) | – | (32) | – | – | (45) |
| Income (Loss) before Income Taxes | 1,465 | (260) | 61 | (49) | 125 | (210) | 1,132 |
| Less: Provision for Income Taxes | | | | | | | 852 [3] |
| Net Income | | | | | | | 280 |
| Capital Expenditures | 438 | 432 | 252 [4] | 276 | 82 | 20 | 1,500 |

1Includes results of operations in Nigeria, Yemen and Colombia.

2Includes exploration activities primarily in Colombia and Poland, and recovery of previously expensed exploration costs in Norway.

3Includes UK current tax expense of $856 million.

4Includes capital expenditures in Nigeria of $187 million.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

Segmented net income for the six months ended June 30, 2011

| | Conventional United Kingdom | Conventional North America | Conventional Other Countries[1,2] | Oil Sands In Situ | Oil Sands Syncrude | Corporate and Other | Total |
|---|---|---|---|---|---|---|---|
| Net Sales | 1,726 | 267 | 414 | 303 | 370 | 25 | 3,105 |
| Marketing and Other Income | 17 | 32 | 7 | – | 1 | 84 | 141 |
| | 1,743 | 299 | 421 | 303 | 371 | 109 | 3,246 |
| Less: Expenses | | | | | | | |
| Operating | 159 | 76 | 70 | 234 | 150 | 15 | 704 |
| Depreciation, Depletion and Amortization | 315 | 221 | 48 | 65 | 30 | 26 | 705 |
| Transportation and Other | – | 15 | 16 | 69 | 12 | 67 | 179 |
| General and Administrative | (10) | 52 | 23 | 13 | – | 103 | 181 |
| Exploration | 17 | 100 | 100 [3] | 2 | – | – | 219 |
| Finance | 10 | 8 | 1 | 1 | 3 | 111 | 134 |
| Loss on Debt Redemption | – | – | – | – | – | 91 | 91 |
| Income (Loss) before Income Taxes | 1,252 | (173) | 163 | (81) | 176 | (304) | 1,033 |
| Less: Provision for Income Taxes | | | | | | | 881 [4] |
| Income from Continuing Operations | | | | | | | 152 |
| Add: Net Income from Discontinued Operations | | | | | | | 302 |
| Net Income | | | | | | | 454 |
| Capital Expenditures | 178 | 242 | 317 [5] | 220 | 46 | 26 | 1,029 |

1Includes results of operations in Yemen and Colombia.

2Includes Yemen Masila net sales of $315 million and net income before taxes of $135 million.

3Includes exploration activities primarily in Norway, Colombia and Poland.

4Includes UK current tax expense of $749 million.

5Includes capital expenditures in Nigeria of $214 million.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

Segmented assets as at June 30, 2012

| | Conventional | | | Oil Sands | | Corporate and Other | Total |
|---|---|---|---|---|---|---|---|
| | United Kingdom | North America | Other Countries | In Situ | Syncrude | | |
| Total Assets | 5,073 | 3,516 | 2,295 | 6,027 | 1,436 | 2,151 [1] | 20,498 |
| Property, Plant and Equipment Cost | 7,519 | 7,502 | 2,814 | 6,191 | 1,811 | 670 | 26,507 |
| Less: Accumulated DD&A | 4,122 | 4,418 | 783 | 301 | 439 | 414 | 10,477 |
| Net Book Value | 3,397 | 3,084 [2] | 2,031 [3] | 5,890 [4] | 1,372 | 256 | 16,030 |

1Includes cash of $667 million, and Energy Marketing accounts receivable, current derivative assets and inventory of $935 million.

2Includes net book value of $1,495 million associated with our Canadian shale gas operations.

3Includes net book value of $1,896 million related to our Usan development, offshore Nigeria.

4Includes net book value of $5,162 million for Long Lake Phase 1 and $728 million for future phases of our in situ oil sands projects.

Segmented assets as at December 31, 2011

| | Conventional | | | Oil Sands | | Corporate and Other | Total |
|---|---|---|---|---|---|---|---|
| | United Kingdom | North America | Other Countries | In Situ | Syncrude | | |
| Total Assets | 4,817 | 3,403 | 2,138 | 5,881 | 1,423 | 2,406 [1] | 20,068 |
| Property, Plant and Equipment Cost | 7,103 | 7,256 | 2,566 | 5,915 | 1,733 | 649 | 25,222 |
| Less: Accumulated DD&A | 3,707 | 4,299 | 648 | 205 | 411 | 381 | 9,651 |
| Net Book Value | 3,396 | 2,957 [2] | 1,918 [3] | 5,710 [4] | 1,322 | 268 | 15,571 |

1Includes cash of $453 million, and Energy Marketing accounts receivable, current derivative assets and inventory of $1,449 million.

2Includes net book value of $1,293 million associated with our Canadian shale gas operations.

3Includes net book value of $1,821 million related to our Usan development, offshore Nigeria.

4 Includes net book value of $5,050 million for Long Lake Phase 1 and $660 million for future phases of our in situ oil sands projects.

(2)The following is an extract of the audited financial statements of Nexen Group for the year ended 31 December 2011, which were prepared in accordance with IFRS, from the 2011 annual report and financial statements of Nexen Group. These financial statements were presented in C$ million dollars except for otherwise stated.

Nexen's 2011 annual report and financial statements are available free of charge, in read only, printable format on Nexen's website.

REPORT OF MANAGEMENT

February 15, 2012

To the Shareholders of Nexen Inc.

We are responsible for the preparation and fair presentation of the Consolidated Financial Statements, as well as the financial reporting process that gives rise to such Consolidated Financial Statements. This responsibility requires us to make significant accounting judgments and estimates. For example, we are required to choose accounting principles and methods that are appropriate to the company's circumstances, and we are required to make estimates and assumptions that affect amounts reported. Fulfilling this responsibility requires the preparation and presentation of our Consolidated Financial Statements in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB). Historically, we prepared our Consolidated Financial Statements under previous Canadian generally accepted accounting principles. During the year, we transitioned to IFRS. To ensure a successful transition, we initiated a company-wide project, established a qualified project team and engaged external advisors, all under the oversight of senior management and the Audit Committee.

We are responsible for developing and implementing internal controls over the financial reporting process. These controls are designed to provide reasonable assurance that relevant and reliable financial information is produced. To gather and control financial data, we have established accounting and reporting systems supported by internal controls over financial reporting and an internal audit program. We believe that our internal controls over financial reporting provide reasonable assurance that our assets are safeguarded against loss from unauthorized use or disposition, that receipts and expenditures of the company are made only in accordance with authorization of management and directors of the company and that our records are reliable for preparing our Consolidated Financial Statements and other financial information in accordance with IFRS and in accordance with applicable securities rules and regulations. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

We have established disclosure controls and procedures, internal controls over financial reporting and corporate-wide policies to ensure that Nexen's consolidated financial position, results of operations and cash flows are presented fairly. Our disclosure controls and procedures are designed to ensure timely disclosure and communication of all material information required by regulators. We oversee, with assistance from our Disclosure Review Committee, these controls and procedures and all required regulatory disclosures.

To ensure the integrity of our financial statements, we carefully select and train qualified personnel. We also ensure our organizational structure provides appropriate delegation of authority and division of responsibilities. Our policies and procedures are communicated throughout the organization and include a written ethics and integrity policy that applies to all employees, including the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer or Controller.

Our board of directors is responsible for reviewing and approving the Consolidated Financial Statements and for overseeing management's performance of its financial reporting responsibilities. Their financial statement-related responsibilities are fulfilled mainly through the Audit and Conduct Review Committee (Audit Committee), with assistance from the Reserves Review Committee regarding the annual review of our crude oil and natural gas reserves, and the Finance Committee regarding the assessment and mitigation of financial risk. The Audit Committee is composed entirely of independent directors and includes five directors with financial expertise. The Audit Committee meets regularly with management, the internal auditors and the independent registered Chartered Accountants to review accounting policies, financial reporting and internal control issues and to ensure each party is properly discharging its responsibilities. The Audit Committee is responsible for the appointment and compensation of the independent registered Chartered Accountants and also ensures their independence, reviews their fees and (subject to applicable securities laws) preapproves their retention for any permitted non-audit services. The internal auditors and independent registered Chartered Accountants have full and unlimited access to the Audit Committee, with and without the presence of management.

(signed) "Kevin J. Reinhart"
Interim President and Chief Executive Officer

(signed) "Una M. Power"
Interim Chief Financial Officer

## MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Exchange Act Rules 13(a)-15(f)). Under the supervision and with the participation of our management, including our principal executive officer (CEO) and principal financial officer (CFO), we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, we concluded that our internal control over financial reporting is effective as of December 31, 2011. We have documented this assessment and made this assessment available to our independent registered Chartered Accountants. We recognize that all internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Deloitte & Touche LLP audited our Consolidated Financial Statements as stated in their report and has provided an attestation report on our internal control over financial reporting.

REPORTS OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Nexen Inc.

We have audited the accompanying Consolidated Financial Statements of Nexen Inc. and subsidiaries (the "Company"), which comprise the consolidated balance sheet as at December 31, 2011 and 2010, and January 1, 2010, and the consolidated statements of income, cash flows, changes in equity, and comprehensive income for the years ended December 31, 2011 and 2010, and notes to the consolidated financial statements.

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 comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the Consolidated Financial Statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence 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 entity'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 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.

Opinion

In our opinion, the Consolidated Financial Statements present fairly, in all material respects, the financial position of Nexen Inc. and subsidiaries as at December 31, 2011 and 2010, and January 1, 2010, and their financial performance and cash flows for the years ended December 31, 2011 and 2010 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 15, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants
Calgary, Canada

February 15, 2012

To the Board of Directors and Shareholders of Nexen Inc.

We have audited the internal control over financial reporting of Nexen Inc. and subsidiaries (the “Company”) as of December 31, 2011, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit.

We conducted our audit 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. Our audit included 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 considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company’s internal control over financial reporting is a process designed by, or under the supervision of, the company’s principal executive and principal financial officers, or persons performing similar functions, and effected by the company’s board of directors, management, and other personnel 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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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 Consolidated Financial Statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the Consolidated Financial Statements of the Company as of and for the year ended December 31, 2011 and our report February 15, 2012 expressed an unqualified opinion on those financial statements.

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants
Calgary, Canada

February 15, 2012

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

CONSOLIDATED STATEMENT OF INCOME
For the Years Ended December 31

| (Cdn$ millions, except per-share amounts) | 2011 | 2010 |
|---|---|---|
| Revenues and Other Income | | |
| Net Sales | 6,169 | 5,496 |
| Marketing and Other Income (Note 20) | 295 | 323 |
| | 6,464 | 5,819 |
| Expenses | | |
| Operating | 1,431 | 1,336 |
| Depreciation, Depletion, Amortization and Impairment (Note 5) | 1,913 | 1,628 |
| Transportation and Other | 425 | 566 |
| General and Administrative | 300 | 428 |
| Exploration | 368 | 328 |
| Finance (Note 12) | 251 | 362 |
| Loss on Debt Redemption and Repurchase (Note 11) | 91 | – |
| Net (Gain) Loss from Dispositions (Note 23) | (38) | 41 |
| | 4,741 | 4,689 |
| Income from Continuing Operations before Provision for Income Taxes | 1,723 | 1,130 |
| Provision for (Recovery of) Income Taxes (Note 21) | | |
| Current | 1,584 | 1,125 |
| Deferred | (256) | (449) |
| | 1,328 | 676 |
| Net Income from Continuing Operations | 395 | 454 |
| Net Income from Discontinued Operations, Net of Tax (Note 23) | 302 | 673 |
| Net Income Attributable to Nexen Inc. Shareholders | 697 | 1,127 |
| Earnings Per Common Share from Continuing Operations ($/share) (Note 22) | | |
| Basic | 0.75 | 0.87 |
| Diluted | 0.69 | 0.86 |
| Earnings Per Common Share ($/share) (Note 22) | | |
| Basic | 1.32 | 2.15 |
| Diluted | 1.24 | 2.09 |

See accompanying notes to the Consolidated Financial Statements.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

CONSOLIDATED BALANCE SHEET
2011 AND 2010

| (Cdn$ millions) | December 31 2011 | December 31 2010 | January 1 2010 |
|---|---|---|---|
| ASSETS | | | |
| Current Assets | | | |
| Cash and Cash Equivalents | 845 | 1,005 | 1,700 |
| Restricted Cash | 45 | 40 | 198 |
| Accounts Receivable (Note 3) | 2,247 | 1,789 | 2,322 |
| Derivative Contracts (Note 8) | 119 | 158 | 479 |
| Inventories and Supplies (Note 4) | 320 | 550 | 680 |
| Other | 115 | 133 | 172 |
| Assets Held for Sale (Note 23) | – | 729 | – |
| Total Current Assets | 3,691 | 4,404 | 5,551 |
| | | | |
| Non-Current Assets | | | |
| Property, Plant and Equipment (Note 5) | 15,571 | 14,579 | 14,669 |
| Goodwill (Note 6) | 291 | 286 | 330 |
| Deferred Income Tax Assets (Note 21) | 338 | 160 | 75 |
| Derivative Contracts (Note 8) | 25 | 116 | 229 |
| Other Long-Term Assets (Note 7) | 152 | 102 | 101 |
| | | | |
| TOTAL ASSETS | 20,068 | 19,647 | 20,955 |
| | | | |
| LIABILITIES | | | |
| Current Liabilities | | | |
| Accounts Payable and Accrued Liabilities (Note 10) | 2,867 | 2,223 | 2,591 |
| Current Income Taxes Payable | 458 | 345 | 179 |
| Derivative Contracts (Note 8) | 103 | 168 | 482 |
| Liabilities Held for Sale (Note 23) | – | 582 | – |
| Total Current Liabilities | 3,428 | 3,318 | 3,252 |
| | | | |
| Non-Current Liabilities | | | |
| Long-Term Debt (Note 11) | 4,383 | 5,090 | 7,259 |
| Deferred Income Tax Liabilities (Note 21) | 1,488 | 1,487 | 1,678 |
| Asset Retirement Obligations (Note 14) | 2,010 | 1,516 | 1,397 |
| Derivative Contracts (Note 8) | 24 | 115 | 210 |
| Other Long-Term Liabilities (Note 15) | 362 | 307 | 372 |
| EQUITY (Note 18) | | | |
| Nexen Inc. Shareholders' Equity | | | |

| | | | |
|---|---|---|---|
| Share Capital | 1,157 | 1,111 | 1,050 |
| Retained Earnings | 7,211 | 6,692 | 5,704 |
| Cumulative Translation Adjustment | 5 | (37 ) | – |
| Total Nexen Inc. Shareholders' Equity | 8,373 | 7,766 | 6,754 |
| Canexus Non-Controlling Interests (Note 23) | – | 48 | 33 |
| | | | |
| Total Equity | 8,373 | 7,814 | 6,787 |
| | | | |
| TOTAL LIABILITIES AND EQUITY | 20,068 | 19,647 | 20,955 |

See accompanying notes to the Consolidated Financial Statements.

Approved on behalf of the Board

Kevin J. Reinhart
Director

Thomas C. O' Neill
Director

CONSOLIDATED STATEMENT OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31

| (Cdn$ millions) | 2011 | 2010 |
|---|---|---|
| Operating Activities | | |
| Net Income from Continuing Operations | 395 | 454 |
| Net Income from Discontinued Operations | 302 | 673 |
| Charges and Credits to Income not Involving Cash (Note 24) | 1,335 | 727 |
| Exploration Expense | 368 | 328 |
| Changes in Non-Cash Working Capital (Note 24) | 255 | 338 |
| Other | (158) | (128) |
| | 2,497 | 2,392 |
| Financing Activities | | |
| Repayment of Term Credit Facilities, Net | – | (1,538) |
| Repayment of Long-Term Debt (Note 11) | (871) | – |
| Proceeds from Canexus Long-Term Debt, Net | – | 112 |
| Dividends Paid on Common Shares (Note 18) | (105) | (104) |
| Issue of Common Shares and Exercise of Tandem Options for Shares (Note 18) | 46 | 55 |
| Other | (2) | (31) |
| | (932) | (1,506) |
| Investing Activities | | |
| Capital Expenditures | | |
| Exploration, Evaluation and Development | (2,431) | (2,334) |
| Proved Property Acquisitions | – | (79) |
| Corporate and Other | (93) | (243) |
| Proceeds from Dispositions | 518 | 1,264 |
| Changes in Restricted Cash | (4) | 37 |
| Changes in Non-Cash Working Capital (Note 24) | 321 | (59) |
| Other | (68) | (51) |
| | (1,757) | (1,465) |
| Effect of Exchange Rate Changes on Cash and Cash Equivalents | 32 | (116) |
| Increase (Decrease) in Cash and Cash Equivalents | (160) | (695) |
| Cash and Cash Equivalents, Beginning of Year | 1,005 | 1,700 |
| Cash and Cash Equivalents, End of Year1 | 845 | 1,005 |

1 Cash and cash equivalents at December 31, 2011 consists of cash of $283 million and short-term investments of $562 million (December 31, 2010 – cash of $345 million and short-term investments of $660 million).

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
For the Years Ended December 31

| (Cdn$ millions) | 2011 | 2010 |
|---|---|---|
| Share Capital, Beginning of Year (Note 18) | 1,111 | 1,050 |
| Issue of Common Shares | 45 | 50 |
| Exercise of Tandem Options for Shares | 1 | 5 |
| Accrued Liability Relating to Tandem Options Exercised for Common Shares | – | 6 |
| Balance at End of Year | 1,157 | 1,111 |
| Retained Earnings, Beginning of Year | 6,692 | 5,704 |
| Net Income Attributable to Nexen Inc. Shareholders | 697 | 1,127 |
| Actuarial Losses of Defined Benefit Pension Plans | (73) | (35) |
| Dividends on Common Shares | (105) | (104) |
| Balance at End of Year | 7,211 | 6,692 |
| Cumulative Translation Adjustment, Beginning of Year | (37) | – |
| Currency Translation Adjustment | 33 | (37) |
| Realized Translation Adjustments1 | 9 | – |
| Balance at End of Year | 5 | (37) |
| Canexus Non-Controlling Interests, Beginning of Year | 48 | 33 |
| Net Income Attributable to Non-Controlling Interests | 1 | 5 |
| Distributions Declared to Non-Controlling Interests | – | (17) |
| Issue of Partnership Units to Non-Controlling Interests | – | 27 |
| Disposition of Canexus (Note 23) | (49) | – |
| Balance at End of Year | – | 48 |

1 Net of income tax expense for the year ended December 31, 2011 of $18 million (2010 – net of income tax expense of $4 million).

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
For the Years Ended December 31

| (Cdn$ millions) | 2011 | 2010 |
|---|---|---|
| Net Income Attributable to Nexen Inc. Shareholders | 697 | 1,127 |
| Other Comprehensive Income (Loss): | | |
| Currency Translation Adjustment | | |
| Net Translation Gains (Losses) of Foreign Operations | 109 | (264) |
| Net Translation Gains (Losses) on US-Denominated Debt Hedging of Foreign Operations1 | (76) | 227 |
| Total Currency Translation Adjustment | 33 | (37) |
| Actuarial Losses of Defined Benefit Pension Plans2 | (73) | (35) |
| Other Comprehensive Loss | (40) | (72) |
| Total Comprehensive Income | 657 | 1,055 |

1 Net of income tax recovery for the year ended December 31, 2011 of $11 million (2010 – net of income tax expense of $32 million).
2 Net of income tax recovery for the year ended December 31, 2011 of $24 million (2010 – net of income tax recovery of $11 million).

See accompanying notes to the Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Cdn$ millions, except as noted

1. BASIS OF PRESENTATION

Nexen Inc. (Nexen, we or our) is an independent, global energy company with operations in the North Sea, Gulf of Mexico, offshore West Africa, Canada, Yemen and Colombia. Nexen is incorporated and domiciled in Canada and our head office is located at 801-7th Avenue SW, Calgary, Alberta, Canada. Nexen's shares are publicly traded on both the Toronto Stock Exchange and the New York Stock Exchange.

These Consolidated Financial Statements for the year ended December 31, 2011 have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB). Amounts relating to the year ended December 31, 2010 were previously presented in accordance with Canadian GAAP. These amounts have been restated as necessary to be compliant with our accounting policies under IFRS (see Note 2). Reconciliations and descriptions relating to the transition from Canadian GAAP to IFRS are included in Note 26.

The Consolidated Financial Statements were authorized by the board of directors for issue on February 15, 2012.

2. ACCOUNTING POLICIES

The accounting policies set out below were used to prepare the opening IFRS consolidated balance sheet at January 1, 2010 for the purposes of transitioning to IFRS, and have been applied consistently for all periods presented in these Consolidated Financial Statements.

(A)CONSOLIDATION

The Consolidated Financial Statements include the accounts of Nexen and our subsidiary companies. All subsidiary companies are wholly owned, with the exception of Canexus. All intercompany balances, transactions and profit or loss are eliminated upon consolidation.

In February 2011, we completed the sale of our 62.7% interest in Canexus. Prior to the sale, all assets, liabilities and results of operations of Canexus were consolidated and included in our 2010 Consolidated Financial Statements. Non-Nexen ownership interests in Canexus were shown as non-controlling interests. The operating results of Canexus for the twelve months ended December 31, 2011 and 2010 have been included in discontinued operations and the assets and liabilities were reclassified as held for sale as at December 31, 2010 (see Note 23).

We proportionately consolidate our undivided interests in oil and gas exploration, development and production activities conducted under joint venture arrangements. While the joint ventures under which these activities are carried out do not comprise distinct legal entities, they are operating entities. The significant operating policies of which are, by contractual arrangement, jointly controlled by all working interest parties.

(B)USE OF ESTIMATES AND JUDGMENTS

The preparation of financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Judgments, estimates and underlying assumptions are reviewed on a continuous basis and are based on management’s experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

In preparing our financial statements, we make judgments regarding the application of IFRS for our accounting policies. Significant judgments relate to the capitalization and depletion of oil and gas exploration and development costs, determination of functional currency for subsidiaries, recognition of tax assets, application of tax rules and regulations, interpretation of contracts and regulations as to what constitutes removal and remediation activities, and the identification of cash-generating units.

The financial statement areas that require significant estimates and assumptions are set out in the following paragraphs:

Oil and Gas Accounting-Reserves Determination

The process of estimating reserves is complex. It requires significant estimates based on available geological, geophysical, engineering and economic data. To estimate the economically recoverable crude oil and natural gas reserves and related future net cash flows, we incorporate many factors and assumptions including the expected reservoir characteristics, future commodity prices and costs and assumed effects of regulation by governmental agencies. Reserves are used to calculate the depletion of the capitalized oil and gas costs and for impairment purposes as described in Note 2(G).

Property, Plant and Equipment

We evaluate our long-lived assets (oil and gas properties and goodwill) for impairment if indicators exist. Cash flow estimates for our impairment assessments require assumptions and estimates about the following primary elements-future prices, future operating and development costs, remaining recoverable reserves and discount rates. In assessing the carrying values of our unproved properties, we make assumptions about our future plans for those properties, the remaining terms of the leases and any other factors that may be indicators of potential impairment.

Asset Retirement Obligations

In estimating our future asset retirement obligations, we make assumptions about activities that occur many years into the future including the cost and timing of such activities. The ultimate financial impact is not clearly known as asset removal and remediation techniques and costs are constantly changing, as are legal, regulatory, environmental, political, safety and other such considerations. In arriving at amounts recorded, numerous assumptions and estimates are made on ultimate settlement amounts, inflation factors, discount rates, timing and expected changes in legal, regulatory, environmental, political and safety environments.

Contingencies

By their nature, contingencies will only be resolved when one or more future events transpire. The assessment of contingencies inherently involves estimating the outcome of future events.

Income Taxes

We carry on business in several countries and as a result, are subject to income taxes in numerous jurisdictions. The determination of income tax is inherently complex and we are required to make certain estimates and assumptions about future events. While income tax filings are subject to audits and reassessments, we believe we have adequately provided for all income tax obligations. However, changes in facts and circumstances as a result of income tax audits, reassessments, jurisprudence and any new legislation may result in an increase or decrease in our provision for income taxes.

Derivatives and Fair Value Measurements

The fair value of derivative contracts is estimated wherever possible, based on quoted market prices, and if not available, on estimates from third-party brokers. Another significant assumption that we use in determining the fair value of derivatives is market data or assumptions that market participants would use when pricing the asset or liability, including assumptions about risk. The actual settlement of derivatives could differ materially from the fair value recorded and could impact future results.

(C) CASH AND CASH EQUIVALENTS

Cash and cash equivalents includes short-term, highly liquid investments that mature within three months of their purchase.

(D) RESTRICTED CASH

Restricted cash includes margin deposits relating to our exchange-traded derivative contracts used in our energy marketing business.

(E) ACCOUNTS RECEIVABLE

Accounts receivable are recorded based on our revenue recognition policy (see Note 2(N)). Our allowance for doubtful accounts provides for specific doubtful receivables, as well as general counterparty credit risk evaluated using observable market information and internal assessments.

(F) INVENTORIES AND SUPPLIES

Inventories and supplies, other than inventory held for trading purposes by our energy marketing group, are stated at the lower of cost and net realizable value. Cost is determined using the first-in, first-out method Inventory costs include expenditures and other costs, including depletion and depreciation, directly or indirectly incurred in bringing the inventory to its location and existing condition.

Commodity inventories in our energy marketing operations that are held for trading purposes are carried at fair value, less any costs to sell. Any changes in fair value are included as gains or losses in marketing and other income during the period of change.

(G) PROPERTY, PLANT AND EQUIPMENT (PP&E)

PP&E includes capitalized costs related to our exploration and evaluation expenditures, assets under construction and producing oil and gas properties.

Exploration and Evaluation (E&E) Expenditures

Pre-License Expenditures

Pre-license expenditures are expensed in the period in which they are incurred.

License and Property Acquisition Expenditures

Exploration license and leasehold property acquisition expenditures are intangible assets that are capitalized as E&E costs in PP&E and are reviewed periodically for indications of potential impairment. This review includes confirming that exploration drilling is under way, firmly planned or that it has been determined or work is under way to determine, that the discovery is economically viable based on a range of technical and commercial considerations, and sufficient progress is being made to establish development plans and timing. If no future activity is planned, the remaining balance of the capitalized license and property acquisition costs is expensed. Licenses are amortized on a straight-line basis over the estimated period of exploration. Once proved reserves are discovered, technical feasibility and commercial viability are established and we decide to proceed with development, the remaining capitalized expenditure is transferred to either assets under construction or producing oil and gas properties.

Other Exploration and Evaluation Expenditures

Other exploration and evaluation costs, including drilling costs directly attributable to an identifiable exploration or appraisal well, are initially capitalized as an intangible asset until evaluation activities of the exploration play are completed. If hydrocarbons are not found, or not found in commercial quantities, the costs are expensed. If hydrocarbons are found and are likely to be capable of commercial development, the costs continue to be capitalized. These costs are reviewed periodically for indications of potential impairment. Capitalized costs are transferred to assets under construction or producing oil and gas properties after assessing the estimated fair value of the property and recognizing any potential impairment loss. Geological and geophysical costs and annual lease rental costs are expensed as incurred.

Producing Oil and Gas Properties

Producing oil and gas properties are carried at cost less accumulated depletion, depreciation, amortization, and impairment losses. The cost of an asset includes the initial purchase price and directly attributable expenditures to find, develop, construct and complete the asset. This includes installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including unsuccessful development or delineation wells. Any costs directly attributable to bringing the asset to the location and condition necessary to operate as intended by management and which result in an identifiable future benefit are also capitalized. This includes the estimate of any asset retirement obligation and, for qualifying assets, capitalized interest. Improvements that increase capacity or extend the useful lives of the related assets are capitalized. Major spare parts and standby equipment whose useful life is expected to last longer than one year are included in capitalized costs.

Major Maintenance and Repairs

Expenditures on major maintenance of our producing assets include the cost of replacement assets or parts of assets, inspection costs or overhaul costs. Where an asset, or part of an asset that was separately depreciated, is replaced and it is probable that there are future economic benefits associated with the item, the expenditure is capitalized and the carrying amount of the replaced item is derecognized. Inspection costs associated with major maintenance programs and necessary for continued operation of the asset are capitalized and amortized over the period to the next inspection.

All other maintenance costs are expensed as incurred.

Research and Development

We engage in research and development activities to develop or improve processing techniques to extract crude oil and natural gas. Research involves investigations to gain new knowledge. Development involves translating that knowledge into a new technology or process. Research costs are expensed as incurred. Development costs are deferred once technical feasibility is established and we intend to proceed with development. We defer these costs in PP&E until the asset is substantially complete and ready for productive use. Otherwise, development costs are expensed as incurred.

Non-Monetary Asset Swaps

Exchanges or swaps of non-monetary assets are measured at fair value unless the exchange transaction lacks commercial substance or neither the fair value of the assets given up nor the assets received can be reliably estimated. The cost of the acquired asset is measured at the fair value of the asset given up, unless the fair value of the asset received is more clearly evident. Where fair value is not used, the cost of the acquired asset is measured at the carrying amount of the asset given up. Any gain or loss on derecognition of the asset given up is included in net income.

Depreciation, Depletion, Amortization and Impairment (DD&A)

Unproved property costs and major projects under construction or development are not depreciated or depleted until commercial production commences. We amortize unproved land acquisition costs over the remaining lease term.

We review the useful lives of capitalized costs for producing oil and gas properties to determine the appropriate method of amortization. We deplete oil and gas capitalized costs using the unit-of-production method. Development drilling, equipping costs and other facility costs are depleted over remaining proved developed reserves and proved property acquisition costs are depleted over remaining proved reserves. Other facilities, plant and equipment which have significantly different useful lives than the associated proved reserves are depreciated in accordance with the asset’s future use which range from two to 40 years. Depletion is considered a cost of inventory when the oil and gas is produced. When the inventory is sold, the depletion is charged to DD&A expense.

Depreciation methods, useful lives and residual values are reviewed annually, with any amendments considered to be a change in estimate and accounted for prospectively.

Impairment

Each reporting date, we assess whether there is an indication that an asset may be impaired. If any indication exists, we estimate the asset's recoverable amount. An asset's recoverable amount is the higher of an asset's or cash-generating unit's (CGU) fair value less any costs to sell or value-in-use. Where an asset does not generate separately identifiable cash flows, we perform an impairment test on CGUs, which are the smallest grouping of assets that generate independent, identifiable cash inflows. Where the carrying amount of an asset or CGU exceeds its recoverable amount, the asset is considered impaired and written down to its recoverable amount. In assessing value-in-use, the estimated future cash flows are discounted to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. In determining fair value less costs to sell, an appropriate valuation model is used. These calculations are corroborated by external valuation metrics or other available fair value indicators wherever possible.

In assessing the carrying values of our unproved properties, we take into account future plans for those properties, the remaining terms of the leases and any other factors that may be indicators of potential impairment.

For assets excluding goodwill, an assessment is made each reporting date as to whether there is an indication that previously recognized impairment losses no longer exist or have decreased. If such indication exists, an estimate of the asset's or CGU's recoverable amount is reviewed. A previously recognized impairment loss is reversed to the extent that the events or circumstances that triggered the original impairment have changed. The reversal is limited so that the carrying amount of the asset does not exceed its recoverable amount, nor exceed the carrying amount that would have been determined, net of DD&A, had no impairment loss been recognized for the asset in prior periods.

(H)CAPITALIZED BORROWING COSTS

We capitalize interest on major development projects until construction is complete using the weighted-average interest rate on all of our borrowings. Capitalized interest cannot exceed the actual interest incurred.

(I)CARRIED INTEREST

We conduct certain international operations jointly with foreign governments in accordance with production-sharing agreements pursuant to which proved reserves are recognized using the economic interest method. Under these agreements, we pay both our share and the government's share of operating and capital costs. We recover the government's share of these costs from future revenues or production over several years. The government's share of operating costs is included in operating expense when incurred, and capital costs are included in PP&E and expensed to DD&A in the year recovered. All recoveries are recorded as revenue in the year of recovery.

(J)GOODWILL

Goodwill acquired in a business combination is initially recorded at cost, and for impairment testing purposes, is allocated to each of the CGUs that are expected to benefit from the expenditure. After initial recognition, goodwill is measured at cost less any accumulated impairment losses. We test goodwill for impairment at least annually as at December 31, or more frequently if events or circumstances indicate that goodwill may be impaired. We base our test on the assessment of the recoverable amount of the CGU. Where the recoverable amount of the CGU is less than the carrying amount, we reduce the carrying value to the estimated recoverable amount and a goodwill impairment loss is included in net income.

(K)FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

All financial assets and liabilities are recognized on the balance sheet initially at fair value when we become a party to the contractual provisions of the instrument. Subsequent measurement of the financial instruments is based on their classification. We classify each financial instrument into one of the following categories: financial assets and liabilities at fair value through profit or loss, loans or receivables, financial assets held to maturity, financial assets available for sale and other financial liabilities. The classification depends on the characteristics and the purpose for which the financial instruments were acquired. Except in limited circumstances, the classification of financial instruments is not subsequently changed.

Financial instruments carried at fair value on our balance sheet include cash and cash equivalents, restricted cash and derivatives. Realized and unrealized gains and losses from financial assets and liabilities carried at fair value are recognized in net income in the periods such gains and losses arise. Transaction costs related to these financial assets and liabilities are included in net income when incurred.

Financial instruments carried at cost or amortized cost include our accounts receivable, accounts payable and accrued liabilities, short-term borrowings and long-term debt. These transaction costs are included with the initial fair value, and the instrument is carried at amortized cost using the effective interest rate method. Gains and losses on financial assets and liabilities carried at cost or amortized costs are recognized in net income when these assets and liabilities settle.

Derivatives

We use derivative instruments such as physical purchase and sales contracts, exchange-traded futures and options, and non-exchange traded forwards, swaps and options for marketing crude oil and natural gas and to manage fluctuations in commodity prices, foreign currency exchange rates and interest rates. We record these instruments at fair value at each balance sheet date and changes in fair value are included in marketing and other income during the period of change unless the requirements for hedge accounting are met.

Hedge accounting

Hedge accounting is allowed when there is a high degree of correlation between price movements in the derivative instruments and the items designated as being hedged. Nexen formally documents all hedges and the risk management objectives at the inception of the hedge. Derivative instruments that have been designated and qualify for hedge accounting are classified as either cash flow or fair value hedges.

For cash flow hedges, changes in the fair value of a financial instrument designated as a cash flow hedge are recognized in net income in the same period as the hedged item. Any fair value change in the financial instrument before that period is recognized on the balance sheet. The effective portion of this fair value change is recognized in other comprehensive income, with any ineffectiveness recognized in net income during the period of change.

For fair value hedges, both the financial instrument designated as a fair value hedge and the underlying commitment are recognized on the balance sheet at fair value. Changes in the fair value of both are reflected in net income.

For hedges of net investments, gains and losses resulting from foreign exchange translation of our net investments in foreign operations and the effective portion of the hedging items are recorded in other comprehensive income.

Amounts included in cumulative translation adjustment are reclassified to net income when realized.

(L)PROVISIONS AND CONTINGENCIES

Provisions are recognized when we have a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where appropriate, the future cash flow estimates are adjusted to reflect the risks specific to the liability.

If the effect of the time value of money is material, provisions are determined by discounting the expected future cash flows at a discount rate that reflects current market assessments of the time value of money. Where discounting is used, the accretion of the provision due to the passage of time is recognized within finance costs.

Contingent liabilities are possible obligations which will be confirmed by future events that are not necessarily within our control, or are present obligations where the obligation cannot be measured reliably or it is not probable that settlement will be required. Contingent liabilities are disclosed only if the possibility of settlement is greater than remote. Contingent liabilities are not recorded in the financial statements.

Asset Retirement Obligations and Environmental Expenditures

We provide for asset retirement obligations (ARO) on our resource properties, facilities, production platforms, pipelines and other facilities based on estimates established by current legislation and industry practices. ARO is initially measured at fair value and capitalized to PP&E as an asset retirement cost. The liability is estimated by discounting expected future cash flows required to settle the liability using a risk-free rate. The estimated future asset retirement costs may be adjusted for risks such as project, physical, regulatory and timing. The estimates are reviewed periodically. Changes in the provision as a result of changes in the estimated future costs or discount rates are added to or deducted from the cost of the PP&E in the period of the change. The liability accretes for the effect of time value of money until it is expected to settle. The asset retirement cost is amortized through DD&A over the life of the related asset. Actual asset retirement expenditures are recorded against the obligation when incurred. Any difference between the accrued liability and the actual expenditures incurred is recorded as a gain or loss in the settlement period.

Liabilities for environmental costs are recognized when a clean-up is probable and the associated costs can be reliably estimated. Environmental expenditures that relate to current or future revenues are expensed or capitalized as appropriate.

(M)PENSION AND OTHER POST-RETIREMENT BENEFITS

Our employee post-retirement benefit programs consist of defined benefit and defined contribution pension plans, as well as other post-retirement benefit programs.

For our defined benefit plans, we provide retirement benefits to employees based on their length of service and final average earnings. The cost of pension benefits earned by employees in our defined benefit pension plans is actuarially determined using the projected-benefit method prorated on service and our best estimate of the plans' investment performance, salary escalations and retirement ages of employees. To calculate the plans' expected returns, assets are measured at fair value. Fair value measurement of the defined benefit assets are limited to the sum of any recognized net actuarial losses and past service costs, and the net present value of any economic benefit available in the form of surplus refunds to the plan or reductions in future contributions to the plan. Vested past service costs arising from plan amendments are recognized in other comprehensive income (OCI) immediately. Unvested past service costs are amortized over the expected average service life until they become vested. Net actuarial gains and losses are included in OCI as incurred with immediate recognition in retained earnings. Benefits paid out of Nexen's defined benefit plan are indexed to 75% of the annual rate of inflation less 1% to a maximum increase of 5%. The measurement date for our defined benefit plans is December 31.

Our defined contribution pension plan benefits are based on plan contributions. Company contributions to the defined contribution plan are expensed as incurred.

Other post-retirement benefits include group life and supplemental health insurance for eligible employees and their dependants. Costs are accrued as compensation in the period employees work; however, these future obligations are not funded.

### (N)REVENUE RECOGNITION

Revenue from the production of oil and gas is recognized when title passes to the customer. In Canada and the US, our customers primarily take title when the oil or gas reaches the end of the pipeline. For our other international operations, our customers generally take title when the crude oil is loaded onto tankers. When we sell more or less crude oil or natural gas than we produce, production overlifts and underlifts occur. We record overlifts as liabilities at fair value and underlifts as assets at cost. We settle these over time as liftings are equalized or in cash when production ends.

Revenue represents Nexen's share and is recorded net of royalty obligations to governments and other mineral interest owners. For our international operations, all government interests, except for income taxes, are considered royalty obligations. Our revenue also includes the recovery of carried interest costs paid on behalf of foreign governments in international locations.

### (O)FOREIGN CURRENCY TRANSLATION

Our foreign operations are translated from their functional currency into Canadian dollars at the balance sheet date exchange rate for assets and liabilities and at the monthly average exchange rate for revenues and expenses. Gains and losses resulting from this translation are included in other comprehensive income.

We have designated our US-dollar debt as a hedge against our net investment in US-dollar foreign operations. Gains and losses resulting from the translation of the designated US-dollar debt are included in other comprehensive income. If our US-dollar debt, net of income taxes, exceeds our US-dollar investment in foreign operations, then the translation gains or losses attributable to such excess are included in net income.

Monetary balance sheet amounts denominated in a currency other than a functional currency are translated into the functional currency using exchange rates at the balance sheet dates. Gains and losses arising from this translation are included in net income. Non-monetary balance sheet amounts denominated in a currency other than a functional currency are translated using historical exchange rates at the time of the transaction.

### (P)TRANSPORTATION

We pay to transport the oil and gas products that we have sold and often bill our customers for the transportation. This transportation cost is included in transportation and other expense. Amounts billed to our customers are presented within marketing and other income.

### (Q)LEASES

We classify leases entered into as either finance or operating leases. Leases that transfer substantially all of the risks and benefits of ownership to us are capitalized as finance leases within PP&E and other liabilities. All other leases are recorded as operating leases and expensed as incurred within operating expenses.

### (R)STOCK-BASED COMPENSATION

Our stock-based compensation programs consist of tandem option (TOPs), stock appreciation right (STARs), restricted share unit (RSUs) and deferred share unit (DSUs) plans.

TOPs to purchase common shares are granted to officers and employees at the discretion of the board of directors. Each TOP gives the holder a right to either purchase one Nexen common share at the exercise price or to receive a cash payment equal to the excess of the market price of the common share over the exercise price. TOPs granted vest over three years and are exercisable on a cumulative basis over five years. At the time of the grant, the exercise price equals the market price of the common share. In 2010, certain TOPs granted contained a performance vesting condition.

We record obligations for the outstanding TOPs using the fair-value method of accounting and recognize compensation expense in net income. Obligations are accrued on a graded vesting basis and revalued each reporting period based on the change in the estimated fair value of the options outstanding. We reduce the liability when the options are surrendered for cash. When the options are exercised for stock, the accrued liability is transferred to share capital.

Under our STARs plan, employees are entitled to cash payments equal to the excess of market price of the common share over the exercise price of the right. The vesting period and other terms of the plan are similar to the TOPs plan and include a performance vesting condition for certain awards. At the time of grant, the exercise price equals the market price of the common share. We account for STARs to employees on the same basis as our TOPs. Obligations are accrued as compensation expense over the graded vesting period of the STARs.

The fair value of each TOP and STAR is estimated using a Black-Scholes option pricing methodology, which takes into account share performance, market conditions, and other terms and conditions. For those awards that contain a performance vesting condition, we use the Monte Carlo option pricing model to simulate expected returns and estimate the fair value. This is applied to the reward criteria of the performance TOPs and STARs to give an expected value each measurement date.

Under our RSU plan, employees are entitled to receive a cash payment equal to the average closing market price of one common share for the 20 days prior to the vesting date for each RSU granted. All RSUs vest evenly over three years and are exercised and paid automatically as they vest. The liability for RSUs is revalued each period based on the market price of our common shares and the number of graded vested RSUs outstanding. Beginning in 2011, certain RSUs granted contain a performance vesting condition.

For employees eligible to retire during the vesting period, the compensation expense is recognized over the period from the grant date to the retirement eligibility date on a graded vesting basis. In instances where an employee is eligible to retire on the grant date of the stock-based award, compensation expense is recognized in full at that date.

DSUs are equity-based awards granted to directors. The units accumulate over a director’s term of service and vest when the director leaves the board. Payments may be made in cash or in Nexen common shares purchased on the open market at the company’s discretion. At the time of grant, the exercise price equals the market value of Nexen common shares.

(S)INCOME TAXES

The provision for income taxes comprises current amounts payable and deferred tax provisions. The provision for income taxes is recognized in net income except to the extent that it relates to items recognized directly in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to taxes payable in respect of previous years. Current tax assets and liabilities are offset to the extent the entity has the legal right to settle on a net basis.

Deferred tax assets and liabilities are recognized for temporary differences between reported amounts for financial statement and tax purposes. Deferred tax is not recognized for the following temporary differences: i) initial recognition of tax assets or liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit or loss, ii) differences relating to investments in subsidiaries to the extent that it is probable that they will not reverse in the foreseeable future, and iii) the initial recognition of goodwill. Deferred tax assets are only recognized for temporary differences, unused tax losses and unused tax credits if it is probable that future tax amounts will arise to utilize those amounts.

Deferred tax assets and liabilities are measured at tax rates that are expected to be applied to temporary differences when they reverse, based on the tax rates and laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and tax liabilities are offset to the extent there is a legal right to settle on a net basis.

We do not provide for foreign withholding taxes on the undistributed earnings of our foreign subsidiaries, as we intend to invest such earnings in the respective foreign operations.

(T)CHANGES IN ACCOUNTING POLICIES

As part of our transition to IFRS, we have adopted all IFRS accounting standards in effect on December 31, 2011.

The following standards and interpretations have not been adopted as they apply to future periods. They may result in future changes to our existing accounting policies and other note disclosures. We are evaluating the impacts that these standards may have on our results of operations, financial position and disclosure, except where indicated.

IFRS 7 Financial Instruments: Disclosures – in December 2011, the International Accounting Standards Board (IASB) issued final amendments to the disclosure requirements for the offsetting of a financial asset and financial liabilities when offsetting is permitted under IFRS. The disclosure amendments are required to be adopted retrospectively for periods beginning January 1, 2013.

IFRS 9 Financial Instruments – in November 2009, the IASB issued IFRS 9 to address classification and measurement of financial assets. In October 2010, the IASB revised the standard to include financial liabilities. The standard is required to be adopted for periods beginning January 1, 2015. Portions of the standard remain in development and the full impact of the standard will not be known until the project is complete.

IFRS 10 Consolidated Financial Statements – in May 2011, the IASB issued IFRS 10 which provides additional guidance to determine whether an investee should be consolidated. The guidance applies to all investees, including special purpose entities. The standard replaces IAS 27 (which still contains guidance on separate financial statements) and is required to be adopted for periods beginning January 1, 2013. We do not expect the adoption of this standard to impact our results of operations or financial position.

IFRS 11 Joint Arrangements – in May 2011, the IASB issued IFRS 11 which presents a new model for determining whether an entity should account for joint arrangements using proportionate consolidation or the equity method. An entity will have to follow the substance rather than legal form of a joint arrangement and will no longer have a choice of accounting method. The standard also amends IAS 28 to include joint ventures and is required to be adopted for periods beginning January 1, 2013.

IFRS 12 Disclosure of Interests in Other Entities – in May 2011, the IASB issued IFRS 12 which aggregates and amends disclosure requirements included within other standards. The standard requires companies to provide disclosures about subsidiaries, joint arrangements, associates and unconsolidated structured entities. The standard is required to be adopted for periods beginning January 1, 2013. We expect this standard to result in additional disclosures in our financial statements.

IFRS 13 Fair Value Measurement – in May 2011, the IASB issued IFRS 13 to provide comprehensive guidance for instances where IFRS requires fair value to be used. The standard provides guidance on determining fair value and requires disclosures about those measurements. The standard is required to be adopted for periods beginning January 1, 2013. We do not expect a material impact on our results of operations or financial position.

IAS 1 Presentation of Items of Other Comprehensive Income – in June 2011, the IASB issued amendments to IAS 1 Presentation of Financial Statements to separate items of other comprehensive income (OCI) between those that are reclassed to income and those that do not. The standard is required to be adopted for periods beginning on or after July 1, 2012. We do not expect a significant change to our presentation of items of other comprehensive income.

IAS 19 Employee Benefits – in June 2011, the IASB issued amendments to IAS 19 to revise certain aspects of the accounting for pension plans and other benefits. The amendments eliminate the corridor method of accounting for defined benefit plans, change the recognition pattern of gains and losses and require additional disclosures. The standard is required to be adopted for periods beginning on or after January 1, 2013.

IAS 32 Financial Instruments: Presentation – in December 2011, the IASB issued amendments to address inconsistencies when applying the offsetting criteria outlined in this standard. These amendments clarify certain of the criteria required to be met in order to permit the offsetting of financial assets and financial liabilities. The standard is required to be adopted retrospectively for periods beginning January 1, 2014.

## 3. ACCOUNTS RECEIVABLE

| | December 31 2011 | December 31 2010 | January 1 2010 |
|---|---|---|---|
| Trade | | | |
| Energy Marketing | 1,146 | 929 | 1,410 |
| Oil and Gas | 1,037 | 822 | 823 |
| Other | 3 | 2 | 44 |
| | 2,186 | 1,753 | 2,277 |
| Non-Trade | 73 | 80 | 99 |
| | 2,259 | 1,833 | 2,376 |
| Allowance for Doubtful Receivables1 | (12) | (44) | (54) |
| Total2 | 2,247 | 1,789 | 2,322 |

1 Includes a general provision of $1 million and a specific provision against certain accounts. In 2011, allowance for doubtful receivables decreased as a result of reassessing prior impairment provisions. In 2010, allowance for doubtful receivables decreased primarily from a reduction in counterparty credit reserves.

2 At December 31, 2010, accounts receivable related to our chemicals operations have been included with assets held for sale (see Note 23).

Receivables terms are up to 30 days and were current as of December 31, 2011, December 31, 2010 and January 1, 2010.

## 4. INVENTORIES AND SUPPLIES

| | December 31 2011 | December 31 2010 | January 1 2010 |
|---|---|---|---|
| Finished Products | | | |

| | | | |
|---|---|---|---|
| Energy Marketing | 230 | 452 | 548 |
| Oil and Gas | 36 | 35 | 25 |
| Other | – | – | 12 |
| | 266 | 487 | 585 |
| Work in Process | 6 | 5 | 7 |
| Field Supplies | 48 | 58 | 88 |
| Total1 | 320 | 550 | 680 |

1 At December 31, 2010, inventories and supplies related to our chemicals operations have been included with assets held for sale (see Note 23).

5. PROPERTY, PLANT AND EQUIPMENT

(A) CARRYING AMOUNT OF PP&E

| | Exploration and Evaluation | Assets Under Construction | Producing Oil & Gas Properties | Corporate and Other | Total |
|---|---|---|---|---|---|
| Cost | | | | | |
| As at January 1, 2010 | 2,393 | 1,045 | 20,020 | 1,849 | 25,307 |
| Additions | 1,092 | 693 | 696 | 243 | 2,724 |
| Disposals/Derecognitions | (70) | (8) | (1,638) | (122) | (1,838) |
| Transfers | (82) | 78 | 4 | – | – |
| Exploration Expense | (328) | – | – | – | (328) |
| Transferred to Held for Sale | – | – | – | (1,207) | (1,207) |
| Other | 36 | 15 | 408 | (3) | 456 |
| Effect of Changes in Exchange Rate | (51) | (75) | (603) | (3) | (732) |
| As at December 31, 2010 | 2,990 | 1,748 | 18,887 | 757 | 24,382 |
| Additions | 1,056 | 734 | 693 | 92 | 2,575 |
| Disposals/Derecognitions | (303) | – | (2,004) | (18) | (2,325) |
| Transfers | (1,253) | (216) | 1,469 | – | – |
| Exploration Expense | (368) | – | – | – | (368) |
| Other | 65 | 31 | 493 | – | 589 |
| Effect of Changes in Exchange Rate | 19 | 50 | 294 | 6 | 369 |
| As at December 31, 2011 | 2,206 | 2,347 | 19,832 | 837 | 25,222 |
| Accumulated Depreciation, Depletion & Amortization (DD&A) | | | | | |
| As at January 1, 2010 | 360 | 11 | 9,325 | 942 | 10,638 |
| DD&A | 41 | – | 1,384 | 119 | 1,544 |
| Disposals/Derecognitions | (59) | (8) | (1,378) | (62) | (1,507) |
| Impairments | – | – | 139 | – | 139 |
| Transferred to Held for Sale | – | – | – | (578) | (578) |
| Other | 1 | – | (7) | (5) | (11) |
| Effect of Changes in Exchange Rate | (12) | (3) | (409) | 2 | (422) |
| As at December 31, 2010 | 331 | – | 9,054 | 418 | 9,803 |
| DD&A | 50 | – | 1,210 | 78 | 1,338 |
| Disposals/Derecognitions | (12) | – | (1,938) | (75) | (2,025) |
| Impairments | – | – | 322 | – | 322 |
| Other | (6) | – | (8) | – | (14) |
| Effect of Changes in Exchange Rate | 5 | – | 220 | 2 | 227 |
| As at December 31, 2011 | 368 | – | 8,860 | 423 | 9,651 |

| | | | | | |
|---|---|---|---|---|---|
| Net Book Value | | | | | |
| As at January 1, 2010 | 2,033 | 1,034 | 10,695 | 907 | 14,669 |
| As at December 31, 2010 | 2,659 | 1,748 | 9,833 | 339 | 14,579 |
| As at December 31, 2011 | 1,838 | 2,347 | 10,972 | 414 | 15,571 |

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

Exploration and evaluation assets mainly comprise of unproved properties and capitalized exploration drilling costs. Assets under construction primarily include our Usan development, offshore Nigeria and developments in the UK North Sea.

(B) IMPAIRMENT

DD&A expense for 2011 includes non-cash impairment charges of $322 million for our oil and gas properties in our Conventional North America segment. Canadian natural gas assets were impaired $234 million in the second half of 2011 due to lower estimated future natural gas prices and performance-related negative reserve revisions. In the fourth quarter, lower estimated future natural gas prices and higher estimated future abandonment costs resulted in an $88 million impairment of mature Gulf of Mexico properties.

DD&A expense for 2010 includes non-cash impairment charges of $139 million for properties in the US Gulf of Mexico and Canada. In the second half of 2010, low natural gas prices, higher estimated future abandonment costs and declining production performance impaired these properties.

The properties were written down to the higher amount of value-in-use and estimated fair value less costs to sell. We estimated fair value based on discounted future net cash flows using estimated future prices, a discount rate of 9% and management's estimate of future production, capital and operating expenditures.

(C) ASSET DERECOGNITIONS

Nexen's original strategy for future oil sands development was to build duplicates of the existing Long Lake SAGD facilities and upgrader. We now expect to pursue smaller, phased, SAGD-only projects and we will consider adding upgrading capacity once we are bitumen-long and economic conditions are favourable. As a result, previously capitalized design and engineering costs of $253 million on the future phases have been expensed.

6. GOODWILL

(A) CARRYING AMOUNT OF GOODWILL

Goodwill

| | |
|---|---|
| As at January 1, 2010 | 330 |
| Effect of Changes in Exchange Rate | (15) |
| Dispositions | (29) |
| As at December 31, 2010 | 286 |
| Effect of Changes in Exchange Rate | 7 |
| Dispositions | (2) |
| As at December 31, 2011 | 291 |

| | December 31 | December 31 | January 1 |
|---|---|---|---|

| | 2011 | 2010 | 2010 |
|---|---|---|---|
| UK Conventional | 284 | 277 | 292 |
| Corporate and Other | 7 | 9 | 38 |
| | | | |
| Total | 291 | 286 | 330 |

(B) IMPAIRMENT TESTING OF GOODWILL

Goodwill is attributable to our UK Conventional and Corporate and Other segments which have been allocated for impairment testing purposes to the cash-generating units that reflect the lowest level at which goodwill is attributable.

UK Conventional

The recoverable amount of the UK group was based on cash flow projections discounted at a rate of 9%. The significant assumptions used in the cash flow projections are:

Commodity prices: these assumptions are based on estimated future prices, the global supply-demand balance for each commodity, other macroeconomic factors, historical trends and variability.

Discount rates: the rates used in the calculation are based on an industry-specific discount rate, adjusted to take into consideration country and project risks specific to the cash-generating unit.

Production volumes, capital investment and operating costs: estimated future operational activities and costs are based on current estimated asset development plans, past experience and available knowledge about costs and reservoir performance.

7. OTHER LONG-TERM ASSETS

| | December 31 2011 | December 31 2010 | January 1 2010 |
|---|---|---|---|
| Long-Term Capital Prepayments | 46 | 43 | 27 |
| Defined Benefit Pension Asset (Note 16) | – | 21 | 21 |
| Long-Term Investments | 41 | – | – |
| Other | 65 | 38 | 53 |
| | | | |
| Total1 | 152 | 102 | 101 |

1 At December 31, 2010, other long-term assets related to our chemical operations have been included in assets held for sale (see Note 23).

8. FINANCIAL INSTRUMENTS

Financial instruments carried at fair value on our balance sheet include cash and cash equivalents, restricted cash and derivatives used for trading and non-trading purposes. Our other financial instruments, including accounts receivable, accounts payable and accrued liabilities, current income taxes payable, short-term borrowings and long-term debt, are carried at cost or amortized cost. The carrying value of our short-term receivables and payables approximates fair value because the instruments are near maturity.

(A) DERIVATIVES

In our energy marketing group, we enter into contracts to purchase and sell crude oil, natural gas and other energy commodities, and use derivative contracts, including futures, forwards, swaps and options, for hedging and trading purposes (collectively derivative contracts). We also use derivatives to manage commodity price risk and foreign currency risk for non-trading purposes. We categorize our derivative instruments between trading and non-trading activities and carry the instruments at fair value on our balance sheet. The fair values are included in derivative contracts and are classified as long-term or short-term based on anticipated settlement date and, where applicable, are presented net on the balance sheet in accordance with netting arrangements. Any change in fair value is included in marketing and other income. Related amounts posted as margin for exchange-traded positions are recorded in restricted cash.

Total carrying value of derivative contracts

The fair value and carrying amounts related to derivative contracts are as follows:

| | December 31 2011 | December 31 2010 | January 1 2010 |
|---|---|---|---|
| Commodity Contracts | 119 | 158 | 476 |
| Foreign Exchange Contracts | – | – | 3 |
| Derivative Contracts – Current | 119 | 158 | 479 |
| Commodity Contracts | 25 | 116 | 229 |
| Derivative Contracts – Long-Term1 | 25 | 116 | 229 |
| Total Derivative Assets | 144 | 274 | 708 |
| Commodity Contracts | 103 | 168 | 436 |
| Foreign Exchange Contracts | – | – | 46 |
| Derivative Contracts – Current | 103 | 168 | 482 |
| Commodity Contracts | 24 | 115 | 210 |
| Derivative Contracts – Long-Term1 | 24 | 115 | 210 |
| Total Derivative Liabilities | 127 | 283 | 692 |
| Total Net Derivative Contracts | 17 | (9) | 16 |

1 These derivative contracts settle beyond 12 months and are considered non-current.

Derivative contracts related to trading

Our energy marketing group primarily focuses on crude oil marketing activities in North American and international markets. During 2010, we sold substantially all of our North American natural gas marketing operations, our oil lease gathering, pipeline and storage assets in North Dakota and Montana and our European gas and power marketing operations, as described in Note 23.

Trading revenues generated by our energy marketing group include gains and losses on derivative instruments and non-derivative instruments such as physical inventory. During the years ended December 31, 2011 and 2010, the following revenues were recognized in marketing and other income:

| | 2011 | 2010 |
|---|---|---|
| Commodity | 200 | 342 |
| Foreign Exchange | (5) | (5) |
| Marketing Revenue, Net | 195 | 337 |

Derivative contracts related to non-trading activities

During 2011, we purchased crude oil put options on 100,000 bbls/d of our 2012 crude oil production for $52 million. These options establish a monthly Dated Brent floor price of US$65/bbl on 60,000 bbls/d and an annual Dated Brent floor price of $75/bbl on 40,000 bbls/d. The put options provide a base level of price protection without limiting our upside to higher prices. The options settle monthly or annually and unexpired options are recorded at fair value throughout their term. As a result, changes in forward crude oil prices create gains or losses on these options at each reporting period. At December 31, 2011, higher crude oil prices reduced the fair value of the options to approximately $38 million, and we recorded a fair value loss during the period of $14 million in marketing and other income.

In 2010, we purchased put options on 100,000 bbls/d of our 2011 crude oil production for $33 million. These options established a monthly WTI floor price between US$50/bbl and US$63/bbl on these volumes. At December 31, 2010, higher crude oil prices reduced the fair value of the options to $9 million, and we recorded a fair value loss of $24 million during 2010 in marketing and other income. Strengthening crude prices in 2011 reduced the fair value of these options to nil and we recorded a fair value loss of $9 million in 2011.

| | December 31, 2011 | | | | |
|---|---|---|---|---|---|
| | Notional Volumes (bbls/d) | Term | Average Floor Price (US$/bbl) | Fair Value (Cdn$ millions) | Change in Fair Value (Cdn millions) |
| Dated Brent Crude Oil Put Options (annual) | 40,000 | 2012 | 75 | 16 | |
| Dated Brent Crude Oil Put Options (monthly) | 60,000 | 2012 | 65 | 22 | |

| | December 31, 2010 | | | | |
|---|---|---|---|---|---|
| | Notional Volumes (bbls/d) | Term | Average Floor Price (US$/bbl) | Fair Value (Cdn$ millions) | Change in Fair Value (Cdn millions) |
| WTI Crude Oil Put Options (monthly) | 100,000 | 2011 | 56 | 9 | (24 ) |

(B) FAIR VALUE OF FINANCIAL INSTRUMENTS

Fair value of derivatives

For purposes of estimating the fair value of our derivative contracts, wherever possible, we utilize quoted market prices and, if not available, estimates from third-party brokers. These broker estimates are corroborated with multiple sources and/or other observable market data utilizing assumptions that market participants would use when pricing the asset or liability, including assumptions about risk and market liquidity. Inputs may be readily observable, market-corroborated or generally unobservable. We utilize valuation techniques that seek to maximize the use of observable inputs and minimize the use of unobservable inputs. To value longer-term transactions and transactions in less active markets for which pricing information is not generally available, unobservable inputs may be used.

We classify financial instruments carried at fair value according to the following hierarchy based on the amount of observable inputs used to value the instruments.

| | |
|---|---|
| Level – 1 | Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 consists of financial instruments such as exchange-traded derivatives, and we use information from markets such as the New York Mercantile Exchange. |
| Level – 2 | Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reported date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value, volatility factors and broker quotations, which can be substantially observed or corroborated in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter physical forwards and options, including those that have prices similar to quoted market prices. We obtain information from sources such as the Natural Gas Exchange, independent price publications and over-the-counter broker quotes. |
| Level – 3 | Valuations in this level are those with inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value. Level 3 instruments may include items based on pricing services or broker quotes where we are unable to verify the observability of inputs into their prices. Level 3 instruments include longer- term transactions, transactions in less active markets or transactions at locations for which pricing information is not available. In these instances, internally developed methodologies are used to determine fair value, which primarily includes extrapolation of observable future prices to |

similar locations, similar instruments or later time periods.

Cash and restricted cash are valued using level 1 inputs. The following tables include our derivatives carried at fair value for our trading and non-trading activities as at December 31, 2011 and 2010 and as at January 1, 2010. Financial assets and liabilities are classified in the fair value hierarchy in their entirety based on the lowest level of input that is significant to the fair value measurement. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect placement within the fair value hierarchy levels.

| Net Derivatives at December 31, 2011 | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Trading Derivatives | (17) | (1) | (3) | (21) |
| Non-Trading Derivatives | – | 38 | – | 38 |
| Total | (17) | 37 | (3) | 17 |

| Net Derivatives at December 31, 2010 | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Trading Derivatives | (17) | (18) | 17 | (18) |
| Non-Trading Derivatives | – | 9 | – | 9 |
| Total | (17) | (9) | 17 | (9) |

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

| Net Derivatives at January 1, 2010 | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Trading Derivatives | (143 ) | 126 | 42 | 25 |
| Non-Trading Derivatives | – | (9 ) | – | (9 ) |
| Total | (143 ) | 117 | 42 | 16 |

A reconciliation of changes in the fair value of our derivatives classified as Level 3 for the years ended December 31, 2011 and 2010 is provided below:

| | 2011 | 2010 |
|---|---|---|
| Level 3 Net Derivatives at January 1 | 17 | 42 |
| Realized and Unrealized Gains (Losses) | (34 ) | 19 |
| Settlements | 14 | (44 ) |
| Level 3 Net Derivatives at December 31 | (3 ) | 17 |
| Unsettled Gains (Losses) Relating to Instruments Still Held as of December 31 | (3 ) | 19 |

Items classified in Level 3 are generally economically hedged such that gains or losses on positions classified in Level 3 are often offset by gains or losses on positions classified in Level 1 or 2. We performed a sensitivity analysis of inputs used to calculate the fair value of Level 3 instruments. Using reasonably possible alternative assumptions, the fair value of Level 3 instruments at December 31, 2011 could change by $8 million.

Fair value of long-term debt

We carry our long-term debt at amortized cost using the effective interest method. At December 31, 2011, the estimated fair value of our long-term debt was $4,848 million (December 31, 2010 – $5,290 million) as compared to the carrying value of $4,383 million (December 31, 2010 –$5,090 million). The fair value of long-term debt is estimated based on prices provided by quoted markets and third-party brokers.

## 9. RISK MANAGEMENT

### (A) MARKET RISK

We invest in significant capital projects, purchase and sell commodities, issue short-term borrowings and long-term debt, and invest in foreign operations. These activities expose us to market risks from changes in commodity prices, foreign currency rates and interest rates, which could affect our earnings and the value of the financial instruments we hold. We use derivatives as part of our overall risk management policy to manage these market exposures.

The following market risk discussion focuses on the commodity price risk and foreign currency risk related to our financial instruments as our exposure to interest rate risk is immaterial given that the majority of our debt is fixed rate.

Commodity price risk

We are exposed to commodity price movements as part of our normal oil and gas operations, particularly in relation to the prices received for our crude oil and natural gas. Commodity price risk related to crude oil prices is our most significant market risk exposure. Crude oil and natural gas prices are sensitive to numerous worldwide factors, many of which are beyond our control, and are generally sold at contract or posted prices. Changes in the global supply and demand fundamentals in the crude oil market and geopolitical events can significantly affect crude oil prices. Changes in crude oil and natural gas prices may significantly affect our results of operations and cash generated from operating activities. Consequently, these changes may also affect the value of our oil and gas properties, our level of spending for exploration and development, and our ability to meet our obligations as they come due.

The majority of our oil and gas production is sold under short-term contracts, exposing us to the risk of price movements. Other energy contracts we enter into also expose us to commodity price risk between the time we purchase and sell contracted volumes. We actively manage these risks by using derivative contracts such as commodity put options.

We market and trade physical energy commodities, including crude oil, natural gas and other commodities in selected regions of the world. We accomplish this by buying and selling physical commodities, by acquiring and holding rights to physical transportation and storage assets for these commodities, and by building relationships with our customers and suppliers. In order to manage the commodity and foreign exchange price risks that come from this physical business, we use financial derivative contracts including energy-related futures, forwards, swaps and options, as well as foreign currency swaps or forwards.

Our risk management activities make use of tools such as Value-at-Risk (VaR) and stress testing. VaR is a statistical estimate of the expected profit or loss of a portfolio of positions assuming normal market conditions. We use a 95% confidence interval and an assumed five-day holding period in our measure, although actual results can differ from this estimate in abnormal market conditions, or if positions are held longer than five days based on market views or a lack of market liquidity to exit them. We estimate VaR primarily by using the Variance-Covariance method based on historical commodity price volatility and correlation inputs where available, and by historical simulation in other situations. Our estimate is based upon the following key assumptions:

- changes in commodity prices are either normally or “T” distributed;
- price volatility is comparable to prior periods; and
- price correlation relationships remain stable.

We have defined VaR limits for different segments of our energy marketing business. These limits are calculated on an economic basis and include physical and financial derivatives, as well as physical transportation and storage capacity contracts accounted for as executory contracts in our financial statements. We monitor our positions against these VaR limits daily. Our year-end, annual high, annual low and average VaR amounts are as follows:

| (Cdn$ millions) | 2011 | 2010 |
|---|---|---|
| Value-at-Risk | | |
| Year-End | 7 | 17 |
| High | 17 | 24 |
| Low | 2 | 6 |
| Average | 9 | 16 |

If a significant market shock occurred, the key assumptions underlying our VaR estimate could be exceeded and the potential loss could be greater than our estimate. We perform stress tests on a regular basis to complement VaR and assess the impact of abnormal changes in prices on our positions.

Foreign currency risk

Foreign currency risk is created by fluctuations in the fair values or cash flows of financial instruments due to changes in foreign exchange rates. A substantial portion of our activities are transacted in or referenced to US dollars including:

sales of crude oil and natural gas products;

capital spending and expenses in our oil and gas activities;

commodity derivative contracts used primarily by our energy marketing group; and

short-term borrowings and long-term debt.

We manage our exposure to fluctuations between the US and Canadian dollar by matching our expected net cash flows and borrowings in the same currency. Cash flows generated by our foreign operations and borrowings on our US-dollar debt facilities are generally used to fund US-dollar capital expenditures and debt repayments. We maintain revolving Canadian and US-dollar borrowing facilities that can be drawn upon or repaid depending on expected new cash flows.

We designate most of our US-dollar borrowings as a hedge against our US-dollar net investment in our foreign operations. The accumulated foreign exchange gains or losses related to the effective portion of our designated US-dollar debt are included in cumulative translation adjustment in shareholders' equity. Our net investment in foreign operations and our designated US-dollar debt at December 31, 2011 and 2010 are as follows:

| (US$ millions) | December 31 2010 | December 31 2011 |
|---|---|---|
| Net Investment in Foreign Operations | 4,191 | 4,680 |
| Designated US-Dollar Debt | 3,673 | 3,842 |

A one-cent change in the US dollar to Canadian dollar exchange rate would increase or decrease our cumulative translation adjustment by approximately $37 million, net of income tax, and would not have a material impact on our net income.

We also have exposures to currencies other than the US dollar, including a portion of our UK operating expenses, capital spending and future asset retirement obligations, which are denominated in British Pounds and Euros. We do not have any material exposure to highly inflationary foreign currencies. Our energy marketing group enters into transactions in various currencies including Canadian and US dollars, British Pounds and Euros. We may actively manage significant currency exposures using forward contracts and swaps.

Our sensitivities to the US/Canadian dollar exchange rate and the expected impact of a one-cent change on our 2012 cash flow from operating activities, net income, capital expenditures and long-term debt are as follows:

| (Cdn$ millions) | Cash Flow | Net Income | Capital Expenditures | Long-Term Debt |
|---|---|---|---|---|
| $0.01 Change in US to Cdn | 30 | 14 | 20 | 44 |

(B) CREDIT RISK

Credit risk affects our oil and gas operations and our energy marketing activities, and is the risk of loss if counterparties do not fulfill their contractual obligations. Most of our credit exposures are with counterparties in the energy industry, including integrated oil companies, refiners and utilities, and are subject to normal industry credit risk. Over 75% of our exposure is with these large energy companies. This concentration of risk within the energy industry is reduced because of our broad base of domestic and international counterparties. We take the following measures to reduce this risk:

assess the financial strength of our counterparties through a credit analysis process;

limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;

routinely monitor credit risk exposures, including sector, geographic and corporate concentrations of credit, and report these to management and the board of directors;

set and regularly review counterparty credit limits based on rating agency credit ratings and internal assessments of company and industry analysis; and

use standard agreements where possible that allow for the netting of exposures associated with a single counterparty.

We believe these measures minimize our overall credit risk; however, there can be no assurance that these processes will protect us against all losses from non-performance.

At December 31, 2011, only three counterparties individually made up more than 10% of our credit exposure. These counterparties are major integrated oil companies with strong investment-grade credit ratings.

The following table illustrates the composition of credit exposure by credit rating:

| | December 31 2010 | | December 31 2011 | |
|---|---|---|---|---|
| Credit Rating | | | | |
| A or higher | 60 | % | 71 | % |
| BBB | 31 | % | 20 | % |
| Non-Investment Grade | 9 | % | 9 | % |
| Total | 100 | % | 100 | % |

Our maximum counterparty credit exposure at the balance sheet date consists primarily of the carrying amounts of non-derivative financial assets such as cash and cash equivalents, restricted cash, accounts receivable, as well as the fair value of derivative financial assets. We have provided a general allowance of $1 million for credit risk with our counterparties.

Collateral received from customers at December 31, 2011 includes $17 million of cash and $568 million of letters of credit. The cash received is included in accounts payable and accrued liabilities.

(C) LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations as they fall due. We require liquidity specifically to fund capital requirements, satisfy financial obligations as they become due, and to operate our energy marketing business. We generally rely on operating cash flows to provide liquidity as well as maintain significant undrawn committed credit facilities. At December 31, 2011, we had approximately $4.2 billion of cash and available committed lines of credit. This includes $845 million of cash and cash equivalents on hand and undrawn term credit facilities of $3.8 billion, of which $367 million was supporting letters of credit at December 31, 2011. Of these term credit facilities, $3.1 billion is available until 2016, with the remainder available until 2014. We also had $393 million of uncommitted, unsecured credit facilities, of which $21 million was supporting letters of credit outstanding at December 31, 2011. Of these uncommitted facilities, $213 million is available exclusively for supporting letters of credit.

The following table details the contractual maturities for our non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2011:

| (Cdn$ millions) | Total | < 1 Year | 1-3 Years | 4-5 Years | > 5 Years |
|---|---|---|---|---|---|
| Long-Term Debt | 4,463 | – | – | 128 | 4,335 |
| Cumulative Interest on Long-Term Debt1 | 6,978 | 301 | 601 | 589 | 5,487 |
| | | | | | |
| Total | 11,441 | 301 | 601 | 717 | 9,822 |

1 At December 31, 2011, none of our variable interest rate debt was drawn.

The following table details contractual maturities for our derivative financial liabilities at December 31, 2011. The consolidated balance sheet amounts for derivative financial liabilities included below are not materially different from the contractual amounts due on maturity.

| (Cdn$ millions)<br><br>Net Derivative Contracts | Total | < 1 Year | 1-3 Years | 4-5 Years | > 5 Years |
|---|---|---|---|---|---|
| (Note 8) | 127 | 103 | 23 | 1 | – |

At December 31, 2011, collateral posted with counterparties includes $388 million of letters of credit. Cash posted is included with accounts receivable. Cash collateral is not normally applied to contract settlement. Once a contract has been settled, the collateral amounts are refunded. If there is a default, the cash is retained.

The commercial agreements our energy marketing group enter into often include financial assurance provisions that allow us and our counterparties to effectively manage credit risk. The agreements normally require collateral to be posted if an adverse credit-related event occurs, such as a drop in credit ratings to non-investment grade. Based on the derivative contracts in place and commodity prices at December 31, 2011, we could be required to post collateral of approximately $704 million if we were downgraded to non-investment grade. These obligations are reflected on our balance sheet and the posting of collateral merely secures the payment of such amounts. We have significant undrawn credit facilities and cash to fund these potential collateral requirements.

Our exchange-traded derivative contracts are also subject to margin requirements. We have margin deposits at December 31, 2011 of $45 million (2010 – $40 million), which have been included in restricted cash.

10. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

| | December 31 2011 | December 31 2010 | January 1 2010 |
|---|---|---|---|
| Energy Marketing Payables | 1,287 | 1,016 | 1,366 |
| Accrued Payables | 1,035 | 676 | 619 |

| | | | |
|---|---|---|---|
| Trade Payables | 288 | 164 | 210 |
| Other | 122 | 147 | 108 |
| Accrued Interest Payable | 78 | 83 | 89 |
| Stock-Based Compensation | 31 | 111 | 173 |
| Dividends Payable | 26 | 26 | 26 |
| | | | |
| Total1 | 2,867 | 2,223 | 2,591 |

1At December 31, 2010, accounts payable and accrued liabilities related to our chemical operations have been included in liabilities held for sale (see Note 23).

11. LONG-TERM DEBT

| | December 31 2011 | December 31 2010 | January 1 2010 |
|---|---|---|---|
| Term Credit Facilites (A) | – | – | 1,570 |
| Notes, due 2013 (B) | – | 497 | 523 |
| Notes, due 2015 (US$126 million) (C) | 128 | 249 | 262 |
| Notes, due 2017 (US$62 million) (D) | 63 | 249 | 262 |
| Notes, due 2019 (US$300 million) (E) | 305 | 298 | 314 |
| Notes, due 2028 (US$200 million) (F) | 203 | 199 | 209 |
| Notes, due 2032 (US$500 million) (G) | 509 | 497 | 523 |
| Notes, due 2035 (US$790 million) (H) | 804 | 786 | 827 |
| Notes, due 2037 (US$1,250 million) (I) | 1,271 | 1,243 | 1,308 |
| Notes, due 2039 (US$700 million) (J) | 712 | 696 | 733 |
| Subordinated Debentures, due 2043 (US$460 million) (K) | 468 | 457 | 481 |
| | 4,463 | 5,171 | 7,012 |
| Unamortized Debt Issue Costs | (80) | (81) | (88) |
| | 4,383 | 5,090 | 6,924 |
| Canexus Debt1 | – | – | 335 |
| Total | 4,383 | 5,090 | 7,259 |

1At December 31, 2010, long term debt related to our chemical operations have been included in liabilities held for sale (see Note 23).

(A) TERM CREDIT FACILITIES

We have committed unsecured term credit facilities of $3.8 billion (US$3.7 billion), which were not drawn at either December 31, 2011 or December 31, 2010 (January 1, 2010 – $1.6 billion (US$1.5 billion)). Of these facilities, $700 million is available until 2014 and $3.1 billion is available until 2016. Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime rate loans, US-dollar base rate loans or British pound call-rate loans. Interest is payable at floating rates. At December 31, 2011, $367 million of these facilities were utilized to support outstanding letters of credit (December 31, 2010 –$322 million and January 1, 2010 – $407 million).

(B) NOTES, DUE 2013

During November 2003, we issued US$500 million of notes. Interest was payable semi-annually at a rate of 5.05% and the principal was to be repaid in November 2013. In 2011, we redeemed and cancelled these notes. We paid $525 million for the redemption. We recorded a $52 million loss as the difference between carrying value and the redemption price.

(C) NOTES, DUE 2015

During March 2005, we issued US$250 million of notes. Interest is payable semi-annually at a rate of 5.2% and the principal is to be repaid in March 2015. In 2011, we repurchased and cancelled US$124 million of principal of these notes. We paid $135 million for the repurchase and recorded a $14 million loss as the difference between the carrying value and the redemption price. At December 31, 2011, US$126 million of notes remain outstanding. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.15%.

(D) NOTES, DUE 2017

During May 2007, we issued US$250 million of notes. Interest is payable semi-annually at a rate of 5.65% and the principal is to be repaid in May 2017. In 2011, we repurchased and cancelled US$188 million of principal of these notes. We paid $211 million for the repurchase and recorded a $25 million loss as the difference between the carrying value and the redemption price. At December 31, 2011, US$62 million of notes remain outstanding. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to maturity equal to the remaining term of the notes plus 0.20%.

(E) NOTES, DUE 2019

During July 2009, we issued US$300 million of notes. Interest is payable semi-annually at a rate of 6.2% and the principal is to be repaid in July 2019. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.40%.

(F) NOTES, DUE 2028

During April 1998, we issued US$200 million of notes. Interest is payable semi-annually at a rate of 7.4% and the principal is to be repaid in May 2028. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.25%.

(G) NOTES, DUE 2032

During March 2002, we issued US$500 million of notes. Interest is payable semi-annually at a rate of 7.875% and the principal is to be repaid in March 2032. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.375%.

(H) NOTES, DUE 2035

During March 2005, we issued US$790 million of notes. Interest is payable semi-annually at a rate of 5.875% and the principal is to be repaid in March 2035. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.20%.

(I) NOTES, DUE 2037

During May 2007, we issued US$1,250 million of notes. Interest is payable semi-annually at a rate of 6.4% and the principal is to be repaid in May 2037. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.35%.

(J) NOTES, DUE 2039

During July 2009, we issued US$700 million of notes. Interest is payable semi-annually at a rate of 7.5% and the principal is to be repaid in July 2039. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.45%.

(K) SUBORDINATED DEBENTURES, DUE 2043

During November 2003, we issued US$460 million of unsecured subordinated debentures. Interest is payable quarterly at a rate of 7.35%, and the principal is to be repaid in November 2043. We may redeem part or all of the debentures at any time. The redemption price is equal to the par value of the principal amount plus any accrued and unpaid interest to the redemption date. We may choose to redeem the principal amount with either cash or common shares.

(L) LONG-TERM DEBT REPAYMENTS

The following schedule outlines the required timetable of debt repayments and does not preclude earlier repayments as per the provisions of the respective notes.

| | |
|---|---|
| 2012 | – |
| 2013 | – |
| 2014 | – |
| 2015 | 128 |
| 2016 | – |
| Thereafter | 4,335 |
| Total | 4,463 |

(M) DEBT COVENANTS

Some of our debt instruments contain covenants with respect to certain financial ratios and our ability to grant security. We are required to maintain a debt to EBITDA ratio of less than 3.5. For the year ended December 31, 2011, this ratio was 0.95 times (2010 – 1.29). At December 31, 2011, December 31, 2010 and January 1, 2010, we were in compliance with all covenants.

(N) CREDIT FACILITIES

Nexen has uncommitted, unsecured credit facilities of approximately $180 million (US$178 million), none of which were drawn at December 31, 2011, December 31, 2010 or January 1, 2010. We utilized $17 million of these facilities to support outstanding letters of credit at December 31, 2011 (December 31, 2010– $112 million and January 1, 2010 – $86 million). Interest is payable at floating rates. Nexen has uncommitted, unsecured credit facilities exclusive to letters of credit of approximately $213 million (US$210 million). We utilized $4 million of these facilities to support outstanding letters of credit at December 31, 2011 (December 31, 2010 – nil and January 1, 2010 – nil).

12. FINANCE EXPENSE

| | 2011 | 2010 |
|---|---|---|
| Long-Term Debt Interest Expense | 304 | 361 |
| Accretion Expense Related to Asset Retirement Obligations | 44 | 47 |
| Other Interest Expense and Fees | 27 | 34 |
| Total | 375 | 442 |
| Less: Capitalized at 6.7% (2010 – 5.8%) | (124) | (80) |
| Total1 | 251 | 362 |

1 Excludes finance expense related to our chemical operations (see Note 23).

Capitalized interest relates to and is included as part of the cost of our oil and gas properties. The capitalization rates are based on our weighted-average cost of borrowings.

13. CAPITAL MANAGEMENT

Our objective for managing our capital structure is to ensure that we have the financial capacity, liquidity and flexibility to fund our investment in full-cycle exploration and development of conventional and unconventional resources and for our energy marketing activities. We generally rely on operating cash flows to fund capital investments. However, given the long cycle-time of some of our development projects, which require significant capital investment prior to cash flow generation, and volatile commodity prices, it is not unusual for capital expenditures to exceed our cash flow from operating activities in any given period. As such, our financing needs depend on the timing of expected net cash flows in a particular development or commodity cycle. This requires us to maintain financial flexibility and liquidity. Our capital management policies are aimed at:

maintaining an appropriate balance between short-term borrowings, long-term debt and equity;

maintaining sufficient undrawn committed credit capacity to provide liquidity;

ensuring ample covenant room permitting us to draw on credit lines as required; and

ensuring we maintain a credit rating that is appropriate for our circumstances.

We have the ability to change our capital structure by issuing additional equity or debt, returning cash to shareholders and making adjustments to our capital investment programs. Our capital consists of equity, short-term borrowings, long-term debt and cash and cash equivalents as follows:

| | December 31 2011 | December 31 2010 | January 1 2010 |
|---|---|---|---|
| Net Debt1 | | | |
| Long-Term Debt | 4,383 | 5,090 | 7,259 |
| Less: Cash and Cash Equivalents | (845) | (1,005) | (1,700) |
| Total2 | 3,538 | 4,085 | 5,559 |
| Equity3 | 8,373 | 7,814 | 6,787 |

1 Includes all of our borrowings and is calculated as long-term debt and short-term borrowings less cash and cash equivalents.
2 December 31, 2010 excludes net debt related to our chemical operations that are included in assets and liabilities held for sale (see Note 23).
3 Equity is the historical issue of equity and accumulated retained earnings.

We monitor the leverage in our capital structure and the strength of our balance sheet by reviewing the ratio of net debt to adjusted cash flow (cash flow from operating activities before changes in non-cash working capital and other).

Net debt and adjusted cash flow are non-GAAP measures that are unlikely to be comparable to similar measures presented by others. We calculate net debt using the GAAP measures of long-term debt and short-term borrowings less cash and cash equivalents (excluding restricted cash).

For the twelve months ended December 31, 2011 the net debt to adjusted cash flow was 1.5 times compared to 1.9 times at December 31, 2010. While we typically expect the target ratio to fluctuate between 1.0 and 2.0 times under normalized commodity prices, this can be higher or lower depending on commodity price volatility, where we are in the investment cycle, or when we identify strategic opportunities requiring additional investment. Whenever we exceed our target ratio, we assess whether we need to develop a strategy to reduce our leverage and lower this ratio back to target levels over time. Our objectives for managing our capital structure or targets have not changed from last year.

14. ASSET RETIREMENT OBLIGATIONS

Changes in carrying amounts of our ARO provision are as follows:

| | 2011 | 2010 |
|---|---|---|
| ARO, Beginning of Year | 1,571 | 1,432 |
| Obligations Incurred with Development Activities | 69 | 81 |
| Changes in Estimates | 450 | 332 |
| Obligations Related to Dispositions | (9) | (224) |
| Obligations Settled | (72) | (43) |
| Accretion | 44 | 47 |
| Effects of Changes in Foreign Exchange Rates | 23 | (54) |
| ARO, End of Year1 | 2,076 | 1,571 |
| Of which: | | |
| Due Within Twelve Months2 | 66 | 55 |
| Due After Twelve Months | 2,010 | 1,516 |

1At December 31, 2010, asset retirement obligations related to our chemicals operations have been included in liabilities held for sale (see Note 23).

2Included in accounts payable and accrued liabilities.

ARO represents the present value of estimated remediation and reclamation costs associated with our PP&E. We discounted the estimated asset retirement obligation using a weighted-average credit-adjusted risk-free rate of 2.6% (2010 – 3.3%). While the provision for abandonment is based on our best estimates of future costs and the economic lives of the assets involved, there is uncertainty regarding both the amount and timing of incurring these costs. We expect approximately $428 million included in our ARO will be settled over the next five years with the balance settling beyond that. We expect to fund ARO from future cash flows from our operations.

15. OTHER LONG-TERM LIABILITIES

| | December 31 2011 | December 31 2010 | January 1 2010 |
|---|---|---|---|
| Defined Benefit Pension Obligations | 208 | 159 | 139 |
| Finance Lease Obligations | 41 | 42 | 61 |
| Other | 113 | 106 | 172 |
| Total1 | 362 | 307 | 372 |

1At December 31, 2010, other long-term liabilities related to our chemicals operations have been included in liabilities held for sale (see Note 23).

## 16. PENSION AND OTHER POST-RETIREMENT BENEFITS

Nexen has defined benefit and defined contribution pension plans, as well as other post-retirement benefit programs, which cover substantially all employees. Syncrude has a defined benefit plan for its employees, and we disclose only our proportionate share of this plan.

### (A) DEFINED BENEFIT PENSION PLANS

The cost of pension benefits earned by employees is determined using the projected-benefit method prorated on employment services and is expensed as services are rendered. We fund these plans according to federal and provincial government regulations by contributing to trust funds administered by an independent trustee. These funds are invested primarily in equities and bonds. Nexen's supplemental benefit plan is funded from our operating cash flows and the year-end obligation of $120 million is backed by an irrevocable letter of credit.

| | 2011 | | | | |
|---|---|---|---|---|---|
| | Registered (Funded) | Nexen Supplemental1 (Unfunded) | Total | Syncrude | Total |
| Benefit Obligations | | | | | |
| Beginning of Year | 291 | 97 | 388 | 151 | 539 |
| Service Cost | 21 | 5 | 26 | 6 | 32 |
| Interest Cost | 16 | 5 | 21 | 8 | 29 |
| Plan Participants' Contributions | 6 | – | 6 | 1 | 7 |
| Actuarial Loss | 25 | 16 | 41 | 29 | 70 |
| Benefits Paid | (15) | (3) | (18) | (6) | (24) |
| End of Year1 | 344 | 120 | 464 | 189 | 653 |
| Plan Assets | | | | | |
| Beginning of Year | 312 | – | 312 | 87 | 399 |
| Expected Return on Plan Assets2 | 21 | – | 21 | 7 | 28 |
| Employer's Contribution | 26 | 3 | 29 | 13 | 42 |
| Plan Participants Contributions | 6 | – | 6 | 1 | 7 |
| Actuarial (Loss) Gain on Plan Assets2 | (22) | – | (22) | (5) | (27) |
| Benefits Paid | (15) | (3) | (18) | (5) | (23) |
| End of Year | 328 | – | 328 | 98 | 426 |
| Net Pension Liability | (16) | (120) | (136) | (91) | (227) |
| Pension Liability | | | | | |
| Accounts Payable and Accrued Liabilities | (6) | (4) | (10) | (9) | (19) |
| Other Long-Term Liabilities(Note 15) | (10) | (116) | (126) | (82) | (208) |
| Net Pension Liability | (16) | (120) | (136) | (91) | (227) |
| Assumptions (%) | | | | | |
| Accrued Benefit Obligation at December 31 | | | | | |
| Discount Rate | | | 4.50 | 4.25 | |
| Long-Term Rate of Employee Compensation Increase | | | 4.00 | 4.50 | |
| Inflation Rate | | | 2.00 | 5.00 | |
| Benefit Cost for Year Ended December 31 | | | | | |

| | | |
|---|---|---|
| Discount Rate | 5.25 | 4.25 |
| Long-Term Annual Rate of Return on Plan Assets3 | 6.75 | 7.30 |

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

| | 2010 | | | | |
|---|---|---|---|---|---|
| | Registered (Funded) | Nexen Supplemental1 (Unfunded) | Total | Syncrude | Total |
| Projected Benefit Obligations | | | | | |
| Beginning of Year | 243 | 76 | 319 | 125 | 444 |
| Service Cost | 17 | 4 | 21 | 5 | 26 |
| Interest Cost | 15 | 5 | 20 | 7 | 27 |
| Plan Participants' Contributions | 6 | – | 6 | 1 | 7 |
| Actuarial Loss (Gain) | 26 | 15 | 41 | 19 | 60 |
| Benefits Paid | (16) | (3) | (19) | (6) | (25) |
| End of Year1 | 291 | 97 | 388 | 151 | 539 |
| Plan Assets | | | | | |
| Beginning of Year | 264 | – | 264 | 69 | 333 |
| Expected Return on Plan Assets2 | 20 | – | 20 | 6 | 26 |
| Employer's Contribution | 30 | 3 | 33 | 14 | 47 |
| Plan Participants' Contribution | 6 | – | 6 | 1 | 7 |
| Actuarial (Loss) Gain on Plan Assets2 | 8 | – | 8 | 2 | 10 |
| Benefits Paid | (16) | (3) | (19) | (5) | (24) |
| End of Year | 312 | – | 312 | 87 | 399 |
| Net Pension Liability | 21 | (97) | (76) | (64) | (140) |
| Pension Liability | | | | | |
| Other Long-Term Assets | 21 | – | 21 | – | 21 |
| Accounts Payable and Accrued Liabilities | – | (2) | (2) | – | (2) |
| Other Long-Term Liabilities | – | (95) | (95) | (64) | (159) |
| Net Pension Liability | 21 | (97) | (76) | (64) | (140) |

| | Nexen | Syncrude |
|---|---|---|
| Assumptions (%) | | |
| Accrued Benefit Obligation at December 31 | | |
| Discount Rate | 5.25 | 5.25 |
| Long-Term Rate of Employee Compensation Increase | 4.00 | 4.45 |
| Inflation Rate | 2.50 | 3.00 |
| Benefit Cost for Year Ended December 31 | | |
| Discount Rate | 6.00 | 5.25 |
| Long-Term Annual Rate of Return on Plan Assets3 | 7.00 | 7.50 |

1

Includes self-funded obligations for supplemental benefits to the extent that the benefit is limited by statutory guidelines. The self-funded obligations for supplemental benefits are backed by irrevocable letters of credit.

2Reconciliation between expected and actual return on plan assets:

| | 2011 | 2010 |
|---|---|---|
| Expected Return on Plan Assets | 28 | 26 |
| Actuarial Gain (Loss) on Plan Assets | (27) | 10 |
| Actual Return on Plan Assets | 1 | 36 |

3The long-term annual rate of return on plan assets assumption is based on a mix of historical market returns for debt and equity securities.

Defined Benefit Pension Plan Expense

| | 2011 | 2010 |
|---|---|---|
| Nexen | | |
| Cost of Benefits Earned by Employees | 26 | 21 |
| Interest Cost on Benefits Earned | 21 | 20 |
| Expected Return on Plan Assets1 | (21) | (20) |
| Net Pension Expense | 26 | 21 |
| Syncrude2 | | |
| Cost of Benefit Earned by Employees | 6 | 5 |
| Interest Cost on Benefits Earned | 8 | 7 |
| Expected Return on Plan Assets3 | (7) | (6) |
| Net Pension Expense | 7 | 6 |
| Total Net Pension Expense4 | 33 | 27 |

1Actual loss on Nexen plan assets was $1 million (2010 – $28 million).

2Nexen’s share of Syncrude’s employee pension plans.

3Actual gain on Syncrude plan assets was $2 million (2010 – $8 million gain).

4Net pension expense is reported principally within operating expense and general and administrative expense in the Consolidated Statement of Income.

(B) PLAN ASSET ALLOCATION AT DECEMBER 31

Our investment goal for the assets in our defined benefit pension plans is to preserve capital and earn a long-term rate of return on assets, net of all management expenses, in excess of the inflation rate. Investment funds are managed by external fund managers based on policies approved by the board of directors and pension management committee of Nexen. Nexen's investment strategy is to diversify plan assets between debt and equity securities of Canadian and non-Canadian corporations that are traded on recognized stock exchanges. Allowable and prohibited investment types are also prescribed in Nexen's investment policies.

Nexen's investment strategy is to ensure appropriate diversification between and within asset classes in order to optimize the return/risk trade-off. Nexen's policy allows investment in equities, fixed income, cash and real estate assets. Derivative instruments can be utilized as deemed appropriate by the pension management committee. Nexen's expected long-term annual rate of return on plan assets assumption is based on a mix of historical market returns for debt and equity securities. The returns that are used as the basis for future expectations are derived from the major asset categories that Nexen is currently invested in.

The target allocations for plan assets are identified in the table below. Equity securities primarily include investments in large-cap companies, both Canadian and foreign, and debt securities primarily include corporate bonds of companies from diversified industries and Canadian Treasury issuances. The Canadian fixed income pooled funds invest in low-cost fixed income index funds that track the DEX Universe Bond Index. The Canadian equity pooled funds invest in low-cost equity funds that track the S&P/ TSX Composite Index. The foreign equity pooled funds invest in low-cost equity index funds that track the S&P 500 and MSCI EAFE Indexes.

Nexen also has an unregistered self-funded supplemental defined benefits pension plan that covers obligations that are limited by statutory guidelines. These benefits are backed by an irrevocable letter of credit and payments are made from Nexen's general operating revenues. Syncrude's pension plan is governed and administered separately from ours. Syncrude's plan assets are subject to similar investment goals, policies and strategies.

| Plan Asset Allocation (%) | Expected 2012 | 2011 | 2010 |
|---|---|---|---|
| Nexen | | | |
| Equity Securities | 65 | 65 | 65 |
| Debt Securities | 35 | 35 | 35 |
| Total | 100 | 100 | 100 |
| Syncrude | | | |
| Equity Securities | 60 | 60 | 60 |
| Debt Securities | 40 | 40 | 40 |
| Total | 100 | 100 | 100 |

i) The fair value of Nexen's defined benefit pension plan assets at December 31, 2011 by asset category are as follows:

| | Fair Value Measurements at December 31, 2011 | | | |
|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Observable Inputs (Level 2 | Significant Unobservable Inputs (Level 3) | Total |
| Asset Category | | | | |
| Cash | 2 | – | – | 2 |

| | | | | |
|---|---|---|---|---|
| Pooled Funds | | | | |
| Canadian Fixed Income | – | 114 | – | 114 |
| Canadian Equity | – | 80 | – | 80 |
| Foreign Equity | – | 132 | – | 132 |
| | | | | |
| Total | 2 | 326 | – | 328 |

ii)The fair value of Nexen's defined benefit pension plan assets at December 31, 2010 by asset category are as follows:

| | Fair Value Measurements at December 31, 2010 | | | |
|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total |
| Asset Category | | | | |
| Cash | 3 | – | – | 3 |
| Pooled Funds | | | | |
| Canadian Fixed Income | – | 105 | – | 105 |
| Canadian Equity | – | 78 | – | 78 |
| Foreign Equity | – | 126 | – | 126 |
| Total | 3 | 309 | – | 312 |

iii)The fair value of Syncrude's defined benefit pension plan assets at December 31, 2011 by asset category are as follows:

| | Fair Value Measurements at December 31, 2011 | | | |
|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total |
| Asset Category | | | | |
| Cash | 1 | – | – | 1 |
| Pooled Funds | | | | |
| Canadian Fixed Income | – | 38 | – | 38 |
| Canadian Equity | – | 25 | – | 25 |
| Foreign Equity | – | 33 | – | 33 |
| Other Types of Investments | | | | |
| Other | – | – | 1 | 1 |
| Total | 1 | 96 | 1 | 98 |

iv)The fair value of Syncrude's defined benefit pension plan assets at December 31, 2010 by asset category are as follows:

| | Fair Value Measurements at December 31, 2010 | | | |
|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total |
| Asset Category | | | | |
| Cash | 1 | – | – | 1 |
| Pooled Funds | | | | |
| Canadian Fixed Income | – | 32 | – | 32 |
| Canadian Equity | – | 22 | – | 22 |
| Foreign Equity | – | 31 | – | 31 |
| Other Types of Investments | | | | |
| Other | – | – | 1 | 1 |
| Total | 1 | 85 | 1 | 87 |

(C) DEFINED CONTRIBUTION PENSION PLANS

Under these plans, pension benefits are based on plan contributions. During 2011, Canadian pension expense for these plans was $7 million (2010 – $7 million). During 2011, US pension expense for these plans was $6 million (2010 – $6 million) and UK pension expense for these plans was $6 million (2010 – $6 million).

(D) POST-RETIREMENT BENEFITS

Nexen provides certain post-retirement benefits, including group life and supplemental health insurance, to eligible employees and their dependents. The present value of Nexen employees' future post-retirement benefits at December 31, 2011 was $18 million (2010 – $15 million).

(E) EMPLOYER FUNDING CONTRIBUTIONS AND BENEFIT PAYMENTS

Canadian regulators have prescribed funding requirements for our defined benefit plans. Our funding contributions over the last three years have met these requirements and also included additional discretionary contributions permitted by law to ensure the plans are adequately funded in light of potential future changes in assumptions. For our defined contribution pension plans, we make contributions on behalf of our employees and no further obligation exists. Our funding contributions for our defined benefit plans are:

| | Expected 2012 | 2011 | 2010 |
|---|---|---|---|

| | | | |
|---|---|---|---|
| Nexen | 20 | 29 | 33 |
| Syncrude | 13 | 13 | 14 |
| | | | |
| Total Defined Benefit Contribution | 33 | 42 | 47 |

Our most recent funding valuation was prepared as of June 30, 2011. Our next funding valuation is required by June 30, 2014. Syncrude’s most recent funding valuation was prepared as of December 31, 2010, and their next funding valuation is required by December 31, 2013.

Our total benefit payments in 2011 were $18 million for Nexen (2010 – $19 million). Our share of Syncrude's total benefit payments in 2011 was $6 million (2010 – $6 million).

## 17. RELATED PARTY DISCLOSURES

### (A) MAJOR SUBSIDIARIES

The Consolidated Financial Statements include the financial statements of Nexen Inc. and our subsidiaries as at December 31, 2011. The following is a list of the major subsidiaries of our operations. Transactions between subsidiaries are eliminated on consolidation. Nexen did not have any material related party transactions with entities outside the consolidated group in the years ended December 31, 2011 and 2010.

| Major Subsidiaries | Jurisdiction of Incorporation | Principal Activities | Ownership |
|---|---|---|---|
| Nexen Petroleum UK Limited | England and Wales | Oil & Gas | 100% |
| Nexen Petroleum Nigeria Limited | Nigeria | Oil & Gas | 100% |
| Nexen Petroleum Offshore USA Inc. | Delaware | Oil & Gas | 100% |
| Nexen Marketing | Alberta | Marketing | 100% |
| Canadian Nexen Petroleum Yemen | Yemen | Oil & Gas | 100% |
| Nexen Oil Sands Partnership | Alberta | Oil & Gas | 100% |

### (B) KEY MANAGEMENT PERSONNEL COMPENSATION

Key management personnel compensation includes all compensation paid to executive management and members of the board of directors of Nexen Inc. during the year.

| | 2011 | 2010 |
|---|---|---|
| Short-Term Benefits1 | 9 | 9 |
| Post Employment Benefits2 | 3 | 4 |
| Share-Based Compensation3 | (11) | 2 |
| Total Compensation | 1 | 15 |

1Includes employee salary and director's fees, non-equity incentive plan compensation and other short-term compensation.

2Represents the pension current service cost, plus changes in compensation in excess of managerial assumptions, less required member contributions to the plan.

3Stock-based compensation computed for executive management and the board of directors as described in Note 18 and represents change in fair value of outstanding awards.

## 18. EQUITY

### (A) AUTHORIZED CAPITAL

Authorized share capital consists of an unlimited number of common shares of no par value and an unlimited number of Class A preferred shares of no par value, issuable in series. At December 31, 2011, there were 527,892,635 common shares outstanding (December 31, 2010 – 525,706,403 shares; and January 1, 2010 – 522,915,843 shares). There were no preferred shares issued and outstanding as at December 31, 2011 (December 31, 2010 – nil; and January 1, 2010 – nil). The rights, privileges, restrictions and conditions attached to common shares include a vote at all meetings of shareholders they are invited to, the receipt of any dividend declared by the board of directors on the common shares, and receipt of all remaining property of Nexen upon dissolution.

(B) ISSUED COMMON SHARES AND DIVIDENDS

Dividends per common share for the year ended December 31, 2011 were $0.20 per common share (2010 – $0.20 per common share). Dividends paid to holders of common shares have been designated as “eligible dividends” for Canadian tax purposes.

On February 15, 2012, the board of directors declared a quarterly dividend of $0.05 per common share, payable April 1, 2012 to the shareholders of record on March 9, 2012.

| (thousands of shares) | 2011 | 2010 |
|---|---|---|
| Issued Common Shares, Beginning of Year | 525,706 | 522,916 |
| Issue of Common Shares for Cash Exercise of Tandem Options | 59 | 527 |
| Dividend Reinvestment Plan | 1,542 | 1,654 |
| Employee Flow-Through Shares | 586 | 609 |
| End of Year | 527,893 | 525,706 |
| (Cdn$ millions) | | |
| Cash Consideration | | |
| Exercise of Tandem Options | 1 | 5 |
| Dividend Reinvestment Plan | 30 | 35 |
| Employee Flow-Through Shares | 15 | 15 |
| Total | 46 | 55 |

During the year, 1,541,707 common shares were issued under the Dividend Reinvestment Plan and a balance of 3,079,464 common shares (2010 – 621,171) was reserved for issuance at December 31, 2011.

(C) TANDEM OPTIONS

Tandem and performance tandem options to purchase common shares are awarded to officers and employees. Each option permits the holder the right to either purchase one Nexen common share at the exercise price or receive a cash payment equal to the excess of market price over the exercise price. The following tandem and performance tandem options have been granted:

| | 2011 | | 2010 | |
|---|---|---|---|---|
| (thousands of shares) | Options (thousands) | Weighted Average Exercise Price ($/option) | Options (thousands) | Weighted Average Exercise Price ($/option) |
| Outstanding TOPs, Beginning of Year | 18,435 | 25 | 23,130 | 25 |
| Granted | 1,582 | 17 | 4,615 1 | 22 |
| Exercised for Stock | (59) | 16 | (527) | 9 |
| Surrendered for Cash | (394) | 20 | (2,191) | 11 |
| Cancelled | (1,248) | 25 | (2,704) | 28 |
| Expired | (3,462) | 31 | (3,888) | 27 |
| | | | | |
| End of Year | 14,854 | 23 | 18,435 | 25 |
| | | | | |
| TOPs Exercisable at End of Year | 8,878 | 24 | 9,949 | 27 |
| Weighted Average Share Price During Year | 20.80 | | 22.48 | |

1 Approximately 29% of options granted in 2010 contain performance vesting conditions. No options granted in 2011 contain these conditions as those eligible were granted Performance Share Units (PSU).

The range of exercise prices of options outstanding at December 31, 2011 is as follows:

| | Outstanding Tandem and Performance Tandem Options | | |
|---|---|---|---|
| | Number of Options (thousands) | Weighted Average Exercise Price ($/option) | Weighted Average Years to Expiry (years) |
| $15.00 to $19.99 | 3,765 | 18 | 3 |
| $20.00 to $24.99 | 8,405 | 23 | 3 |
| $25.00 to $29.99 | 2,624 | 28 | 1 |
| $30.00 to $34.99 | 35 | 31 | – |

| | | | |
|---|---|---|---|
| $35.00 to $39.99 | 20 | 36 | – |
| $40.00 to $44.99 | 5 | 40 | 1 |
| | | | |
| Total | 14,854 | | |

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

Fair values and associated details for tandem and performance tandem options granted during the year:

| | 2011 | | 2010 | |
|---|---|---|---|---|
| Option Pricing Model Used for TOPs | Black-Scholes1 | | Black-Scholes1 | |
| Weighted Average Fair Value ($/option) | 3.86 | | 8.542 | |
| Expected Volatility | 40 | % | 56 | % |
| Weighted-Average Expected Life (years) | 3.14 | | 3.18 | |
| Expected Annual Dividends per Common Share ($/share) | 0.20 | | 0.20 | |
| Risk-Free Interest Rate | 1.21 | % | 1.83 | % |
| Expected Annual Forfeiture Rate | 4 | % | 4 | % |

1The Monte-Carlo pricing model is used for the performance component of certain instruments. The assumptions used in this model do not differ significantly from those for non-performance TOPs.

2The weighted average fair value of performance tandem options granted in 2010 was $8.17 per option at December 31, 2010.

These assumptions are based on multiple factors, including: i) historical exercise patterns of employees in relatively homogenous groups with respect to exercise and post-vesting employment termination behaviors; ii) expected future exercising patterns for those same homogenous groups; iii) the implied volatility of our stock price (based on the prior three years historic volatility); iv) our expected future dividend levels; and v) the interest rate for Government of Canada bonds.

The total expense recovery arising from tandem options for the year ended December 31, 2011 was $39 million (2010 – $28 million). The total carrying value of liabilities arising from tandem options at December 31, 2011 amounted to $15 million (2010 – $56 million). The total intrinsic value of all vested tandem options at December 31, 2011 amounted to nil (2010 – $11 million).

(D) STOCK APPRECIATION RIGHTS

STARs and performance STARs are awarded to eligible employees. They permit the holder to receive a cash payment equal to the excess of the market price of the common shares over the exercise price of the right. The following STARs and performance STARs have been granted:

| | 2011 | | | 2010 | | |
|---|---|---|---|---|---|---|
| (thousands of shares) | STARs (thousands) | | Weighted Average Exercise Price ($/STAR) | STARs (thousands) | | Weighted Average Exercise Price ($/STAR) |
| Outstanding STARs, Beginning of Year | 18,993 | | 25 | 19,480 | | 25 |
| Granted | 377 | | 18 | 3,3541 | | 22 |
| Exercised for Cash | (578 | ) | 18 | (444 | ) | 16 |
| Cancelled | (1,163 | ) | 24 | (1,806 | ) | 27 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Expired | (3,222 | ) | 31 | (1,591 | ) | 27 |
| | | | | | | |
| End of Year | 14,407 | | 23 | 18,993 | | 25 |
| | | | | | | |
| STARs Exercisable at End of Year | 10,512 | | 24 | 10,938 | | 26 |
| Weighted Average Share Price During Year | 20.80 | | | 22.48 | | |

II-66

1 Approximately 9% of STARs granted in 2010 contain performance vesting conditions. No STARs granted in 2011 contain these conditions as those eligible were granted PSUs.

The range of exercise prices of STARs outstanding at December 31, 2011 is as follows:

| | Outstanding STARs and Performance STARs | | |
|---|---|---|---|
| | Number of Options (thousands) | Weighted Average Exercise Price ($/STAR) | Weighted Average Years to Expiry (years) |
| $10.00 to $14.99 | 17 | 14 | 2 |
| $15.00 to $19.99 | 3,675 | 18 | 2 |
| $20.00 to $24.99 | 7,541 | 24 | 3 |
| $25.00 to $29.99 | 3,001 | 28 | 1 |
| $30.00 to $34.99 | 112 | 33 | - |
| $35.00 to $39.99 | 60 | 36 | - |
| $40.00 to $44.99 | 1 | 40 | 1 |
| Total | 14,407 | | |

Fair values and associated details for STARs and performance STARs granted during the period:

| | 2011 | | 2010 | |
|---|---|---|---|---|
| Option Pricing Model Used for STARs | Black-Scholes1 | | Black-Scholes1 | |
| Weighted Average Fair Value ($/STAR) | 3.48 | | 8.34 | 2 |
| Expected Volatility | 40 | % | 56 | % |
| Weighted-Average Expected Life (years) | 2.84 | | 2.98 | |
| Expected Annual Dividends per Common Share ($/share) | 0.20 | | 0.20 | |
| Risk-Free Interest Rate | 1.21 | % | 1.83 | % |
| Expected Annual Forfeiture Rate | 5 | % | 4-5 | % |

1 The Monte-Carlo pricing model is used for the performance component of certain instruments. The assumptions used in this model do not differ significantly from those for non-performance STARs.

2 The weighted average fair value of performance STARs granted in 2010 was $8.17 per performance STAR at December 31, 2010.

These assumptions are based on multiple factors, including: i) historical exercise patterns of employees in relatively homogenous groups with respect to exercise and post-vesting employment termination behaviors; ii) expected future exercising patterns for those same homogenous groups; iii) the implied volatility of our stock price (based on the prior three years historic volatility); iv) our expected future dividend levels; and v) the interest rate for Government of Canada bonds.

The total recovery arising from STARs for the year ended December 31, 2011 was $45 million (2010 - expense $1 million). The total carrying value of liabilities arising from STARs at December 31, 2011 amounted to $12 million (2010 – $61 million). The total intrinsic value of all vested STARs at December 31, 2011 amounted to nil (2010 – $17 million).

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

(E) SHARE UNIT PLANS

Restricted Share Units (RSUs) are awarded to eligible employees and permit the holder to receive a cash payment equal to the market value of the stock on the vesting date. Performance Share Units (PSUs) are RSUs with a performance-vesting condition. Deferred Share Units (DSUs) are awarded to directors. The following RSUs, PSUs and DSUs have been granted:

| (thousands of units) | RSU | PSU | DSU |
|---|---|---|---|
| Outstanding January 1, 2010 | - | - | 489 |
| Granted | 925 | - | 87 |
| Outstanding December 31, 2010 | 925 | - | 576 |
| Granted | 1,458 | 390 | 143 |
| Redeemed for Cash | (302) | - | - |
| Cancelled | (56) | - | - |
| Outstanding December 31, 2011 | 2,025 | 390 | 719 |
| Weighted Average Fair Value per Unit ($/unit) | 16.21 | 9.59 | 16.21 |
| Liability ($/millions) | 7 | - | 12 |
| Weighted Average Remaining Time to Expiry (years) | 1.7 | 1.8 | |

For the year ended December 31, 2011, we recognized compensation expense related to RSUs and PSUs in the amount of $10 million (2010 - $2 million). RSUs and PSUs are paid immediately once they vest. We recognized a compensation recovery related to DSUs in the amount of $1 million (2010 - expense $1 million).

19. COMMITMENTS, CONTINGENCIES AND GUARANTEES

We assume various contractual obligations and commitments in the normal course of our operations. Our operating leases, transportation, processing and storage commitments, finance leases, and drilling rig commitments as at December 31, 2011 are comprised of the following:

| | 2012 | 2013 | 2014 | 2015 | 2016 | Thereafter |
|---|---|---|---|---|---|---|
| Operating Leases | 66 | 64 | 46 | 26 | 25 | 89 |
| Transportation, Processing and Storage Commitments | 99 | 84 | 69 | 42 | 38 | 129 |
| Drilling Rig Commitments | 305 [1] | 208 | 16 | - | - | - |
| Finance Leases | 4 | 4 | 4 | 4 | 4 | 62 |

1Total drilling rig commitments are disclosed net of $102 million of subleases.

During 2011, total rental expense under operating leases was $53 million (2010 - $62 million).

We have a number of lawsuits and claims pending, including tax audits, the ultimate results of which cannot be ascertained at this time. We record costs as they are incurred or become determinable.

From time to time, we enter into contracts that require us to indemnify parties against certain types of possible third-party claims, particularly when these contracts relate to divestiture transactions. On occasion, we may provide routine indemnifications. The terms of such obligations vary and, generally, a maximum is not explicitly stated. Because the obligations in these agreements are often not explicitly stated, the overall maximum of the obligations cannot be reasonably estimated. Historically, we have not been obligated to make significant payments for these obligations. We believe that payments, if any, related to existing indemnities would not have a material adverse effect on our liquidity, financial condition or results of operations.

## 20.MARKETING AND OTHER INCOME

| | 2011 | 2010 |
|---|---|---|
| Marketing Revenue, Net | 195 | 337 |
| Insurance Proceeds | 26 | - |
| Change in Fair Value of Crude Oil Put Options | (23) | (41) |
| Foreign Exchange Gains (Losses) | 36 | (38) |
| Other | 61 | 65 |
| Total | 295 | 323 |

## 21. INCOME TAXES

### (A) PROVISION FOR (RECOVERY OF) INCOME TAXES

| | 2011 | 2010 |
|---|---|---|
| Current Tax | | |
| Charge for the Year | 1,584 | 1,125 |
| Deferred Tax | | |
| Temporary Differences in the Current Year | (526) | (449) |
| Impact of Changes in Tax Rates and Laws | 270 | - |
| Total Income Tax Expense Recognized in Net Income | 1,328 | 676 |

### (B) DEFERRED INCOME TAX

| | Consolidated Statement of Income | | Consolidated Balance Sheet | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| Property, Plant and Equipment and Other | (25) | (91) | 3,027 | 2,850 |
| Tax Losses and Credits1 | (215) | (347) | (1,985) | (1,669) |
| Foreign-Denominated Debt | (16) | (11) | 108 | 146 |
| Net Deferred Income Tax | (256) | (449) | 1,150 | 1,327 |

1 Deferred tax assets have been recognized as it is probable there will be sufficient future taxable profits.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

| Net Deferred Income Tax Liability | 2011 | 2010 |
|---|---|---|
| Balance, Beginning of Year | 1,327 | 1,603 |
| Annual Recovery in Net Income | (256) | (449) |
| Provision (Recovery) in Other Comprehensive Income | (35) | 21 |
| Provision (Recovery) in Equity | 18 | 4 |
| Discontinued Operations | 51 | 224 |
| Effects of changes in Foreign Exchange Rates | 35 | (61) |
| Other | 10 | (15) |
| Balance, End of Year | 1,150 | 1,327 |

(C) RECONCILIATION OF EFFECTIVE TAX RATE TO THE CANADIAN STATUTORY TAX RATE

| | 2011 | 2010 |
|---|---|---|
| Income before Provision for Income Taxes | 1,723 | 1,130 |
| Provision for Income Taxes Computed at the Canadian Statutory Rate | 431 | 284 |
| Add (Deduct) the Tax Effect of: | | |
| Foreign Tax Rate Differential | 701 | 355 |
| Effect of Changes in Tax Rates1 | 270 | – |
| Lower Tax Rates on Capital Losses | 16 | 11 |
| Recognition of Previously Unrecognized Tax Assets | (70) | - |
| Stock-Based Compensation | (10) | 13 |
| Non-Deductible Expenses and Other | (10) | 13 |
| Provision for Income Taxes | 1,328 | 676 |
| Effective Tax Rate | 77% | 60% |

1Effective March 24, 2011, the UK government substantively enacted an increase to the supplementary charge tax rate on our North Sea oil and gas activities of 12%, which increased the statutory oil and gas income tax rate to 62%. This rate change increased our deferred income tax liabilities, resulting in a one-time charge of $270 million to deferred tax expense.

(D)UNRECOGNIZED DEFERRED TAX ASSETS

At December 31, 2011, we had unrecognized deferred tax assets related to unused tax credits totaling $977 million (2010 - $724 million). This includes $871 million (2010 - $604 million) of Nigeria investment tax credits with no fixed expiry date. The remainder expires between 2015 and 2031.

We had no significant unrecognized deferred tax assets related to tax losses or other deductible temporary differences as at December 31, 2011.

(E) INCOME TAX AUDITS

Nexen's income tax filings are subject to audit by taxation authorities in numerous jurisdictions. There are audits in progress and items under review, some of which may increase our tax liability. In addition, we have filed appeals and have disputed certain issues. While the results of these items cannot be ascertained at this time, we believe we have an adequate provision for income taxes based on available information.

## 22. EARNINGS PER COMMON SHARE

We calculate basic earnings per common share using net income attributable to Nexen Inc. shareholders divided by the weighted-average number of common shares outstanding. We calculate diluted earnings per common share in the same manner as basic, except we adjust basic earnings for the potential conversion of the subordinated debentures and potential exercise of outstanding tandem options for shares, and use the weighted-average number of diluted common shares outstanding in the denominator.

| | 2011 | 2010 |
|---|---|---|
| ($Cdn millions) | | |
| Net Income Attributable to Nexen Inc. Shareholders, Basic | 697 | 1,127 |
| Potential Tandem Options Exercises | (40) | (8) |
| Potential Conversion of Subordinated Debentures | 25 | 26 |
| Net Income Attributable to Nexen Inc. Shareholders, Diluted | 682 | 1,145 |
| | | |
| (millions of shares) | | |
| Weighted Average Number of Common Shares Outstanding, Basic | 527.2 | 524.7 |
| Shares Issuable Pursuant to Tandem Options | 2.5 | 4.0 |
| Shares Notionally Purchased from Proceeds of Tandem Options | (2.3) | (2.7) |
| Common Shares Issuable Pursuant to Potential Conversion of Subordinated Debentures | 21.5 | 21.0 |
| Weighted Average Number of Common Shares Outstanding, Diluted | 548.9 | 547.0 |

In calculating the weighted-average number of diluted common shares outstanding and related earnings adjustments for the year ended December 31, 2011, we excluded 14,596,971 tandem options (2010 - 17,118,617) because their exercise price was greater than the average common share market price in the year. In 2011 and 2010, outstanding tandem options and potential conversion of subordinated debentures were the only potential dilutive instruments.

## 23. DISPOSITIONS

### (A) DISCONTINUED OPERATIONS

In February 2011, we completed the sale of our 62.7% investment in Canexus, which operates a chemicals business, for net proceeds of $458 million and we realized a gain on disposition of $348 million in the first quarter. In the fourth quarter of 2010, we received board approval to sell our interest in Canexus and classified the assets and liabilities as held for sale at December 31, 2010. The gain on sale and results of our chemicals business have been presented as discontinued operations.

In July 2010, we completed the sale of our heavy oil properties in Canada. We received proceeds of $939 million, net of closing adjustments and realized a gain on disposition of $828 million in the third quarter of 2010. The gain on sale and results of operations of these properties have been presented as discontinued operations.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

| | Year Ended December 31 | | | |
|---|---|---|---|---|
| | 2011 | | 2010 | |
| | Chemicals | Canada | Chemicals | Total |
| Revenues and Other Income | | | | |
| Net Sales | 42 | 138 | 456 | 594 |
| Other | (1 ) | - | 25 | 25 |
| Gain on Disposition | 348 | 828 | - | 828 |
| | 389 | 966 | 481 | 1,447 |
| Expenses | | | | |
| Operating | 25 | 50 | 308 | 358 |
| Depreciation, Depletion, Amortization and Impairment | 4 | 20 | 35 | 55 |
| Transportation and Other | 2 | 2 | 60 | 62 |
| General and Administrative | 2 | 10 | 38 | 48 |
| Finance | 2 | 3 | 19 | 22 |
| | 35 | 85 | 460 | 545 |
| Income before Provision for Income Taxes | 354 | 881 | 21 | 902 |
| Less: Provision for Deferred Income Taxes | 51 | 220 | 4 | 224 |
| Income before Non-Controlling Interests | 303 | 661 | 17 | 678 |
| Less: Non-Controlling Interests | 1 | - | 5 | 5 |
| Net Income from Discontinued Operations, Net of Tax | 302 | 661 | 12 | 673 |
| | | | | |
| Earnings Per Common Share | | | | |
| Basic | 0.57 | | | 1.28 |
| Diluted | 0.55 | | | 1.23 |

The following table provides the assets and liabilities that are associated with our chemicals business at December 31, 2010 and January 1, 2010. There were no assets or liabilities related to our chemical operations at December 31, 2011.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

| | December 31 2010 | January 1 2010 |
|---|---|---|
| Cash and Cash Equivalents | 3 | 14 |
| Accounts Receivable | 48 | 54 |
| Inventories and Supplies | 35 | 33 |
| Other Current Assets | 1 | 3 |
| Property, Plant and Equipment, Net of Accumulated DD&A | 629 | 535 |
| Deferred Income Tax Assets | 7 | 4 |
| Other Long-Term Assets | 6 | 11 |
| Assets | 729[1] | 654 |
| | | |
| Accounts Payable and Accrued Liabilities | 59 | 64 |
| Accrued Interest Payable | 3 | - |
| Long-Term Debt | 414 | 335 |
| Deferred Income Tax Liability | 15 | 11 |
| Asset Retirement Obligations | 73 | 74 |
| Other Long-Term Liabilities | 18 | 16 |
| Liabilities | 582[1] | 500 |
| Equity – Canexus Non-Controlling Interest | 48 | 33 |

1 Included in assets and liabilities held for sale at December 31, 2010. Amounts related to prior periods have not been reclassified.

(B) ASSET DISPOSITIONS

UK North Sea

During the fourth quarter of 2011, we sold our non-operated working interest in the Duart field for proceeds of $38 million. The sale closed in December 2011 and we recognized a gain on sale of $38 million in the fourth quarter of 2011.

UK Undeveloped Leases

During the fourth quarter of 2010, we sold non-core lands in the UK North Sea for proceeds of $17 million. We had no plans to develop these leases. We recognized a gain on disposition of $17 million in the fourth quarter of 2010.

North Dakota/Montana Crude Oil Marketing

During the fourth quarter of 2010, we sold our oil lease gathering, pipelines and storage assets in North Dakota and Montana for proceeds of $201 million. The sale closed in December 2010 and we recognized a gain on disposition of $121 million in the fourth quarter of 2010.

Natural Gas Energy Marketing

During the third quarter of 2010, we sold our North American natural gas marketing operations. The sale, which generated proceeds of $11 million, closed in the third quarter of 2010 and we recognized a non-cash loss of $259 million, primarily related to the transfer of long-term physical transportation commitments. On closing, the purchaser acquired our North American natural gas storage and transportation commitments, natural gas inventory, and related financial and physical derivative positions.

Canadian Undeveloped Oil Sand Leases

During the second quarter of 2010, we sold non-core lands in the Athabasca region for proceeds of $81 million. We had no plans to develop these lands for at least a decade. We recognized a gain on sale of $80 million in the second quarter of 2010.

European Gas and Power Marketing

During the first quarter of 2010, we sold our European Gas and Power marketing business for cash proceeds of $15 million. There was no gain or loss on the disposition.

## 24. CASH FLOWS

### (A) CHARGES AND CREDITS TO INCOME NOT INVOLVING CASH

| | 2011 | 2010 |
|---|---|---|
| Depreciation, Depletion, Amortization and Impairment | 1,913 | 1,628 |
| Stock-Based Compensation | (85) | (52) |
| Loss on Debt Redemption and Repurchase | 91 | - |
| Net (Gain) Loss on Dispositions | (38) | 41 |
| Non-Cash Items Included in Discontinued Operations | (290) | (549) |
| Provision for Deferred Income Taxes | (256) | (449) |
| Foreign Exchange | (33) | 26 |
| Other | 33 | 82 |
| Total | 1,335 | 727 |

### (B)CHANGES IN NON-CASH WORKING CAPITAL

| | 2011 | 2010 |
|---|---|---|
| Accounts Receivable | (381) | 96 |
| Inventories and Supplies | 208 | (105) |
| Other Current Assets | 26 | 47 |
| Accounts Payable and Accrued Liabilities | 723 | 241 |
| Total | 576 | 279 |
| Relating to: | | |
| Operating Activities | 255 | 338 |
| Investing Activities | 321 | (59) |
| Total | 576 | 279 |

### (C) OTHER CASH FLOW INFORMATION

| | 2011 | 2010 |
|---|---|---|
| Interest Paid | 305 | 380 |

| | | |
|---|---|---|
| Income Taxes Paid | 1,448 | 951 |

## 25. OPERATING SEGMENTS AND RELATED INFORMATION

Effective in the first quarter of 2011, we amended our segment reporting to reflect changes in our business. In 2010, we disposed of non-core operations including heavy oil operations in Canada, chemicals and certain energy marketing businesses, and increased production at our Long Lake oil sands project. We report our segments to align with our key growth areas, specifically, Conventional Oil and Gas, Oil Sands and Shale Gas. Prior year results have been revised to reflect the presentation changes made in the current year.

Nexen has the following operating segments:

Conventional Oil and Gas: We explore for, develop and produce crude oil and natural gas from conventional sources around the world. Our operations are focused on the UK, North America (Canada and US) and other countries (offshore West Africa, Colombia and Yemen).

Oil Sands: We develop and produce synthetic crude oil from the Athabasca oil sands in northern Alberta. We produce bitumen using in situ and mining technologies and upgrade it into synthetic crude oil before ultimate sale. Our in situ activities are comprised of our operations at Long Lake and future development phases. Our mining activities are conducted through our 7.23% ownership of the Syncrude Joint Venture.

Shale Gas: We explore for and produce unconventional gas from shale formations in northeastern British Columbia. Production and results of operations are included within Conventional Oil and Gas until they become significant.

Corporate and Other includes energy marketing, unallocated items and the results of Canexus prior to its sale in February 2011. The results of Canexus have been presented as discontinued operations.

The accounting policies of our operating segments are the same as those described in Note 2. Net income (loss) of our operating segments excludes interest income, interest expense, unallocated corporate expenses and foreign exchange gains and losses. Identifiable assets are those used in the operations of the segments.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

Segmented Net Income for the Year Ended December 31, 2011

| | Conventional | | | Oil Sands | | Corporate and Other | Total |
|---|---|---|---|---|---|---|---|
| (Cdn$ millions) | United Kingdom | North America | Other Countries[1,2] | In Situ | Syncrude | | |
| Net Sales | 3,432 | 499 | 781 | 688 | 713 | 56 | 6,169 |
| Marketing and Other Income | 21 | 39 | 21 | – | 3 | 211 | 295 |
| | 3,453 | 538 | 802 | 688 | 716 | 267 | 6,464 |
| Less: Expenses | | | | | | | |
| Operating | 353 | 156 | 164 | 439 | 287 | 32 | 1,431 |
| Depreciation, Depletion, Amortization and Impairment | 631 | 708[3] | 76 | 384[4] | 60 | 54 | 1,913 |
| Transportation and Other | 7 | 35 | 28 | 220 | 23 | 112 | 425 |
| General and Administrative | (8) | 74 | 31 | 19 | 1 | 183 | 300 |
| Exploration | 84 | 148 | 134[5] | 2 | – | – | 368 |
| Finance | 17 | 16 | 2 | 3 | 6 | 207 | 251 |
| Net Loss on Debt Redemption | – | – | – | – | – | 91 | 91 |
| Net Gain from Dispositions | (38) | – | – | – | – | – | (38) |
| Income (Loss) from Continuing Operations before Income Taxes | 2,407 | (599) | 367 | (379) | 339 | (412) | 1,723 |
| Less: Provision for (Recovery of) Income Taxes | 1,697 | (164) | 68 | (95) | 84 | (262) | 1,328 |
| Income (Loss) from Continuing Operations | 710 | (435) | 299 | (284) | 255 | (150) | 395 |
| Add: Net Income from Discontinued Operations | – | – | – | – | – | 302 | 302 |
| Net Income (Loss) | 710 | (435) | 299 | (284) | 255 | 152 | 697 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Capital Expenditures | 583 | 694 | 718[6] | 397 | 124 | 59 | 2,575 |

1 Includes results of operations in Yemen and Colombia.
2 Includes Masila net sales of $588 million and net income of $161 million.
3 Includes non-cash impairment charges of $322 million in Canada and the US.
4 Includes non-cash expenses of $253 million related to previously capitalized engineering and design costs.
5 Includes exploration activities primarily in Nigeria, Norway, Colombia and Poland.
6 Includes capital expenditures in Nigeria of $542 million.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

Segmented Net Income for the Year Ended December 31, 2010

| | Conventional | | | Oil Sands | | Corporate and Other | Total |
|---|---|---|---|---|---|---|---|
| (Cdn$ millions) | United Kingdom | North America | Other Countries | In Situ | Syncrude | | |
| Net Sales | 3,115 | 569 | 750 | 443 | 580 | 39 | 5,496 |
| Marketing and Other Income | 17 | 3 | 16 | – | 5 | 282 | 323 |
| | 3,132 | 572 | 766 | 443 | 585 | 321 | 5,819 |
| Less: Expenses | | | | | | | |
| Operating | 337 | 166 | 163 | 373 | 265 | 32 | 1,336 |
| Depreciation, Depletion, Amortization and Impairment | 783 | 519[3] | 120 | 94 | 53 | 59 | 1,628 |
| Transportation and Other | 2 | 22 | 27 | 181 | 21 | 313 | 566 |
| General and Administrative | 22 | 90 | 28 | 14 | 1 | 273 | 428 |
| Exploration | 67 | 156 | 104[4] | 1 | – | – | 328 |
| Finance | 17 | 17 | 1 | 3 | 4 | 320 | 362 |
| Net (Gain) Loss from Dispositions | (17)[5] | – | – | (80)[6] | – | 138[7] | 41 |
| Income (Loss) from Continuing Operations before Income Taxes | 1,921 | (398) | 323 | (143) | 241 | (814) | 1,130 |
| Less: Provision for (Recovery of) Income Taxes | 960 | (119) | 64 | (36) | 60 | (253) | 676 |
| Income (Loss) from Continuing Operations | 961 | (279) | 259 | (107) | 181 | (561) | 454 |
| Add: Net Income from Discontinued Operations | – | 635 | – | – | – | 38 | 673 |
| Net Income (Loss) | 961 | 356 | 259 | (107) | 181 | (523) | 1,127 |
| Capital Expenditures | 699 | 815 | 652[8] | 228 | 119 | 211 | 2,724 |

1 Includes results of operations in Yemen and Colombia.
2 Includes Masila net sales of $570 million and net income of $156 million.
3 Includes non-cash impairment charges of $139 million in Canada and the US.
4 Includes exploration activities primarily in Yemen, Nigeria, Norway and Colombia
5 Gain on disposition of UK undeveloped lease
6 Gain on disposition of non-core lands in the Athabasca region.
7 Net loss on disposition of Natural Gas Energy Marketing Business and North Dakota/Montana Crude Oil Marketing assets.
8 Includes capital expenditures in Nigeria of $495 million.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

Segmented Assets as at December 31, 2011

| (Cdn$ millions) | Conventional United Kingdom | North America | | Other Countries | | Oil Sands In Situ | | Syncrude | Corporate and Other | | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Assets | 4,817 | 3,403 | | 2,138 | | 5,881 | | 1,423 | 2,406 | 1 | 20,068 |
| Property, Plant and Equipment Cost | 7,103 | 7,256 | | 2,566 | | 5,915 | | 1,733 | 649 | | 25,222 |
| Less: Accumulated DD&A | 3,707 | 4,299 | | 648 | | 205 | | 411 | 381 | | 9,651 |
| Net Book Value | 3,396 | 2,957 | 2 | 1,918 | 3 | 5,710 | 4 | 1,322 | 268 | | 15,571 |

1 Includes cash of $453 million, and Energy Marketing accounts receivable and inventory of $1,449 million.
2 Includes capitalized costs of $1,293 million associated with our Canadian shale gas operations.
3 Includes $1,821 million related to our Usan development, offshore Nigeria.
4 Includes net book value of $5,050 million for Long Lake Phase 1 and $660 million for future phases of our in situ oil sands projects.

Segmented Assets as at December 31, 2010

| (Cdn$ millions) | Conventional United Kingdom | North America | | Other Countries | | Oil Sands In Situ | | Syncrude | Corporate and Other | | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Assets | 4,249 | 3,195 | | 1,646 | | 5,782 | | 1,259 | 3,516 | 1 | 19,647 |
| Property, Plant and Equipment Cost | 6,389 | 6,422 | | 3,700 | | 5,756 | | 1,519 | 596 | | 24,382 |
| Less: Accumulated DD&A | 3,055 | 3,597 | | 2,370 | | 91 | | 359 | 331 | | 9,803 |
| Net Book Value | 3,334 | 2,825 | 2 | 1,330 | 3 | 5,665 | 4 | 1,160 | 265 | | 14,579 |

1 Includes cash of $817 million, and Energy Marketing accounts receivable and inventory of $1,498 million and Chemicals assets of $729 million.
2 Includes capitalized costs of $938 million associated with our Canadian shale gas operations.
3 Includes $1,210 million related to our Usan development, offshore Nigeria.
4 Includes net book value of $4,865 million for Long Lake Phase 1 and $800 million for future phases of our in situ oil sands projects.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

Segmented Assets as at January 1, 2010

| (Cdn$ millions) | Conventional United Kingdom | North America | Other Countries | Oil Sands In Situ | Syncrude | Corporate and Other | Total |
|---|---|---|---|---|---|---|---|
| Total Assets | 4,840 | 3,146 | 1,320 | 5,616 | 1,165 | 4,868 [1] | 20,955 |
| Property, Plant and Equipment Cost | 5,884 | 7,464 | 3,344 | 5,523 | 1,390 | 1,702 | 25,307 |
| Less: Accumulated DD&A | 2,458 | 4,600 | 2,387 | 7 | 319 | 867 | 10,638 |
| Net Book Value | 3,426 | 2,864 [2] | 957 [3] | 5,516 [4] | 1,071 | 835 | 14,699 |

1 Includes cash of $1,016 million, Energy Marketing accounts receivable and inventory of $2,392 million and Chemicals assets of $654 million.
2 Includes capitalized costs of $477 million associated with our Canadian shale gas operations.
3 Includes $760 million related to our Usan development, offshore Nigeria.
4 Includes net book value of $4,776 million for Long Lake Phase 1 and $740 million for future phases of our in situ oil sands projects.

## 26.TRANSITION TO IFRS

For all periods up to and including the year ended December 31, 2010, we prepared our Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles (Canadian GAAP). As a publicly listed company in Canada, we are required to prepare consolidated financial statements in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) for all periods after January 1, 2011, including comparative historical information.

In accordance with transitional provisions, we prepared our opening balance sheet as at January 1, 2010 (the transition date) and 2010 comparative financial information using the accounting policies set out in Note 2. These consolidated financial statements for the year ended December 31, 2011 are the first annual financial statements that comply with IFRS by applying existing IFRS with an effective date of December 31, 2011 or earlier. This transition note explains the material adjustments we made to convert our financial statements to IFRS.

Elected Exemptions from Full Retrospective Application

In preparing these Consolidated Financial Statements in accordance with IFRS 1 First-time Adoption of International Financial Reporting Standards (IFRS 1), we applied the following optional exemptions from full retrospective application of IFRS.

### (I)BUSINESS COMBINATIONS

We applied the business combinations exemption to not apply IFRS 3 Business Combinations retrospectively to past business combinations. Accordingly, we have not restated business combinations that took place prior to the transition date.

(II)FAIR VALUE OR REVALUATION AS DEEMED COST

We elected to measure certain producing oil and gas properties at fair value as at the transition date and use that amount as its deemed cost in the opening IFRS balance sheet.

(III)CUMULATIVE TRANSLATION DIFFERENCES

We elected to set the cumulative translation account to nil at January 1, 2010. This exemption has been applied to all subsidiaries.

(IV)SHARE-BASED PAYMENT TRANSACTIONS

We elected to use the IFRS 1 exemption whereby the liabilities for share-based payments that settled prior to January 1, 2010 were not required to be retrospectively restated.

(V)EMPLOYEE BENEFITS

We elected to apply the exemption for employee benefits to recognize the accumulated unrecognized net actuarial loss in retained earnings at January 1, 2010. This exemption has been applied to all defined benefit pension plans.

(VI) ASSET RETIREMENT OBLIGATIONS

We applied the exemption from full retrospective application of our asset retirement obligations as permitted for first-time adoption of IFRS. As such, we re-measured ARO as at January 1, 2010. We estimated the amount to be included in the related asset by discounting the liability to the date when the obligation first arose using our best estimates of the historical risk-free discount rates applicable during the intervening period.

(VII)BORROWING COSTS

We applied an IFRS transitional exemption to prospectively capitalize borrowing costs only from the transition date. As a result, borrowing costs previously capitalized under Canadian GAAP were expensed to retained earnings.

Mandatory Exceptions to Retrospective Application

In preparing these Consolidated Financial Statements in accordance with IFRS 1, we were required to apply the following mandatory exceptions from full retrospective application of IFRS.

(I)HEDGE ACCOUNTING

Only hedging relationships that satisfied the hedge accounting criteria as of the transition date are reflected as hedges in our results under IFRS. Any derivatives not meeting the IAS 39 Financial Instruments: Recognition and Measurement criteria for hedge accounting were recorded as a non-hedging derivative financial instrument.

(II)ESTIMATES

Hindsight was not used to create or revise estimates and accordingly, our estimates previously made under Canadian GAAP are consistent with their application under IFRS.

Reconciliations of Canadian GAAP to IFRS

IFRS 1 requires the presentation of a reconciliation of shareholders' equity, net income, comprehensive income, and cash flows for prior periods. The transition from Canadian GAAP to IFRS had no material effect upon previously reported cash flows. The following represents the reconciliations from Canadian GAAP to IFRS for the respective periods for shareholders' equity, net income, and comprehensive income:

RECONCILIATION OF SHAREHOLDERS' EQUITY

| (Cdn$ millions) | Note | January 1 2010 | December 31 2010 |
|---|---|---|---|
| Shareholders' Equity under Canadian GAAP | | 7,646 | 8,791 |
| Differences Increasing (Decreasing) Reported Shareholders' Equity | | | |
| Borrowing Costs | (I) | (841) | (778) |
| Asset Retirement Obligations | (II) | (228) | (241) |
| Employee Benefits | (III) | (104) | (150) |
| Stock-Based Compensation | (IV) | (96) | (92) |
| Property, Plant & Equipment | (V) | (124) | (90) |
| Foreign Exchange | (VI) | (11) | – |
| Long-Term Debt | (VII) | (9) | (28) |
| Income Taxes | (VIII) | 554 | 429 |
| Other | | – | (27) |
| Shareholders' Equity under IFRS | | 6,787 | 7,814 |

(I)BORROWING COSTS

We applied the IFRS 1 exemption to prospectively capitalize borrowing costs only from the transition date as described above.

(II)ASSET RETIREMENT OBLIGATIONS (ARO)

We applied the IFRS 1 exemption for asset retirement obligations and re-measured our ARO as at January 1, 2010 as described above.

(III)EMPLOYEE BENEFITS

We have chosen to include previously unrecognized actuarial gains and losses of our defined benefit pension plans on the balance sheet under IFRS. Under Canadian GAAP, we amortized actuarial gains and losses to income over the estimated average remaining service life, with disclosure of the unrecognized amount in the notes to the Consolidated Financial Statements. On January 1, 2010, we applied the IFRS 1 exemption to recognize the accumulated unrecognized net actuarial loss in retained earnings on transition to IFRS.

(IV)STOCK-BASED COMPENSATION (SBC)

Under Canadian GAAP, we recorded obligations for liability based stock compensation plans using the intrinsic-value method of accounting. IFRS requires that we record these SBC obligations at fair value and subsequently re-measure the obligation each reporting period. Our tandem option, stock appreciation rights and restricted share unit plans are considered liability-based stock compensation plans. On transition, we recorded the liability at fair value for unsettled awards.

## (V)PROPERTY, PLANT AND EQUIPMENT

### Impairment

Under Canadian GAAP, if indications of impairment exist and the asset's estimated undiscounted future cash flows were lower than its carrying amount, the carrying value was written down to fair value. Under IFRS, if indications of impairments exist, the asset's carrying value is immediately compared to its estimated recoverable amount, which could trigger additional impairment under IFRS. We elected to measure certain producing oil and gas properties at fair value as at the transition date and use that amount as its deemed cost in the opening IFRS balance sheet. As a result, oil and gas properties were written down to fair value of $460 million and resulted in an impairment expense of $91 million on transition.

### Componentization

Under Canadian GAAP, we depleted oil and gas capitalized costs using the unit-of-production method on a field-by-field basis and depreciated non-resource capitalized costs based on their estimated useful life. On adoption of IFRS, we reviewed our PP&E to identify each material component that has a significantly different useful life and as a result, adjustments to the accumulated depletion of certain assets resulted in an expense of $51 million on transition to IFRS.

### Major Maintenance

Under Canadian GAAP, operating expenses included major maintenance costs that were expensed as incurred. Under IFRS, $18 million was capitalized and depreciated separately until the next planned major maintenance project.

## (VI)FOREIGN EXCHANGE

### Foreign Currency Translation

We applied the first-time IFRS adoption exemption to reset our cumulative translation differences to nil on the transition date. Accumulated foreign exchange gains and losses of our foreign operations, net of foreign exchange translation gains and losses of long-term debt designated as hedges are included in retained earnings on the transition date. This one-time adjustment had no impact on shareholders' equity on transition.

### Change in Functional Currency

As a result of additional guidance under IFRS, our assessment of the functional currency of a subsidiary changed from Canadian dollars to US dollars to better reflect the economic environment in which it operates.

## (VII) LONG-TERM DEBT

### Canexus Convertible Debentures

Canexus unitholders have the ability to redeem fund units for cash pursuant to the terms of the trust indenture. Under IFRS, these convertible debentures are considered to be financial liabilities containing an embedded derivative. Under Canadian GAAP, the convertible debentures were considered to be compound instruments with an equity component.

Accordingly, the equity component and unamortized deferred transaction costs recorded under Canadian GAAP were derecognized on January 1, 2010 and charged to retained earnings. We elected to recognize the convertible debentures at fair value and to recognize changes in fair value in net income during the period of change.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

(VIII) INCOME TAXES

Recognition of Deferred Tax Credit

In 2008, we completed an internal reorganization and financing of our assets in the North Sea, which provided us with a one-time tax deduction in the UK. Canadian GAAP precluded us from recognizing the full estimated benefit of the tax deductions until the assets were recognized in net income either by a sale or depletion through use. As a result, we deferred the initial recognition of the benefit and were amortizing it to future income tax expense over the life of the underlying assets under Canadian GAAP. On adoption of IFRS, no such prohibition exists and we recognized the remaining deferred tax credit in retained earnings on transition to IFRS.

Exceptions

Under Canadian GAAP, deferred taxes were generally provided on all temporary differences. Conversely, IFRS does not recognize deferred taxes on temporary differences arising from the initial recognition of assets or liabilities in transactions that are not business combinations and that affect neither accounting nor taxable profit or loss.

RECONCILIATION OF NET INCOME

| (Cdn$ millions) | Note | Twelve Months Ended December 31 2010 |
|---|---|---|
| Net Income under Canadian GAAP | | 1,197 |
| Differences Increasing (Decreasing) Reported Net Income | | |
| Borrowing Costs | (I) | 63 |
| Asset Retirement Obligations | (II) | (13) |
| Stock-Based Compensation | (III) | 3 |
| Property, Plant & Equipment | (IV) | 34 |
| Long-Term Debt | (V) | (19) |
| Income Taxes | (VI) | (136) |
| Other | | (2) |
| Total Differences in Net Income | | (70) |
| | | |
| Net Income under IFRS | | 1,127 |

(I)BORROWING COSTS

We applied an IFRS transitional exemption to prospectively capitalize borrowing costs from the transition date. As a result, borrowing costs previously capitalized under Canadian GAAP were expensed to shareholders' equity. The reduced capitalized amounts decreased DD&A expense during 2010.

(II)ASSET RETIREMENT OBLIGATIONS (ARO)

Under Canadian GAAP, foreign exchange translation gains and losses arising from the revaluation of GBP-denominated asset retirement obligations were included in net income in the period in which they occurred. Under IFRS, these translation gains and losses are treated as a change in estimate and therefore increase or decrease PP&E with a corresponding impact on net income.

(III)STOCK-BASED COMPENSATION (SBC)

As described above, we record obligations for liability-based stock compensation plans at fair value each reporting period. Our tandem option, stock appreciation rights and restricted share unit plans are considered liability-based stock compensation plans. The changes in the SBC fair value in 2010 were recognized in net income.

(IV)PROPERTY, PLANT AND EQUIPMENT

Impairment

As described above, certain properties were impaired and written down to fair value on transition. These adjustments reduced IFRS DD&A expense during 2010 by immaterial amounts. In the last half of 2010, additional properties were impaired and written down to fair value. The impairment expense of $46 million reduced net income in the third and fourth quarters.

Major Maintenance Costs

As described above, Canadian GAAP operating expenses included major maintenance costs that were expensed as incurred. Under IFRS, these costs are capitalized and depreciated separately until the next planned major maintenance project. During 2010, we capitalized $18 million of maintenance costs under IFRS that were expensed as operating costs under Canadian GAAP.

Gain on Sale of Heavy Oil Properties

We completed the sale of our Canadian heavy oil properties in the third quarter of 2010. As the adoption of IFRS resulted in different carrying values of property, plant & equipment and asset retirement obligations prior to the sale, our gain on sale under IFRS was $47 million higher.

(V)LONG-TERM DEBT

Canexus Convertible Debentures

As described above, we elected to carry the Canexus convertible debentures at fair value under IFRS. The change in fair value during 2010 was included in net income.

(VI)INCOME TAXES

Recognition of Deferred Tax Credit

As described above, we amortized a deferred tax credit to income over the life of the underlying asset under Canadian GAAP. Under IFRS, the deferred tax credit was recognized in retained earnings on transition. Therefore, IFRS net income was lower by $117 million for the twelve months ended December 31, 2010.

Other

All other adjustments to IFRS net income were tax effected which increased deferred tax expense by $19 million for the twelve months ended December 31, 2010.

RECONCILIATION OF COMPREHENSIVE INCOME

Twelve Months

| (Cdn$ millions) | Note | Ended December 31 2010 |
|---|---|---|
| Comprehensive Income under Canadian GAAP | | 1,168 |
| Differences Increasing (Decreasing) Reported Comprehensive Income, Net of Income Taxes: | | |
| Differences in Net Income | | (70) |
| Foreign Currency Translation | (I) | (8) |
| Employee Benefits | (II) | (35) |
| Comprehensive Income under IFRS | | 1,055 |

(I)FOREIGN CURRENCY TRANSLATION

Transitional adjustments reflect the foreign currency exchange impact of the IFRS adjustments during the respective periods.

(II)EMPLOYEE BENEFITS

As described in Note 2, actuarial gains and losses are recognized directly in other comprehensive income in the period in which they occur. For the twelve months ended December 31, 2010, actuarial losses on our defined benefit plans reduced other comprehensive income by $35 million.

(3) The following is an extract of the audited financial statements of Nexen Group for the year ended 31 December 2010, which were prepared in accordance with Canadian GAAP, from the 2010 annual report and financial statements of Nexen Group. These financial statements were presented in C$ million dollars except for otherwise stated.

Nexen's 2010 annual report and financial statements are available free of charge, in read only, printable format on Nexen's website.

REPORT OF MANAGEMENT

February 16, 2011

To the Shareholders of Nexen Inc.

We are responsible for the preparation and fair presentation of the Consolidated Financial Statements, as well as the financial reporting process that gives rise to such Consolidated Financial Statements. This responsibility requires us to make significant accounting judgments and estimates. For example, we are required to choose accounting principles and methods that are appropriate to the company's circumstances, and we are required to make estimates and assumptions that affect amounts reported. Fulfilling this responsibility requires the preparation and presentation of our Consolidated Financial Statements in accordance with generally accepted accounting principles in Canada with a reconciliation to generally accepted accounting principles in the US.

We also have responsibility for the preparation and fair presentation of other financial information in this report and to ensure the consistency of this information with the financial statements.

We are responsible for developing and implementing internal controls over the financial reporting process. These controls are designed to provide reasonable assurance that relevant and reliable financial information is produced. To gather and control financial data, we have established accounting and reporting systems supported by internal controls over financial reporting and an internal audit program. We believe that our internal controls over financial reporting provide reasonable assurance that our assets are safeguarded against loss from unauthorized use or disposition, that receipts and expenditures of the company are made only in accordance with authorization of management and directors of the company and that our records are reliable for preparing our Consolidated Financial Statements and other financial information in accordance with applicable generally accepted accounting principles and in accordance with applicable securities rules and regulations. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

We have established disclosure controls and procedures, internal controls over financial reporting and corporate-wide policies to ensure that Nexen's consolidated financial position, results of operations and cash flows are presented fairly. Our disclosure controls and procedures are designed to ensure timely disclosure and communication of all material information required by regulators. We oversee, with assistance from our Disclosure Review Committee, these controls and procedures and all required regulatory disclosures.

To ensure the integrity of our financial statements, we carefully select and train qualified personnel. We also ensure our organizational structure provides appropriate delegation of authority and division of responsibilities. Our policies and procedures are communicated throughout the organization and include a written ethics and integrity policy that applies to all employees, including the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer or Controller.

Our Board of Directors is responsible for reviewing and approving the Consolidated Financial Statements and for overseeing management's performance of its financial reporting responsibilities. Their financial statement-related responsibilities are fulfilled mainly through the Audit and Conduct Review Committee (Audit Committee), with assistance from the Reserves Review Committee regarding the annual review of our crude oil and natural gas reserves, and the Finance Committee regarding the assessment and mitigation of financial risk. The Audit Committee is composed entirely of independent directors and includes five directors with financial expertise. The Audit Committee meets regularly with management, the internal auditors and the independent registered Chartered Accountants to review accounting policies, financial reporting and internal control issues and to ensure each party is properly discharging its responsibilities. The Audit Committee is responsible for the appointment and compensation of the independent registered Chartered Accountants and also considers their independence, reviews their fees and (subject to applicable securities laws) pre-approves their retention for any permitted non-audit services and their fee for such services. The internal auditors and independent registered Chartered Accountants have full and unlimited access to the Audit Committee, with and without the presence of management.

(signed) "Marvin F. Romanow
President and Chief Executive Officer

(signed) "Kevin J. Reinhart"
Executive Vice President and Chief Financial Officer

## MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Exchange Act Rules 13(a)-15(f)). Under the supervision and with the participation of our management, including our principal executive officer (CEO) and principal financial officer (CFO), we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control –Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, we concluded that our internal control over financial reporting is effective as of December 31, 2010. We have documented this assessment and made this assessment available to our independent registered Chartered Accountants. We recognize that all internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Deloitte & Touche LLP audited our Consolidated Financial Statements as stated in their report and has provided an attestation report on our internal control over financial reporting.

## REPORTS OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Nexen Inc.

We have audited the accompanying consolidated financial statements of Nexen Inc. and subsidiaries (the "Company"), which comprise the consolidated balance sheets as at December 31, 2010 and 2009, and the consolidated statements of income, cash flows, equity and comprehensive income for each of the years in the three year period ended December 31, 2010, and the notes to the consolidated financial statements.

### Management's Responsibility for the Consolidated Financial Statements

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

### Auditor's Responsibility

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

An audit involves performing procedures to obtain audit evidence 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 entity'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 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.

Opinion

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

Emphasis of Matter

We draw your attention to Note 1(U) to the consolidated financial statements which describe the adoption of the Financial Accounting Standards Board guidance for Oil and Gas Reserve Estimation and Disclosure, which is effective for years ended on or after December 31, 2009. Our opinion is not qualified in respect of this matter.

Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 16, 2011 expressed an unqualified opinion on the Company's internal control over financial reporting.

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants
Calgary, Canada

February 16, 2011

To the Board of Directors and Shareholders of Nexen Inc.

We have audited the internal control over financial reporting of Nexen Inc. and subsidiaries (the “Company”) as of December 31, 2010, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit.

We conducted our audit 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. Our audit included 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 considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company’s internal control over financial reporting is a process designed by, or under the supervision of, the company’s principal executive and principal financial officers, or persons performing similar functions, and effected by the company’s board of directors, management, and other personnel 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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2010, and our report dated February 16, 2011, expressed an unqualified opinion on those financial statements.

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants
Calgary, Canada

February 16, 2011

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

CONSOLIDATED STATEMENT OF INCOME
FOR THE THREE YEARS ENDED DECEMBER 31, 2010

| (Cdn$ millions, except per-share amounts) | 2010 | 2009 | 2008 |
|---|---|---|---|
| Revenues and Other Income | | | |
| Net Sales | 5,411 | 4,203 | 6,576 |
| Marketing and Other (Note 16) | 415 | 859 | 863 |
| | 5,826 | 5,062 | 7,439 |
| Expenses | | | |
| Operating | 1,354 | 916 | 924 |
| Depreciation, Depletion, Amortization and Impairment (Note 4) | 1,662 | 1,615 | 1,899 |
| Transportation and Other | 566 | 732 | 907 |
| General and Administrative | 439 | 434 | 210 |
| Exploration | 328 | 302 | 401 |
| Interest (Note 9) | 310 | 305 | 82 |
| Net Loss on Dispositions (Note 18) | 41 | – | – |
| | 4,700 | 4,304 | 4,423 |
| Income from Continuing Operations before Provision for Income Taxes | 1,126 | 758 | 3,016 |
| Provision for (Recovery of) Income Taxes (Note 17) | | | |
| Current | 1,127 | 773 | 857 |
| Future | (573) | (527) | 557 |
| | 554 | 246 | 1,414 |
| Net Income from Continuing Operations | 572 | 512 | 1,602 |
| Net Income from Discontinued Operations, Net of Tax (Note 20) | 625 | 24 | 113 |
| Net Income Attributable to Nexen Inc. | 1,197 | 536 | 1,715 |
| Earnings Per Common Share from Continuing Operations ($/share) (Note 21) | | | |
| Basic | 1.09 | 0.98 | 3.05 |
| Diluted | 1.08 | 0.96 | 3.01 |
| Earnings Per Common Share ($/share) (Note 21) | | | |
| Basic | 2.28 | 1.03 | 3.26 |

| | | | |
|---|---|---|---|
| Diluted | 2.27 | 1.01 | 3.22 |

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET
DECEMBER 31, 2010 AND 2009

| (Cdn$ millions, except per-share amounts) | 2010 | 2009 |
|---|---|---|
| ASSETS | | |
| Current Assets | | |
| Cash and Cash Equivalents | 1,005 | 1,700 |
| Restricted Cash | 40 | 198 |
| Accounts Receivable (Note 2) | 1,938 | 2,788 |
| Inventories and Supplies (Note 3) | 549 | 680 |
| Other | 142 | 185 |
| Assets Held for Sale (Note 20) | 748 | – |
| | | |
| Total Current Assets | 4,422 | 5,551 |
| | | |
| Property, Plant and Equipment (Note 4) | 15,249 | 15,492 |
| Future Income Tax Assets (Note 17) | 1,678 | 1,148 |
| Goodwill | 286 | 339 |
| Deferred Charges and Other Assets (Note 5) | 272 | 370 |
| | | |
| TOTAL ASSETS | 21,907 | 22,900 |
| | | |
| LIABILITIES | | |
| Current Liabilities | | |
| Accounts Payable and Accrued Liabilities (Note 8) | 2,545 | 3,038 |
| Accrued Interest Payable | 83 | 89 |
| Dividends Payable | 26 | 26 |
| Liabilities Held for Sale (Note 20) | 540 | – |
| | | |
| Total Current Liabilities | 3,194 | 3,153 |
| | | |
| Long-Term Debt (Note 9) | 5,079 | 7,251 |
| Future Income Tax Liabilities (Note 17) | 3,138 | 2,811 |
| Asset Retirement Obligations (Note 11) | 1,009 | 1,018 |
| Deferred Credits and Other Liabilities (Note 12) | 696 | 1,021 |
| | | |
| EQUITY (Note 14) | | |
| Nexen Inc. Shareholders' Equity | | |
| Common Shares, no par value | | |
| Authorized: Unlimited | | |
| Outstanding: 2010 – 525,706,403 shares | | |
| 2009 – 522,915,843 shares | 1,111 | 1,049 |
| Contributed Surplus | – | 1 |

| | | |
|---|---|---|
| Retained Earnings | 7,815 | 6,722 |
| Accumulated Other Comprehensive Loss | (219) | (190) |

| (Cdn$ millions, except per-share amounts) | 2010 | 2009 |
|---|---|---|
| Total Nexen Inc. Shareholders' Equity | 8,707 | 7,582 |
| Canexus Non-Controlling Interests (Note 20) | 84 | 64 |
| Total Equity | 8,791 | 7,646 |
| Commitments, Contingencies and Guarantees (Notes 15, 17 and 18) | | |
| TOTAL LIABILITIES AND EQUITY | 21,907 | 22,900 |

See accompanying notes to the Consolidated Financial Statements.

Approved on behalf of the Board:

(signed) "Marvin F. Romanow"

Director

(signed) "Thomas C. O'Neill"

Director

CONSOLIDATED STATEMENT OF CASH FLOWS
FOR THE THREE YEARS ENDED DECEMBER 31, 2010

| (Cdn$ millions) | 2010 | 2009 | 2008 |
|---|---|---|---|
| Operating Activities | | | |
| Net Income from Continuing Activities | 572 | 512 | 1,602 |
| Net Income from Discontinued Operations (Note 20) | 630 | 44 | 109 |
| Charges and Credits to Income not Involving Cash (Note 22) | 640 | 1,371 | 2,140 |
| Exploration Expense | 328 | 302 | 402 |
| Changes in Non-Cash Working Capital (Note 22) | 338 | (25) | 119 |
| Other | (159) | (318) | (18) |
| | 2,349 | 1,886 | 4.354 |
| Financing Activities | | | |
| Proceeds from Long-Term Notes | -- | 1,081 | -- |
| Repayment of Medium-Term Notes and Debentures | -- | -- | (125) |
| Proceeds from (Repayment of) Term Credit Facilities, Net | (1,538) | 728 | 803 |
| Repayment of Short-Term Borrowings, Net | -- | (1) | (4) |
| Proceeds from Canexus Long-Term Debt, Net | 112 | 94 | 31 |
| Dividends on Common Shares | (104) | (104) | (92) |
| Distributions Paid to Canexus Non-Controlling Interests | (17) | (14) | (17) |
| Issue of Common Shares and Exercise of Tandem Options for Shares (Note 14) | 55 | 57 | 64 |
| Repurchase of Common Shares for Cancellation (Note 14) | -- | -- | (338) |
| Other | (14) | (20) | -- |
| | (1,506) | 1,821 | 322 |
| Investing Activities | | | |
| Capital Expenditures | | | |
| Exploration and Development | (2,313) | (2,467) | (2,895) |
| Proved Property Acquistions | (79) | (755) | (22) |
| Energy Marketing, Chemicals, Corporate and Other | (210) | (275) | (149) |
| Proceeds on Disposition of Assets | 1,262 | 17 | 6 |
| Changes in Non-Cash Working Capital (Note 22) | (59) | (110) | (124) |
| Changes in Restricted Cash | 37 | (140) | 106 |
| Other | (60) | (13) | (111) |
| | (1,422) | (3,743) | (3,189) |

| (Cdn$ millions) | 2010 | 2009 | 2008 |
|---|---|---|---|
| Effect of Exchange Rate Changes on Cash and Cash Equivalents | (116) | (267) | 310 |
| Increase (Decrease) in Cash and Cash Equivalents | (695) | (303) | 1,797 |
| Cash and Cash Equivalents, Beginning of Year | 1,700 | 2,003 | 206 |
| Cash and Cash Equivalents, End of Year | 1,005 | 1,700 | 2,003 |

Cash and cash equivalents at December 31, 2010 consists of cash of $345 million (2009 – $210 million; 2008 – $355 million) and short-term investments of $660 million (2009 – $1,490 million; 2008 – $1,648 million).

See accompanying notes to Consolidated Financial Statements.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

CONSOLIDATED STATEMENT OF EQUITY
FOR THE THREE YEARS ENDED DECEMBER 31, 2010

| (Cdn$ millions) | 2010 | 2009 | 2008 |
|---|---|---|---|
| Common Shares, Beginning of Year | 1,049 | 981 | 917 |
| Issue of Common Shares | 50 | 45 | 41 |
| Exercise of Tandem Options for Shares | 5 | 12 | 23 |
| Accrued Liability Relating to Tandem Options Exercised for Common Shares | 7 | 11 | 22 |
| Repurchased Under Normal Course Issuer Bid (Note 14) | -- | -- | (22) |
| | | | |
| End of Year | 1,111 | 1,049 | 981 |
| | | | |
| Contributed Surplus, Beginning of Year | 1 | 2 | 3 |
| Exercise of Tandem Options | (1) | (1) | (1) |
| | | | |
| End of Year | -- | 1 | 2 |
| | | | |
| Retained Earnings, Beginning of Year | 6,722 | 6,290 | 4,983 |
| Net Income Attributable to Nexen Inc. | 1,197 | 536 | 1,715 |
| Dividends Declared on Common Shares | (104) | (104) | (92) |
| Repurchase of Common Shares for Cancellation (Note 14) | -- | -- | (316) |
| | | | |
| End of Year | | | |
| | 7,815 | 6,722 | 6,290 |
| Accumulated Other Comprehensive Loss, Beginning of Year | (190) | (134) | (293) |
| Other Comprehensive Income (Loss) Attributable to Nexen Inc. | (29) | (56) | 159 |
| End of Year1 | (219) | (190) | (134) |

| (Cdn$ millions) | 2010 | 2009 | 2008 |
|---|---|---|---|
| Canexus Non-Controlling Interests, Beginning of Year | 64 | 52 | 67 |
| Net Income (Loss) Attributable to Non-Controlling Interests | 5 | 27 | (5) |
| Distributions Declared to Non-Controlling Interests | (20) | (18) | (20) |
| Issue of Partnership Units to Non-Controlling Interests | 27 | 4 | 3 |
| Estimated Fair Value of Conversion Feature of Convertible Debenture Issue Attributable to Non-Controlling Interests | 8 | 4 | - |
| Other Comprehensive Income (Loss) Attributable to Canexus Non-Controlling Interests | - | (5) | 7 |
| End of Year | 84 | 64 | 52 |

1 Comprised of unrealized foreign currency translation adjustment.

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
FOR THE THREE YEARS ENDED DECEMBER 31, 2010

| (Cdn$ millions) | 2010 | 2009 | 2008 |
|---|---|---|---|
| Net Income Attributable to Nexen Inc. | 1,197 | 536 | 1,715 |
| Other Comprehensive Income (Loss), Net of Income Taxes: | | | |
| Foreign Currency Translation Adjustment: Net Gains (Losses) on Investment in Self-Sustaining Foreign Operations | (257) | (810) | 1,228 |
| Net Gains (Losses) on Foreign-Denominated Debt Hedges of Self-Sustaining Foreign Operations1 | 228 | 757 | (1,062) |
| Realized Translation Adjustments Recognized in Net Income | – | (3) | (7) |
| Other Comprehensive Income (Loss) Attributable to Nexen Inc. | (29) | (56) | 159 |
| | | | |
| Comprehensive Income Attributable to Nexen Inc. | 1,168 | 480 | 1,874 |

1Net of income tax expense for the year ended December 31, 2010 of $33 million (2009 – $109 million expense; 2008 – $145 million recovery).

See accompanying notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Cdn$ millions, except as noted

## 1. ACCOUNTING POLICIES

Our Consolidated Financial Statements are prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The impact of significant differences between Canadian and United States (US) GAAP on the Consolidated Financial Statements is disclosed in Note 24.

### (A) CONSOLIDATION

The Consolidated Financial Statements include the accounts of Nexen and our subsidiary companies (Nexen, we or our). All subsidiary companies, with the exception of Canexus Limited Partnership and its subsidiaries (Canexus), are wholly owned. All intercompany accounts and transactions are eliminated upon consolidation.

At December 31, 2010, we had a 62.7% interest in Canexus represented by 66.2 million Exchangeable LP Units. We had the right to nominate a majority of the members of the Board of Directors, who have the power to determine the strategic operating, investing and financing policies of Canexus. All assets, liabilities and results of operations of Canexus are consolidated and have been included in our Consolidated Financial Statements. Non-Nexen ownership interests in Canexus are shown as non-controlling interests. As disclosed in Notes 19 and 20, we sold our interest in Canexus in early 2011 and the assets, liabilities and operating results were reclassified as held for sale and discontinued operations as at December 31, 2010.

We proportionately consolidate our undivided interests in our oil and gas exploration, development and production activities conducted under joint venture arrangements. While the joint ventures under which these activities are carried out do not comprise distinct legal entities, they are operating entities. The significant operating policies of which are, by contractual arrangement, jointly controlled by all working interest parties.

### (B) USE OF ESTIMATES

We make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and revenues and expenses during the reporting period. Our management reviews these estimates on an ongoing basis, including those related to accruals, litigation, environmental and asset retirement obligations, recoverability of assets, income taxes, fair values of commodity trading inventories, fair values of derivative assets and liabilities, capital adequacy and the determination of proved reserves. Changes in facts and circumstances may result in revised estimates, and actual results may differ from these estimates.

### (C) CASH AND CASH EQUIVALENTS

Cash and cash equivalents includes short-term, highly liquid investments that mature within three months of their purchase. These investments are recorded at cost, which approximates fair value.

### (D) RESTRICTED CASH

Restricted cash includes margin deposits relating to our exchange-traded derivative contracts used in our energy marketing business.

(E) ACCOUNTS RECEIVABLE

Accounts receivable are recorded based on our revenue recognition policy (see Note 1(O)). Our allowance for doubtful accounts provides for specific doubtful receivables, as well as general counterparty credit risk evaluated using observable market information and internal assessments.

(F) INVENTORIES AND SUPPLIES

Inventories and supplies, other than inventory held for trading purposes, are stated at the lower of cost and net realizable value. Cost is determined using the first-in, first-out method. Inventory costs include expenditures and other costs, including depletion and depreciation, directly or indirectly incurred in bringing the inventory to its existing condition.

Commodity inventories in our energy marketing operations that are held for trading purposes are carried at fair value, less any costs to sell. Any changes in fair value are included as gains or losses in marketing and other income during the period of change.

(G) PROPERTY, PLANT AND EQUIPMENT (PP&E)

PP&E is recorded at cost and includes only recoverable costs that directly result in an identifiable future benefit. Unrecoverable costs, maintenance and turnaround costs are expensed as incurred. Improvements that increase capacity or extend the useful lives of the related assets are capitalized to PP&E. Major spare parts and standby equipment whose useful life is expected to last longer than one year are included with PP&E.

We follow successful efforts accounting for our oil and gas operations. Costs are initially capitalized to PP&E as unproved property costs. Once proved reserves are discovered, the costs are reclassified to proved property costs. Exploration drilling costs are capitalized as suspended exploration well costs pending evaluation as to whether sufficient quantities of reserves have been found to justify commercial production. If commercial quantities of reserves are not found, exploration drilling costs are expensed. All exploratory wells are evaluated for commercial viability on a regular basis following completion of drilling. Exploration drilling costs remain capitalized if a determination is made that a sufficient quantity of reserves has been found and sufficient progress is being made to assess the reserves and the economic and operating viability of a potential development. All other exploration costs, including geological and geophysical costs and annual lease rentals, are expensed as incurred. All development costs are capitalized as proved property costs. General and administrative costs that directly relate to acquisition, exploration and development activities are capitalized to PP&E.

We engage in research and development activities to develop or improve processes and techniques to extract oil and gas. Research involves investigating new knowledge. Development involves translating that knowledge into a new technology or process. Research costs are expensed as incurred. Development costs are deferred once technical feasibility is established and we intend to proceed with development. We defer these costs in PP&E until the asset is substantially complete and ready for productive use. Otherwise, development costs are expensed as incurred.

(H) DEPRECIATION, DEPLETION, AMORTIZATION AND IMPAIRMENT (DD&A)

Under successful efforts accounting, we deplete oil and gas capitalized costs using the unit-of-production method. Development and exploration drilling and equipping costs are depleted over remaining proved developed reserves and proved property acquisition costs are depleted over remaining proved reserves. DD&A is considered a cost of inventory when the oil and gas are produced. When the inventory is sold, the depletion is charged to DD&A expense.

We depreciate other plant and equipment costs using the straight-line method based on the estimated useful lives of the assets, which range from 3 to 30 years. Unproved property costs and major projects that are under construction or development are not depreciated, depleted or amortized.

We evaluate the carrying value of our PP&E whenever events or conditions occur which might indicate that the carrying value of properties on our balance sheet may not be recoverable from future cash flows. If the carrying value exceeds the sum of estimated undiscounted future cash flows, the property's value is impaired. The property is then assigned a fair value equal to its estimated future discounted net cash flows, and we expense the excess carrying value to DD&A. Our cash flow estimates require assumptions about future commodity prices, ultimate recoverability of oil and gas reserves, operating costs and other factors. Actual results can differ from these estimates.

In assessing the carrying values of our unproved properties, we take into account our future plans for these properties, the remaining terms of the leases and any other factors that may be indicators of potential impairment.

(I) CAPITALIZED INTEREST

We capitalize interest on major development projects until construction is complete using the weighted-average interest rate on all of our borrowings. Capitalized interest cannot exceed the actual interest incurred.

(J) CARRIED INTEREST

We conduct certain international operations jointly with foreign governments in accordance with production-sharing agreements pursuant to which proved reserves are recognized using the economic interest method. Under these agreements, we pay both our share and the government's share of operating and capital costs. We recover the government's share of these costs from future revenues or production over several years. The government's share of operating costs is recorded in operating expense when incurred, and capital costs are recorded in PP&E and expensed to DD&A in the year recovered. All recoveries are recorded as revenue in the year of recovery.

(K) GOODWILL

Our goodwill is primarily attributable to our United Kingdom operating segment. It has been recorded at cost and is not amortized. We test goodwill for impairment at least annually or whenever events or circumstances indicate that goodwill may be impaired. We base our test on the estimated fair value of the reporting unit. If goodwill is impaired, we reduce the carrying value to estimated fair value and an impairment loss is included in net income.

(L) FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

All financial assets and liabilities are recognized on the balance sheet initially at fair value when we become a party to the contractual provisions of the instrument. Subsequent measurement of the financial instruments is based on their classification. We have classified each financial instrument into one of the following categories: financial assets and liabilities held for trading, loans or receivables, financial assets held to maturity, financial assets available for sale and other financial liabilities. The classification depends on the characteristics and the purpose for which the financial instruments were acquired. Except in limited circumstances, the classification of financial instruments is not subsequently changed.

Financial instruments carried at fair value on our balance sheet include cash and cash equivalents, restricted cash and derivatives used for trading and non-trading purposes. Realized and unrealized gains and losses from financial assets and liabilities carried at fair value are recognized in net income in the periods such gains and losses arise. Transaction costs related to these financial assets and liabilities are included in net income when incurred.

Financial instruments we carry at cost or amortized cost include our accounts receivable, accounts payable and accrued liabilities, accrued interest payable, dividends payable, short-term borrowings and long-term debt. Transaction costs are included in net income when incurred for these types of financial instruments except for short-term borrowings and long-term debt. These transaction costs are included with the initial fair value, and the instrument is carried at amortized cost using the effective interest rate method. Gains and losses on financial assets and liabilities carried at cost or amortized cost are recognized in net income when these assets or liabilities settle.

DERIVATIVES RELATED TO NON-TRADING ACTIVITIES

We may use derivative instruments such as physical purchase and sales contracts, forwards, futures, swaps and options for non-trading purposes to manage fluctuations in commodity prices, foreign currency exchange rates and interest rates (see Notes 6 and 7). We record these instruments at fair value at the balance sheet date and record changes in fair value as net gains or losses in marketing and other income during the period of change unless the requirements for hedge accounting are met.

DERIVATIVES RELATED TO TRADING ACTIVITIES

Our energy marketing operations use derivative instruments for marketing and trading crude oil, natural gas, natural gas liquids and power, including commodity contracts settled with physical delivery, exchange-traded futures and options, and non-exchange traded forwards, swaps and options.

We record these instruments at fair value at the balance sheet date and record changes in fair value as net gains or losses in marketing and other income during the period of change. The fair value of these instruments is included with accounts receivable or payable if we anticipate settling the instruments within a year of the balance sheet date. If we anticipate settling the instruments beyond 12 months, we include them with deferred charges and other assets or deferred credits and other liabilities.

HEDGE ACCOUNTING

Hedge accounting may be used when there is a high degree of correlation between price movements in the derivative instruments and the items designated as being hedged. Nexen formally documents all hedges and the risk management objectives at the inception of the hedge. Derivative instruments that have been designated and qualify for hedge accounting are classified as either cash flow or fair value hedges.

For cash flow hedges, changes in the fair value of a financial instrument designated as a cash flow hedge are recognized in net income in the same period as the hedged item. Any fair value change in the financial instrument before that period is recognized on the balance sheet. The effective portion of this fair value change is recognized in other comprehensive income, with any ineffectiveness recognized in marketing and other income during the period of change.

For fair value hedges, both the financial instrument designated as a fair value hedge and the underlying commitment are recognized on the balance sheet at fair value. Changes in the fair value of both are reflected in net income.

Nexen had no cash flow or fair value hedges in place at December 31, 2010 or 2009.

For hedges of net investments, gains and losses resulting from foreign exchange translation of our net investments in self-sustaining foreign operations and the effective portion of the hedging items are recorded in other comprehensive income. Amounts included in accumulated other comprehensive income are reclassified to income when realized.

(M) ASSET RETIREMENT OBLIGATIONS

We provide for future asset retirement obligations on our resource properties, facilities, production platforms and pipelines based on estimates established by current legislation and industry practices. The asset retirement obligation is initially measured at fair value and capitalized to PP&E as an asset retirement cost. The obligation is accreted through DD&A expense until it is expected to settle, and the cost is amortized through DD&A expense over the life of the respective asset. The fair value of the obligation is estimated by discounting expected future cash outflows to settle the asset retirement obligation using a weighted-average, credit-adjusted risk-free interest rate. Nexen recognizes period-to-period changes due to the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash outflows. Actual retirement costs are recorded against the obligation when incurred. Any difference between the recorded asset retirement obligation and the actual retirement costs incurred is recorded as a gain or loss in the settlement period.

We own interests in assets for which the fair value of the asset retirement obligations cannot be reasonably determined because the assets currently have an indeterminate life and we cannot determine when remediation activities would take place. These assets include our interest in Syncrude's upgrader and sulphur pile, and our interest in the Long Lake upgrader. The estimated future recoverable reserves at Syncrude and Long Lake are significant and, given the long life of these assets, we are unable to determine when asset retirement activities would take place. Furthermore, the Syncrude plant and the Long Lake upgrader can both continue to run indefinitely with ongoing maintenance activities. The retirement obligations for these assets will be recorded in the first year in which the obligation to remediate becomes determinable.

(N) PENSION AND OTHER POST-RETIREMENT BENEFITS

Our employee post-retirement benefit programs consist of contributory and non-contributory defined benefit and defined contribution pension plans, as well as other postretirement benefit programs.

For our defined benefit plans, we provide benefits to retirees based on their length of service and final average earnings. The cost of pension benefits earned by employees in our defined benefit pension plans is actuarially determined using the projected-benefit method prorated on service and our best estimate of the plans’ investment performance, salary escalations and retirement ages of employees. To calculate the plans’ expected returns, assets are measured at fair value. Past service costs arising from plan amendments, and net actuarial gains and losses that exceed 10% of the greater of the accrued benefit obligation and the fair value of plan assets, are expensed in equal amounts over the expected average remaining service life of the employee group. Benefits paid out of Nexen’s defined benefit plan are indexed to 75% of the annual rate of inflation less 1% to a maximum increase of 5%. Measurement date for our defined benefit plans is December 31.

Our defined contribution pension plan benefits are based on plan contributions. Company contributions to the defined contribution plan are expensed as incurred.

Other post-retirement benefits include group life and supplemental health insurance for eligible employees and their dependants. Costs are accrued as compensation in the period employees work; however, these future obligations are not funded.

(O) REVENUE RECOGNITION

OIL AND GAS

Revenue from the production of crude oil and natural gas is recognized when title passes to the customer. In Canada and the US, our customers primarily take title when the crude oil or natural gas reaches the end of the pipeline. For our other international operations, our customers generally take title when the crude oil is loaded onto tankers. When we produce or sell more or less oil or natural gas than our share, production overlifts and underlifts occur. We record overlifts as liabilities and underlifts as assets. We settle these over time as liftings are equalized or in cash when production ends.

Revenue represents Nexen’s share and is recorded net of royalty obligations to governments and other mineral interest owners. For our international operations, all government interests, except for income taxes, are considered royalty obligations. Our revenue also includes the recovery of costs paid on behalf of foreign governments in international locations.

CHEMICALS

Revenue from our chemicals operations is only recognized when our products are delivered to our customers. Delivery takes place when we have a sales contract specifying delivery volumes and sales prices. We assess customer credit-worthiness before entering into sales contracts to minimize collection risk.

ENERGY MARKETING

Substantially all of the physical purchase and sales contracts entered into by our energy marketing operation are considered to be derivative instruments. Accordingly, financial and physical commodity contracts (collectively, derivative instruments) held by our energy marketing operation are stated at fair value on the balance sheet. We record any change in fair value as a gain or loss in marketing and other income unless requirements for hedge accounting are met.

Any margin earned by our energy marketing operation on the sale of our proprietary oil and gas production is included in marketing and other income. Sales of our proprietary production are recorded at average monthly market-based prices and reported in our oil and gas segments. Intercompany profits and losses between segments are eliminated.

We assess customer credit-worthiness before entering into contracts and provide for netting terms to minimize collection risk. Amounts are recorded on a net basis where we have a legally enforceable right and intention to offset.

(P) FOREIGN CURRENCY TRANSLATION

Our foreign operations, which are considered financially and operationally independent, are translated from their functional currency into Canadian dollars at the balance sheet date exchange rate for assets and liabilities and at the monthly average exchange rate for revenues and expenses. Gains and losses resulting from this translation are included in other comprehensive income.

We have designated our US-dollar debt (excluding debt related to Canexus) as a hedge against our net investment in US-dollar self-sustaining foreign operations. Gains and losses resulting from the translation of the designated US-dollar debt are included in other comprehensive income. If our US-dollar debt, net of income taxes, exceeds our US-dollar investment in foreign operations, then the gains or losses attributable to such excess are included in marketing and other income in the Consolidated Statement of Income.

Monetary balance sheet amounts denominated in a currency other than a functional currency are translated into the functional currency using exchange rates at the balance sheet dates. Gains and losses arising from this translation are included in marketing and other income in the Consolidated Statement of Income.

(Q) TRANSPORTATION

We pay to transport the crude oil, natural gas and chemical products that we have sold and often bill our customers for the transportation. This transportation is presented in our Consolidated Financial Statements as transportation and other expense. Amounts billed to our customers are presented within marketing and other income. Our energy marketing operation has received cash payments in exchange for assuming certain transportation obligations from third parties. These cash payments were recorded as deferred liabilities and were recognized in net income as the transportation is used. These obligations were sold in 2010.

(R) LEASES

We classify leases entered into as either capital or operating leases. Leases that transfer substantially all of the benefits and risks of ownership to us are accounted for as capital leases, and the related assets are included with PP&E and amortized on a straight-line basis over the period of expected use, consistent with other PP&E. Rental payments under operating leases are expensed as incurred.

(S) STOCK-BASED COMPENSATION

Our stock-based compensation consists of tandem option (TOPs), stock appreciation right (STARs), and restricted share unit (RSUs) plans.

Tandem options to purchase common shares are granted to officers and employees at the discretion of the board of directors. Each tandem option gives the holder a right to either purchase one Nexen common share at the exercise price or to receive a cash payment equal to the excess of the market value of the common share over the exercise price. Options granted vest over three years and are exercisable on a cumulative basis over five years. At the time of the grant, the exercise price equals the market value of the common share. Beginning in 2010, certain awards contain a performance vesting condition.

We record obligations for the tandem options using the intrinsic-value method of accounting and recognize compensation expense in the Consolidated Statement of Income. Obligations are accrued on a graded vesting basis and represent the difference between the market value of our common shares and the exercise price of the options. The obligations are revalued each reporting period based on the change in the market value of our common shares and the number of graded vested options outstanding. We reduce the liability when the options are surrendered for cash. When the options are exercised for stock, the accrued liability is transferred to share capital.

For employees eligible to retire during the vesting period, the compensation expense is recognized over the period from the grant date to the retirement eligibility date on a graded vesting basis. In instances where an employee is eligible to retire on the grant date of the stock-based award, compensation expense is recognized in full at that date.

Under our STARs plan, employees are entitled to cash payments equal to the excess of market price of the common share over the exercise price of the right. The vesting period and other terms of the plan are similar to the tandem option plan and include a performance vesting feature for certain awards. At the time of grant, the exercise price equals market value of the common share. We account for stock appreciation rights to employees on the same basis as our tandem options. Obligations are accrued as compensation expense over the graded vesting period of the stock appreciation rights.

Under our RSU plan, employees are entitled to receive a cash payment equal to the market value of one common share on the vesting date for each RSU granted. All RSUs vest evenly over three years and are exercised and paid as they vest. The obligation for RSUs are revalued each period based on the market value of our common shares and the number of graded vested RSUs outstanding.

(T) INCOME TAXES

We follow the liability method of accounting for income taxes. This method recognizes income tax assets and liabilities at current rates, based on temporary differences in reported amounts for financial statement and tax purposes. The effect of a change in income tax rates on future income tax assets and future income tax liabilities is recognized in income when substantively enacted.

We do not provide for foreign withholding taxes on the undistributed earnings of our foreign subsidiaries, as we intend to invest such earnings indefinitely in foreign operations.

(U) CHANGES IN ACCOUNTING PRINCIPLES

OIL AND GAS RESERVE ESTIMATES

On January 6, 2010, the Financial Accounting Standards Board issued guidance for Oil and Gas Reserve Estimation and Disclosure, which is effective for years ended on or after December 31, 2009. The guidance: i) expands the definition of oil and gas producing activities to include unconventional sources such as oil sands; ii) changes the price used in reserve estimation from the year-end price to the simple average of the first-day-of-the-month price for the previous 12 months; and iii) requires disclosures for geographic areas that represent 15% or more of proved reserves. The information required by this standard has been included in the Supplementary Data (Unaudited).

We follow the successful efforts method of accounting for our oil and gas activities, which uses the estimated proved reserves we believe are recoverable from our oil and gas properties. Specifically, reserves estimates are used to calculate our unit-of-production depletion rates and to assess, when necessary, our oil and gas assets for impairment. Adoption of the amendments changed our estimate of reserves used to calculate depletion in 2010. As a result of the amendments, depletion expense increased by $47 million, net income decreased by $32 million, and earnings per common share decreased by $0.07/share, for the year ended December 31, 2010.

NEW ACCOUNTING PRONOUNCEMENTS

Nexen will be required to adopt International Financial Reporting Standards (IFRS) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011.

## 2. ACCOUNTS RECEIVABLE

| | 2010 | 2009 |
|---|---|---|
| Trade | | |
| Energy Marketing | 929 | 1,410 |
| Energy Marketing Derivative Contracts (Note 6) | 149 | 466 |
| Oil and Gas | 822 | 823 |
| Chemicals and Other | 2 | 44 |
| | 1,902 | 2,743 |
| Non-Trade | 80 | 99 |
| | 1,982 | 2,842 |
| Allowance for Doubtful Receivables | (44) | (54) |
| Total1 | 1,938 | 2,788 |

1At December 31, 2010, accounts receivable related to our chemicals operations have been included with assets held for sale (see Notes 19 and 20).

## 3. INVENTORIES AND SUPPLIES

| | 2010 | 2009 |
|---|---|---|
| Finished Products | | |
| Energy Marketing | 452 | 548 |
| Oil and Gas | 34 | 25 |
| Chemicals and Other | – | 12 |
| | 486 | 585 |
| Work in Process | 5 | 7 |
| Field Supplies | 58 | 88 |
| Total1 | 549 | 680 |

1At December 31, 2010, inventories and supplies related to our chemicals operations have been included with assets held for sale (see Notes 19 and 20).

4. PROPERTY, PLANT AND EQUIPMENT

| | 2010 | | | 2009 | | |
|---|---|---|---|---|---|---|
| | Cost | Accumulated DD&A | Net Book Value | Cost | Accumulated DD&A | Net Book Value |
| Oil and Gas | | | | | | |
| Canada1 | 8,729 | 883 | 7,846 | 9,664 | 2,038 | 7,626 |
| UK | 6,610 | 3,273 | 3,337 | 6,115 | 2,664 | 3,451 |
| Syncrude | 1,545 | 305 | 1,240 | 1,463 | 270 | 1,193 |
| US | 3,913 | 2,689 | 1,224 | 3,900 | 2,529 | 1,371 |
| Yemen | 765 | 727 | 38 | 800 | 728 | 72 |
| Yemen – Carried Interest | 1,614 | 1,585 | 29 | 1,662 | 1,594 | 68 |
| Other Countries2 | 1,362 | 88 | 1,274 | 930 | 99 | 831 |
| | 24,538 | 9,550 | 14,988 | 24,534 | 9,922 | 14,612 |
| Energy Marketing | 195 | 66 | 129 | 259 | 83 | 176 |
| Chemicals3 | – | – | – | 1,135 | 562 | 573 |
| Corporate and Other | 397 | 265 | 132 | 371 | 240 | 131 |
| Total | 25,130 | 9,881 | 15,249 | 26,299 | 10,807 | 15,492 |

1Includes capitalized costs related to our insitu oil sands (Long Lake and future phases) of $6,179 million (2009 – $6,045 million).

2Includes capitalized costs related to Usan development, offshore west Africa of $1,222 million (2009 – $779 million).

3Chemicals net book value of $643 million is included in assets held for sale at December 31, 2010 (see Notes 19 and 20).

Capitalized costs includes $4,514 million (2009 – $8,740 million) relating to unproved properties and projects under construction or development. These costs are currently not being depreciated, depleted or amortized and relate to projects under construction and not yet in service such as our Usan development offshore Nigeria, future oil sands phases, shale gas development and suspended exploratory well costs.

DEPRECIATION, DEPLETION, AMORTIZATION AND IMPAIRMENT

Our DD&A expense for 2010 includes non-cash impairment charges of $93 million on properties in the Gulf of Mexico. In the third quarter, low natural gas prices resulted in impairment on three shelf properties. We impaired two properties during the fourth quarter where declining production performance and higher estimated future abandonment costs reduced the properties' estimated future cash flows.

Our DD&A expense in 2009 included non-cash impairment charges of $78 million at three natural gas properties in Canada and the US Gulf of Mexico. Year-end natural gas proved reserves at these properties were lower as a result of weak natural gas prices throughout 2009. DD&A expense in 2009 also includes $49 million of costs for our Perth discovery in the North Sea, where we expensed allocated acquisition costs as we are unlikely to proceed with development of this prospect.

These properties were written down to their estimated fair value based on their estimated future discounted net cash flows. The estimated future cash flows incorporate a risk-adjusted discount rate and management’s estimates of future prices, capital expenditures and production. Based on these significant unobservable inputs, the measurements were considered Level 3 within the fair value hierarchy.

SUSPENDED EXPLORATION WELL COSTS

The following table shows the changes in capitalized exploratory well costs for the two years ended December 31, 2010, and does not include amounts that were initially capitalized and subsequently expensed in the same period. Suspended exploration well costs are included in property, plant and equipment.

| | 2010 | 2009 |
|---|---|---|
| Beginning of Year | 794 | 518 |
| Exploratory Well Costs Capitalized Pending the Determination of Proved Reserves | 232 | 396 |
| Capitalized Exploratory Well Costs Charged to Expense | (14) | (56) |
| | | |
| Transfers to Wells, Facilities and Equipment Based on Determination of Proved Reserves | (517) | (21) |
| Effects of Foreign Exchange Rate Changes | (30) | (43) |
| End of Year | 465 | 794 |

The following table provides an aging of capitalized exploratory well costs based on the date drilling was completed as at December 31, 2010.

| Aging of Suspended Exploration Wells | United States | Canada | United Kingdom | Nigeria | Total |
|---|---|---|---|---|---|
| Less than 1 year | 88 | 4 | 98 | – | 190 |
| 1-3 years | – | 93 | 4 | 13 | 110 |
| 4-5 years | 111 | – | 37 | – | 148 |
| Greater than 5 years | – | – | – | 17 | 17 |
| Total | 199 | 97 | 139 | 30 | 465 |

As at December 31, 2010, we have exploratory costs that have been capitalized for more than one year relating to our interests in two exploratory blocks in the Gulf of Mexico ($111 million), certain shale gas and coalbed methane exploratory activities in Canada ($93 million), three exploratory blocks in the UK North Sea ($41 million) and our interest in an exploratory block offshore Nigeria ($30 million). These costs relate to projects with successful exploration wells for which we have not been able to recognize proved reserves. We are assessing all of these wells and projects and are working with our partners to prepare development plans, drill additional appraisal wells or otherwise assess commercial viability.

## 5. DEFERRED CHARGES AND OTHER ASSETS

| | 2010 | 2009 |
|---|---|---|
| Long-Term Energy Marketing Derivative Contracts (Note 6) | 116 | 225 |
| Defined Benefit Pension Asset (Note 13) | 75 | 60 |
| Long-Term Capital Prepayments | 12 | 27 |
| Other | 69 | 58 |
| Total | 272 | 370 |

## 6. FINANCIAL INSTRUMENTS

Financial instruments carried at fair value on our balance sheet include cash and cash equivalents, restricted cash and derivatives used for trading and non-trading purposes. Our other financial instruments, including accounts receivable, accounts payable, accrued interest payable, dividends payable, short-term borrowings and long-term debt, are carried at cost or amortized cost. The carrying value of our short-term receivables and payables approximates their fair value because the instruments are near maturity.

In our energy marketing group, we enter into contracts to purchase and sell crude oil, natural gas and other energy commodities and use derivative contracts, including futures, forwards, swaps and options, for hedging and trading purposes (collectively derivatives). We also use derivatives to manage commodity price risk and foreign currency risk for non-trading purposes. We categorize our derivative instruments as trading or non-trading activities and carry the instruments at fair value on our balance sheet. The fair values are included with amounts receivable or payable and are classified as long-term or short-term based on anticipated settlement date. Any change in fair value is included in marketing and other income.

We carry our long-term debt at amortized cost using the effective interest rate method. At December 31, 2010, the estimated fair value of our long-term debt was $5,290 million (2009 – $7,594 million) as compared to the carrying value of $5,079 million (2009 – $7,251 million). The fair value of long-term debt is estimated based on prices provided by quoted markets and third-party brokers.

DERIVATIVES

### (A) DERIVATIVE CONTRACTS RELATED TO TRADING ACTIVITIES

During 2010, we sold substantially all of our North American natural gas marketing operations, our oil lease gathering, pipeline and storage assets in North Dakota and Montana and our European gas and power marketing operations, as described in Note 18. Our energy marketing group primarily focuses on our crude oil marketing activities in North America, Europe and Asia.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

Our energy marketing group engages in various activities, including the purchase and sale of physical commodities and the use of financial instruments such as commodity and foreign exchange futures, forwards and swaps to economically hedge exposures and generate revenue. These contracts are accounted for as derivatives and, where applicable, are presented net on the balance sheet in accordance with netting arrangements. The fair value and carrying amounts related to derivative instruments held by our energy marketing operations are as follows:

| | 2010 | 2009 |
|---|---|---|
| Commodity Contracts | 149 | 463 |
| Foreign Exchange Contracts | – | 3 |
| Accounts Receivable (Note 2) | 149 | 466 |
| Commodity Contracts | 116 | 225 |
| Deferred Charges and Other Assets (Note 5)1 | 116 | 225 |
| Total Trading Derivative Assets | 265 | 691 |
| Commodity Contracts | 168 | 410 |
| Foreign Exchange Contracts | – | 46 |
| Accounts Payable and Accrued Liabilities (Note 8) | 168 | 456 |
| Commodity Contracts | 115 | 212 |
| Deferred Credits and Other Liabilities (Note 12)1 | 115 | 212 |
| Total Trading Derivative Liabilities | 283 | 668 |
| Total Net Trading Derivative Contracts | (18 ) | 23 |

1These derivative contracts settle beyond 12 months and are considered non-current; once settlement is within 12 months, they are included in accounts receivable or accounts payable.

Excluding the impact of netting arrangements, the fair value of derivative instruments is as follows:

| | 2010 | 2009 |
|---|---|---|
| Current Trading Assets | 467 | 2,625 |
| Non-Current Trading Assets | 156 | 716 |
| Total Trading Derivative Assets | 623 | 3,341 |
| Current Trading Liabilities | 486 | 2,615 |
| Non-Current Trading Liabilities | 155 | 703 |
| Total Trading Derivative Liabilities | 641 | 3,318 |
| Total Net Trading Derivative Contracts | (18 ) | 23 |

Trading revenues generated by our energy marketing group include gains and losses on derivative instruments and non-derivative instruments such as physical inventory. The following trading revenues were recognized in marketing and other income:

| | 2010 | 2009 |
|---|---|---|
| Commodity | 342 | 1,011 |
| Foreign Exchange | (8) | (68) |
| Marketing Revenue, Net (Note 16) | 334 | 943 |

As an energy marketer, we may undertake several transactions during a period to execute a single sale of physical product. Each transaction may be represented by one or more derivative instruments including a physical buy, physical sell, and in many cases, numerous financial instruments for economically hedging and trading purposes. The absolute notional volumes associated with our derivative instrument transactions are as follows:

| | 2010 | 2009 |
|---|---|---|
| Natural Gas (bcf/d) | 6.5 | 21.1 |
| Crude Oil (mmbbls/d) | 3.1 | 3.5 |
| Power (GWh/d) | 69.5 | 217.3 |
| Foreign Exchange (US$ millions) | 2,457 | 2,981 |
| Foreign Exchange (Euro millions) | 53 | 376 |

(B) DERIVATIVE CONTRACTS RELATED TO NON-TRADING ACTIVITIES

The fair value and carrying amounts of derivative instruments related to non-trading activities are as follows:

| | 2010 | 2009 |
|---|---|---|
| Accounts Receivable | 9 | 13 |
| Deferred Charges and Other Assets1 | – | 4 |
| Total Non-Trading Derivative Assets | 9 | 17 |
| Accounts Payable and Accrued Liabilities | – | 26 |
| Total Non-Trading Derivative Liabilities | – | 26 |
| Total Net Non-Trading Derivative Contracts2 | 9 | (9) |

1These derivative contracts settle beyond 12 months and are considered non-current.

2The net fair value of these derivatives is equal to the gross fair value before consideration of netting arrangements and collateral posted or received with counterparties.

CRUDE OIL PUT OPTIONS

During 2010, we purchased put options on 100,000 bbls/d of our 2011 crude oil production. These options establish a monthly WTI floor price of between US$50/bbl and US$63/bbl and provide a base level of price protection without limiting our upside to higher prices. The options settle monthly and unexpired options are recorded at fair value throughout their term. As a result, changes in forward crude oil prices

created gains or losses on these options at each period end. The put options were purchased for $33 million and are carried at fair value. As at December 31, 2010 the fair value of the options was approximately $9 million and we recorded a fair value loss of $24 million in the year.

In 2009, we purchased put options on 90,000 bbls/d of our 2010 crude oil production. These options were purchased for $39 million and established a WTI floor price of US$50/bbl on these volumes. At December 31, 2009, higher crude oil prices reduced the fair value of the options to $17 million and we recorded a fair value loss of $22 million in 2009. Strengthening crude oil prices in 2010 reduced the fair value of these options to nil and we recorded a fair value loss of $17 million in 2010.

In 2008, we purchased put options on approximately 70,000 bbls/d of our 2009 crude oil production. These options were purchased for $14 million and established an annual Dated Brent floor price of US$60/ bbl on these volumes. At December 31, 2008, the put options had an estimated fair value of $233 million due to lower crude oil prices. Strengthening crude oil prices in 2009 reduced the fair value of these options to nil and we recorded a fair value loss of $229 million in 2009.

The crude oil put options are carried at fair value and are classified as long-term or short-term based on their anticipated settlement date. Fair value of the put options is supported by multiple quotes obtained from third-party brokers, which were validated with observable market data to the extent possible. Any change in fair value is included in marketing and other income.

| | December 31, 2010 | | | | |
|---|---|---|---|---|---|
| | Notional Volumes (bbls/d) | Term | Average Floor Price (US$/bbl) | Fair Value (Cdn$ millions) | Change in Fair Value (Cdn$ millions) |
| WTI Crude Oil Put Options (monthly) | 100,000 | 2011 | 56 | 9 | (24) |

| | December 31, 2009 | | | | |
|---|---|---|---|---|---|
| | Notional Volumes (bbls/d) | Term | Average Floor Price (US$/bbl) | Fair Value (Cdn$ millions) | Change in Fair Value (Cdn$ millions) |
| WTI Crude Oil Put Options (monthly) | 60,000 | 2010 | 50 | 13 | (12) |
| WTI Crude Oil Put Options (annual) | 30,000 | 2010 | 50 | 4 | (10) |
| | | | | 17 | (22) |

## (C) FAIR VALUE OF DERIVATIVES

For purposes of estimating the fair value of our derivative contracts, wherever possible, we utilize quoted market prices and, if not available, estimates from third-party brokers. These broker estimates are corroborated with multiple sources and/or other observable market data utilizing assumptions that market participants would use when pricing the asset or liability, including assumptions about risk and market liquidity. Inputs to fair valuations may be readily observable, market-corroborated or generally unobservable. We utilize valuation techniques that seek to maximize the use of observable inputs and minimize the use of unobservable inputs. To value longer-term transactions and transactions in less active markets for which pricing information is not generally available, unobservable inputs may be used.

We classify the fair value of our derivatives according to the following hierarchy based on the amount of observable inputs used to value the instruments.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 consists of financial instruments such as exchange-traded derivatives, and we use information from markets such as the New York Mercantile Exchange.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reported date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value, volatility factors and broker quotations, which can be substantially observed or corroborated in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter physical forwards and options, including those that have prices similar to quoted market prices. We obtain information from sources such as the Natural Gas Exchange (formerly Netthruput), independent price publications and over-the-counter broker quotes.

Level 3 – Valuations in this level are those with inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value. Level 3 instruments may include items based on pricing services or broker quotes where we are unable to verify the observability of inputs into their prices. Level 3 instruments include longer-term transactions, transactions in less active markets or transactions at locations for which pricing information is not available. In these instances, internally developed methodologies are used to determine fair value, which primarily includes extrapolation of observable future prices to similar locations, similar instruments or later time periods.

The following table includes our derivatives that are carried at fair value for our trading and non-trading activities as at December 31, 2010 and 2009. Financial assets and liabilities are classified in the fair value hierarchy in their entirety based on the least observable input that is significant to the fair value measurement. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect placement within the fair value hierarchy levels.

| Net Derivatives at December 31, 2010 | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Trading Derivatives (Commodity Contracts) | (17) | (18) | 17 | (18) |
| Non-Trading Derivatives | – | 9 | – | 9 |
| Total | (17) | (9) | 17 | (9) |
| Net Derivatives at December 31, 2009 | Level 1 | Level 2 | Level 3 | Total |
| Commodity Contracts | (143) | 167 | 42 | 66 |
| Foreign Exchange Contracts | – | (43) | – | (43) |
| Trading Derivatives | (143) | 124 | 42 | 23 |
| Non-Trading Derivatives | – | (9) | – | (9) |
| Total | (143) | 115 | 42 | 14 |

A reconciliation of changes in the fair value of our derivatives classified as Level 3 for the years ended December 31, 2010 and 2009 is provided below:

| | 2010 | 2009 |
|---|---|---|
| Level 3 Net Derivatives at January 1 | 42 | (82) |
| Realized and unrealized gains (losses) | 19 | 74 |
| Purchases | – | 4 |
| Settlements | (44) | 54 |
| Transfers into Level 3 | – | – |
| Transfers out of Level 3 | – | (8) |
| Level 3 Net Derivatives at December 31 | 17 | 42 |
| Unsettled gains (losses) relating to instruments still held as of December 31 | 19 | 66 |

Items classified in Level 3 are generally economically hedged such that gains or losses on positions classified in Level 3 are often offset by gains or losses on positions classified in Level 1 or 2. Transfers into or out of Level 3 represent existing assets and liabilities that were either previously categorized as a higher level for which the inputs became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period. Fair values of instruments in Level 3 are determined using broker quotes, pricing services and internally-developed inputs. We performed a sensitivity analysis of inputs used to calculate the fair value of Level 3 instruments. Using reasonably possible alternative assumptions, the fair value of Level 3 instruments at December 31, 2010 would change by $5 million.

## 7. RISK MANAGEMENT

### (A) MARKET RISK

We invest in significant capital projects, purchase and sell commodities, issue short-term borrowings and long-term debt, and invest in foreign operations. These activities expose us to market risks from changes in commodity prices, foreign currency rates and interest rates, which could affect our earnings and the value of the financial instruments we hold. We use derivatives for trading and non-trading purposes as part of our overall risk management policy to manage these market risk exposures.

The following market risk discussion relates primarily to commodity price risk and foreign currency risk related to our financial instruments as our exposure to interest rate risk is immaterial given that the majority of our debt is fixed rate.

### COMMODITY PRICE RISK

We are exposed to commodity price movements as part of our normal oil and gas operations, particularly in relation to the prices received for our crude oil and natural gas. Commodity price risk related to conventional and synthetic crude oil prices is our most significant market risk exposure. Crude oil and natural gas are sensitive to numerous worldwide factors, many of which are beyond our control, and are generally sold at contract or posted prices. Changes in global supply and demand fundamentals in the crude oil market and geopolitical events can significantly affect crude oil prices. Changes in crude oil and natural gas prices may significantly affect our results of operations and cash generated from operating activities. Consequently, these changes also may affect the value of our oil and gas properties, our level of spending for exploration and development, and our ability to meet our obligations as they come due.

The majority of our oil and gas production is sold under short-term contracts, exposing us to the risk of near-term price movements. Other energy contracts we enter into also expose us to commodity price risk between the time we purchase and sell contracted volumes. We actively manage these risks by using derivative contracts such as commodity put options.

Our energy marketing business is focused on maximising the value of our equity production and, to a lesser extent, providing services to customers and suppliers to meet their energy commodity needs. We primarily market and trade physical crude oil in selected regions of the world. We accomplish this by buying and selling physical commodities, by acquiring and holding rights to physical transportation and storage assets for these commodities, and by building strong relationships with our customers and suppliers. Prior to the related disposition in 2010, we also marketed and traded physical natural gas, electricity and other commodities. In order to manage the commodity and foreign exchange price risks that come from this physical business, we use financial derivative contracts, including energy-related futures, forwards, swaps and options, as well as currency swaps or forwards.

Our risk management activities make use of tools such as Value-at-Risk (VaR) and stress testing. VaR is a statistical estimate of the expected profit or loss of a portfolio of positions assuming normal market conditions. We use a 95% confidence interval and an assumed two-day holding period in our measure, although actual results can differ from this estimate in abnormal market conditions or if positions are held longer than two days based on market views or a lack of market liquidity to exit them. We estimate VaR primarily by using the Variance-Covariance method based on historical commodity price volatility and correlation inputs where available and by historical simulation in other situations. Our estimate is based upon the following key assumptions:

- changes in commodity prices are either normally or “T” distributed;
- price volatility remains stable; and
- price correlation relationships remain stable.

We have defined VaR limits for different segments of our energy marketing business. These limits are calculated on an economic basis and include physical and financial derivatives, as well as physical transportation and storage capacity contracts accounted for as executory contracts in our financial statements. We monitor our positions against these VaR limits daily. Our year-end, annual high, annual low and average VaR amounts are as follows:

| Value-at-Risk (Cdn$ millions) | 2010 | 2009 |
|---|---|---|
| Year-End | 11 | 11 |
| High | 15 | 24 |
| Low | 4 | 9 |
| Average | 10 | 15 |

If a market shock occurred, the key assumptions underlying our VaR estimate could be exceeded and the potential loss could be greater than our estimate. We perform stress tests on a regular basis to complement VaR and assess the impact of abnormal changes in prices on our positions.

Foreign currency risk

Foreign currency risk is created by fluctuations in the fair values or cash flows of financial instruments due to changes in foreign exchange rates. A substantial portion of our activities are transacted in or referenced to US dollars, including:

- sales of crude oil and natural gas products;

capital spending and expenses for our oil and gas operations;

commodity derivative contracts used primarily by our energy marketing group; and

short-term borrowings and long-term debt.

We manage our exposure to fluctuations between the US and Canadian dollar by maintaining our expected net cash flows and borrowings in the same currency. Cash inflows generated by our foreign operations and borrowings on our US-dollar debt facilities are generally used to fund US-dollar capital expenditures and debt repayments. We maintain revolving Canadian and US-dollar borrowing facilities that can be used or repaid depending on expected net cash flows.

We designate most of our US-dollar borrowings as a hedge against our US-dollar net investment in self-sustaining foreign operations. The foreign exchange gains or losses related to the effective portion of our designated US-dollar debt are included in accumulated other comprehensive income in equity. Our net investment in self-sustaining foreign operations and our designated US-dollar debt at December 31, 2010 and 2009 are as follows:

| (US$ millions) | December 31, 2010 | December 31, 2009 |
|---|---|---|
| Net Investment in Self-Sustaining Foreign Operations | 4,443 | 4,492 |
| Designated US-Dollar Debt | 4,393 | 4,492 |

For the year ended December 31, 2010, the undesignated portion of our US-dollar debt resulted in a net foreign exchange loss of $3 million ($3 million, net of income tax expense) and is included in marketing and other income (2009 – $151 million ($132 million, net of income tax expense)). A one-cent change in the US dollar to Canadian dollar exchange rate would increase or decrease our accumulated other comprehensive income by approximately $38 million, net of income tax, and would increase or decrease our net income by approximately $3 million, net of income tax.

We also have exposures to currencies other than the US dollar, including a portion of our UK operating expenses, capital spending and future asset retirement obligations, which are denominated in British pounds and Euros. We do not have any material exposure to highly inflationary foreign currencies. In our energy marketing group, we enter into transactions in various currencies, including Canadian and US dollars, British pounds and Euros. We actively manage significant currency exposures using forward contracts and swaps.

## (B) CREDIT RISK

Credit risk affects our oil and gas operations and our energy marketing activities, and is the risk of loss if counterparties do not fulfill their contractual obligations. Most of our credit exposures are with counterparties in the energy industry, including integrated oil companies, refiners and utilities, and are subject to normal industry credit risk. Over 80% of our exposure is with these large energy companies. This concentration of risk within the energy industry is reduced because of our broad base of domestic and international counterparties. We take the following measures to reduce this risk:

assess the financial strength of our counterparties through a rigorous credit analysis process;

limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;

routinely monitor credit risk exposures, including sector, geographic and corporate concentrations of credit, and report these to our Executive Risk Management Committee and the Finance Committee of the board;

- set counterparty credit limits based on rating agency credit ratings and internal assessments of company and industry analysis;
- review counterparty credit limits regularly; and
- use standard agreements where possible that allow for the netting of exposures associated with a single counterparty.

We believe these measures minimize our overall credit risk; however, there can be no assurance that these processes will protect us against all losses from non-performance.

At December 31, 2010, three counterparties individually made up more than 10% of our credit exposure. These counterparties are major integrated oil companies with strong investment-grade ratings. Two other counterparties made up more than 5% of our credit exposure. The following table illustrates the composition of credit exposure by credit rating:

| Credit Rating | 2010 | | 2009 | |
|---|---|---|---|---|
| A or higher | 71 | % | 67 | % |
| BBB | 20 | % | 26 | % |
| Non-Investment Grade | 9 | % | 7 | % |
| Total | 100 | % | 100 | % |

Our maximum counterparty credit exposure at the balance sheet date consists primarily of the carrying amounts of non-derivative financial assets such as cash and cash equivalents, restricted cash, accounts receivable, as well as the fair value of derivative financial assets. We have provided an allowance of $44 million for credit risk with our counterparties. In addition, we incorporate the credit risk associated with counterparty default, as well as Nexen's own credit risk, into our estimates of fair value.

Collateral received from customers at December 31, 2010 includes $38 million of cash and $104 million of letters of credit. The cash received is included in accounts payable and accrued liabilities.

## (C) LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations as they fall due. We require liquidity specifically to fund capital requirements, satisfy financial obligations as they become due and to operate our energy marketing business. We generally rely on operating cash flows to provide liquidity and we also maintain significant undrawn committed credit facilities. At December 31, 2010, we had $4 billion of cash and available undrawn committed lines of credit. This includes $1 billion of cash and cash equivalents on hand and undrawn committed term credit facilities of $3 billion, of which $322 million was supporting letters of credit at December 31, 2010. Our committed term credit facilities are available until 2014 unless extended. We also have $464 million of undrawn, uncommitted credit facilities, of which $112 million was supporting letters of credit at year end.

The following table details the contractual maturities for our non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2010:

| | December 31, 2010 | | | | |
|---|---|---|---|---|---|
| | Total | < 1 Year | 1-3 Years | 4-5 Years | > 5 Years |
| Long-Term Debt (Note 9) | 5,171 | – | 497 | 249 | 4,425 |
| Cumulative Interest on Long-Term Debt1 | 7,286 | 336 | 670 | 612 | 5,668 |
| Total | 12,457 | 336 | 1,167 | 861 | 10,093 |

1At December 31, 2010 none of our variable interest rate debt was drawn.

The following table details contractual maturities for our derivative financial liabilities. The balance sheet amounts for derivative financial liabilities included below are not materially different from the contractual amounts due on maturity.

| | December 31, 2010 | | | | |
|---|---|---|---|---|---|
| | Total | < 1 Year | 1-3 Years | 4-5 Years | > 5 Years |
| Trading Derivatives (Note 6) | 283 | 168 | 105 | 5 | 5 |

At December 31, 2010, the collateral we have posted with counterparties includes $4 million of cash and $185 million of letters of credit related to our trading activities. Cash posted is included with our accounts receivable. Cash collateral is not normally applied to contract settlement. Once a contract has been settled, the collateral amounts are refunded. In the event of a default, the cash would likely be retained.

The commercial agreements our energy marketing group enters into often include financial assurance provisions that allow us and our counterparties to effectively manage credit risk. The agreements can require collateral to be posted if an adverse credit-related event occurs, such as a drop in credit ratings to non-investment grade. These obligations are reflected on our balance sheet. The posting of collateral secures the payment of such amounts. We have significant undrawn credit facilities and cash to fund these potential collateral requirements.

Our exchange-traded derivative contracts are also subject to margin requirements. We have margin deposits of $40 million (2009 – $198 million), which have been included in restricted cash.

## 8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

| | 2010 | 2009 |
|---|---|---|
| Energy Marketing Payables | 1,015 | 1,366 |
| Energy Marketing Derivative Contracts (Note 6) | 168 | 456 |
| Accrued Payables | 676 | 619 |
| Trade Payables | 164 | 210 |
| Income Taxes Payable | 345 | 179 |
| Stock-Based Compensation | 30 | 72 |
| Other | 147 | 136 |
| Total[1] | 2,545 | 3,038 |

[1] At December 31, 2010, accounts payable and accrued liabilities related to our chemical operations have been included in liabilities held for sale (see Notes 19 and 20).

## 9. SHORT-TERM BORROWINGS AND LONG-TERM DEBT

| | 2010 | 2009 |
|---|---|---|
| Canexus Term Credit Facilities, due 2012[1] | – | 233 |
| Canexus Notes, due 2013[1] | – | 52 |
| Notes, due 2013 (US$500 million) (A) | 497 | 523 |
| Term Credit Facilities, due 2014 (B) | – | 1,570 |
| Canexus Convertible Debentures, due 2014[1] | – | 46 |
| Notes, due 2015 (US$250 million) (C) | 249 | 262 |
| Notes, due 2017 (US$250 million) (D) | 249 | 262 |
| Notes, due 2019 (US$300 million) (E) | 298 | 314 |
| Notes, due 2028 (US$200 million) (F) | 199 | 209 |
| Notes, due 2032 (US$500 million) (G) | 497 | 523 |
| Notes, due 2035 (US$790 million) (H) | 786 | 827 |
| Notes, due 2037 (US$1,250 million) (I) | 1,243 | 1,308 |
| Notes, due 2039 (US$700 million) (J) | 696 | 733 |
| Subordinated Debentures, due 2043 (US$460 million) (K) | 457 | 481 |
| | 5,171 | 7,343 |
| Unamortized Discount and Debt Issue Costs | (92) | (92) |
| Total | 5,079 | 7,251 |

[1]Included in liabilities held for sale at December 31, 2010 (see Notes 19 and 20).

### (A) NOTES, DUE 2013

During November 2003, we issued US$500 million of notes. Interest is payable semi-annually at a rate of 5.05% and the principal is to be repaid in November 2013. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.2%.

### (B) TERM CREDIT FACILITIES

We have unsecured term credit facilities of $3 billion (US$3 billion) available until July 2014, none of which were drawn at December 31, 2010 (2009 – $1.6 billion (US$1.5 billion)). Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime rate loans, US-dollar base rate loans or British pound call-rate loans. Interest is payable at floating rates. During 2010, the weighted-average interest rate was 1.6% (2009 – 1.0%). At December 31, 2010, $322 million (US$324 million) of these facilities was utilized to support outstanding letters of credit (2009 – $407 million (US$389 million)).

### (C) NOTES, DUE 2015

During March 2005, we issued US$250 million of notes. Interest is payable semi-annually at a rate of 5.2% and the principal is to be repaid in March 2015. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.15%.

(D) NOTES, DUE 2017

During May 2007, we issued US$250 million of notes. Interest is payable semi-annually at a rate of 5.65% and the principal is to be repaid in May 2017. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.20%.

(E) NOTES, DUE 2019

During July 2009, we issued US$300 million of notes. Interest is payable semi-annually at a rate of 6.2% and the principal is to be repaid in July 2019. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.40%.

(F) NOTES, DUE 2028

During April 1998, we issued US$200 million of notes. Interest is payable semi-annually at a rate of 7.4% and the principal is to be repaid in May 2028. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.25%.

(G) NOTES, DUE 2032

During March 2002, we issued US$500 million of notes. Interest is payable semi-annually at a rate of 7.875% and the principal is to be repaid in March 2032. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.375%.

(H) NOTES, DUE 2035

During March 2005, we issued US$790 million of notes. Interest is payable semi-annually at a rate of 5.875% and the principal is to be repaid in March 2035. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.20%.

(I) NOTES, DUE 2037

During May 2007, we issued US$1,250 million of notes. Interest is payable semi-annually at a rate of 6.4% and the principal is to be repaid in May 2037. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.35%.

(J) NOTES, DUE 2039

During July 2009, we issued US$700 million of notes. Interest is payable semi-annually at a rate of 7.5% and the principal is to be repaid in July 2039. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.45%.

(K) SUBORDINATED DEBENTURES, DUE 2043

During November 2003, we issued US$460 million of unsecured subordinated debentures. Interest is payable quarterly at a rate of 7.35%, and the principal is to be repaid in November 2043. We may redeem part or all of the debentures at any time. The redemption price is equal to the par value of the principal amount plus any accrued and unpaid interest to the redemption date. We may choose to redeem the principal amount with either cash or common shares.

## (L) LONG-TERM DEBT REPAYMENTS

The following schedule outlines the required timetable of debt repayments and does not preclude earlier repayments as per the provisions of the respective notes.

| | |
|---|---|
| 2011 | – |
| 2012 | – |
| 2013 | 497 |
| 2014 | – |
| 2015 | 249 |
| Thereafter | 4,425 |
| Total1 | 5,171 |

1 Excludes repayments related to our chemical operations (see Notes 19 and 20).

## (M) DEBT COVENANTS

Some of our debt instruments contain covenants with respect to certain financial ratios and our ability to grant security. At December 31, 2010 and 2009, we were in compliance with all covenants.

## (N) SHORT-TERM BORROWINGS

Nexen has uncommitted, unsecured credit facilities of approximately $464 million (US$467 million), (2009 – $492 million (US$470 million)), none of which were drawn at either December 31, 2010 or 2009. We utilized $112 million (US$112 million) of these facilities to support outstanding letters of credit at December 31, 2010 (2009 – $86 million (US$82 million)). Interest is payable at floating rates. During 2010, the weighted-average interest rate on our short-term borrowings was 0.9% (2009 -2.1%).

## (O) INTEREST EXPENSE

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Long-Term Debt | 361 | 360 | 303 |
| Other | 29 | 17 | 19 |
| Total | 390 | 377 | 322 |
| Less: Capitalized | (80) | (72) | (240) |
| Total1 | 310 | 305 | 82 |

1Excludes interest expense related to our chemical operations (see Notes 19 and 20).

Capitalized interest relates to and is included as part of the cost of oil and gas properties. The capitalization rates are based on our weighted-average cost of borrowings. In 2009, we ceased capitalizing interest on Phase 1 of Long Lake.

## 10. CAPITAL DISCLOSURE

Our objective for managing our capital structure is to ensure that we have the financial capacity, liquidity and flexibility to fund our investment in full-cycle exploration and development of conventional and unconventional resources and for energy marketing activities. We generally rely on operating cash flows to fund capital investments. However, given the long cycle-time of some of our development projects, which require significant capital investment prior to cash flow generation, and volatile commodity prices, it is not unusual for capital expenditures to exceed our cash flow from operating activities in any given period. As such, our financing needs depend on the timing of expected net cash flows in a particular development or commodity cycle. This requires us to maintain financial flexibility and liquidity. Our capital management policies are aimed at:

- maintaining an appropriate balance between short-term borrowings, long-term debt and equity;
- maintaining sufficient undrawn committed credit capacity to provide liquidity;
- ensuring ample covenant room, permitting us to draw on credit lines as required; and
- ensuring we maintain a credit rating that is appropriate for our circumstances.

We have the ability to make adjustments to our capital structure by issuing additional equity or debt, returning cash to shareholders and making adjustments to our capital investment programs. Our capital consists of equity, short-term borrowings, long-term debt, and cash and cash equivalents as follows:

| Net Debt1 | 2010 | 2009 |
|---|---|---|
| Long-Term Debt | 5,079 | 7,251 |
| Less: Cash and Cash Equivalents | (1,005 ) | (1,700 ) |
| Total2 | 4,074 | 5,551 |
| Equity3 | 8,707 | 7,582 |

1Includes all of our borrowings and is calculated as long-term debt and short-term borrowings less cash and cash equivalents.

2December 31, 2010 excludes Net Debt related to our chemical operations that are included in assets and liabilities held for sale (see Notes 19 and 20).

3Equity is the historical issue of equity and accumulated retained earnings.

We monitor the leverage in our capital structure by reviewing the ratio of net debt to cash flow from operating activities and interest coverage ratios at various commodity prices.

We use the ratio of net debt to cash flow from operating activities as a key indicator of our leverage and to monitor the strength of our balance sheet. Net debt is a non-GAAP measure that does not have any standard meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by others. We calculate net debt using the GAAP measures of long-term debt and short-term borrowings less cash and cash equivalents (excluding restricted cash).

For the 12 months ended December 31, 2010, the net debt to cash flow from operating activities ratio (before changes in non-cash working capital and other) was 1.9 times compared to 2.5 times at December 31, 2009. While we typically expect the target ratio to fluctuate between 1.0 and 2.0 times under normalized commodity prices, this can be higher or lower depending on commodity price volatility, where we are in the investment cycle or when we identify strategic opportunities requiring additional investment. Whenever we exceed our target ratio, we assess whether we need to develop a strategy to reduce our leverage and lower this ratio back to target levels over time.

Our interest coverage ratio monitors our ability to fund the interest requirements associated with our debt. Our interest coverage increased from 8.5 times at the end of 2009 to 9.3 times at December 31, 2010. Interest coverage is calculated by dividing our twelve-month trailing earnings before interest, taxes, DD&A, exploration expense and other non-cash items (adjusted EBITDA) by interest expense before capitalized interest. Adjusted EBITDA is a non-GAAP measure that is calculated using net income excluding interest expense, provision for income taxes, exploration expense, DD&A, impairment and other non-cash expenses. The calculation of adjusted EBITDA is set out in the following table and is unlikely to be comparable to similar measures presented by others:

| | 2010 | 2009 |
|---|---|---|
| Net Income Attributable to Nexen Inc. | 1,197 | 536 |
| Add: | | |
| Interest Expense | 310 | 305 |
| Provision for Income Taxes | 554 | 246 |
| Depreciation, Depletion, Amortization and Impairment | 1,662 | 1,615 |
| Exploration Expense | 328 | 302 |
| Recovery of Non-Cash Stock-Based Compensation | (41) | (10) |
| Change in Fair Value of Crude Oil Put Options | 41 | 251 |
| Items Related to Discontinued Operations | (475) | – |
| Other Non-Cash Items | 50 | 72 |
| Adjusted EBITDA | 3,626 | 3,317 |

## 11. ASSET RETIREMENT OBLIGATIONS

Changes in carrying amounts of the asset retirement obligations associated with our PP&E are as follows:

| | 2010 | 2009 |
|---|---|---|
| Asset Retirement Obligations, Beginning of Year | 1,053 | 1,059 |
| Obligations Incurred with Development Activities | 32 | 27 |
| Obligations Settled | (43) | (42) |
| Accretion Expense | 66 | 70 |
| Revisions to Estimates | 169 | 13 |
| Obligations Related to Dispositions1 | (166) | – |
| Effects of Changes in Foreign Exchange Rate | (47) | (74) |
| End of Year2, 3 | 1,064 | 1,053 |

1Includes obligations associated with discontinued operations of $163 million.

2Obligations due within 12 months of $55 million (2009 – $35 million) have been included in accounts payable and accrued liabilities.

3Obligations relating to our oil and gas activities amount to $1,064 million (2009 – $1,002 million), and obligations relating to our chemicals business amount to nil (2009 – $51 million). At December 31, 2010, asset retirement obligations associated with our chemicals business are included in liabilities held for sale (see Note 20).

Our total estimated undiscounted inflated asset retirement obligations amount to $2,552 million (2009 – $2,341 million). We discounted the total estimated asset retirement obligations using a weighted-average, credit-adjusted risk-free rate of 6% (2009 – 5.9%). Approximately $306 million included in our asset retirement obligations will be settled over the next five years. The remaining obligations settle beyond five years and will be funded by future cash flows from our operations.

## 12. DEFERRED CREDITS AND OTHER LIABILITIES

| | 2010 | 2009 |
|---|---|---|
| Deferred Tax Credit | 367 | 503 |
| Long-Term Marketing Derivative Contracts (Note 6) | 115 | 212 |
| Defined Benefit Pension Obligations (Note 13) | 75 | 74 |
| Capital Lease Obligations | 42 | 61 |
| Deferred Transportation Revenue | – | 55 |
| Other | 97 | 116 |
| Total | 696 | 1,021 |

During 2008, we completed an internal reorganization and financing of our assets in the North Sea, which provided us with an additional one-time tax deduction in the UK. As these transactions were completed within our consolidated group, we are unable to recognize the benefit of the tax deductions until the assets are recognized in income by way of a sale to a third party or depletion through use. At December 31, 2010, we deferred recognizing $367 million (2009 – $503 million) of tax credits in net income.

## 13. PENSION AND OTHER POST-RETIREMENT BENEFITS

Nexen has contributory and non-contributory defined benefit and defined contribution pension plans, as well as other postretirement benefit programs, which cover substantially all employees. Syncrude has a defined benefit plan for its employees, and we disclose only our proportionate share of this plan.

### (A) DEFINED BENEFIT PENSION PLANS

The cost of pension benefits earned by employees is determined using the projected-benefit method prorated on employment services and is expensed as services are rendered. We fund these plans according to federal and provincial government regulations by contributing to trust funds administered by an independent trustee. These funds are invested primarily in equities and bonds. The supplemental plan is not tax-efficient to fund. Instead, obligations are secured by an irrevocable letter of credit.

| | 2010 | | | | |
|---|---|---|---|---|---|
| | Nexen | | | Syncrude | Total |
| | Registered (Funded) | Supplemental1 (Unfunded) | Total | | |
| Change in Projected Benefit Obligation (PBO) | | | | | |
| Beginning of Year | 243 | 76 | 319 | 125 | 444 |
| Service Cost | 17 | 4 | 21 | 5 | 26 |
| Interest Cost | 15 | 5 | 20 | 7 | 27 |
| Plan Participants' Contributions | 6 | – | 6 | 1 | 7 |
| Actuarial Loss/(Gain) | 26 | 15 | 41 | 19 | 60 |
| Benefits Paid | (16) | (3) | (19) | (6) | (25) |
| End of Year1, 2 | 291 | 97 | 388 | 151 | 539 |
| Change in Fair Value of Plan Assets | | | | | |
| Beginning of Year | 264 | – | 264 | 69 | 333 |

| | | | | | |
|---|---|---|---|---|---|
| Actual Return on Plan Assets | 28 | – | 28 | 8 | 36 |
| Employer’s Contribution | 30 | 3 | 33 | 14 | 47 |
| Plan Participants' Contributions | 6 | – | 6 | 1 | 7 |
| Benefits Paid | (16) | (3) | (19) | (5) | (24) |
| End of Year | 312 | – | 312 | 87 | 399 |

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

| | 2010 | | | | |
|---|---|---|---|---|---|
| | Nexen | | | Syncrude | Total |
| | Registered (Funded) | Supplemental1 (Unfunded) | Total | | |
| Reconciliation of Funded Status | | | | | |
| Funded Status1 | 21 | (97) | (76) | (64) | (140) |
| Items Not Yet Recognized in Earnings | | | | | |
| Unamortized Prior Service Costs | 1 | (1) | – | – | – |
| Unamortized Net Actuarial Loss | 53 | 32 | 85 | 52 | 137 |
| Net Recognized Pension Asset (Liability) | 75 | (66) | 9 | (12) | (3) |
| Accounts Recorded in the Consolidated Balance Sheet | | | | | |
| Deferred Charges and Other Assets (Note 5) | 75 | – | 75 | – | 75 |
| Accounts Payable and Accrued Liabilities | – | (3) | (3) | – | (3) |
| Deferred Credits and Other Liabilities (Note 12) | – | (63) | (63) | (12) | (75) |
| Net Recognized Pension Asset (Liability) | 75 | (66) | 9 | (12) | (3) |
| Assumptions (%) | | | | | |
| Accrued Benefit Obligation at December 31 | | | | | |
| Discount Rate | 5.25 | 5.25 | | 5.25 | |
| Long-Term Rate of Employee Compensation Increase | 4.00 | 4.00 | | 4.45 | |
| Benefit Cost for Year Ended December 31 | | | | | |
| Discount Rate | 6.00 | 6.00 | | 6.00 | |
| Long-Term Rate of Employee Compensation Increase | 4.00 | 4.00 | | 4.45 | |
| Long-Term Annual Rate of Return on Plan Assets | 7.00 | – | | 7.50 | |

| | 2009 | | | | |
|---|---|---|---|---|---|
| | Nexen | | | Syncrude | Total |
| | Registered (Funded) | Supplemental1 (Unfunded) | Total | | |
| Change in Projected Benefit Obligation (PBO) | | | | | |
| Beginning of Year | 203 | 62 | 265 | 107 | 372 |
| Service Cost | 14 | 4 | 18 | 5 | 23 |
| Interest Cost | 14 | 4 | 18 | 7 | 25 |
| Plan Participants' Contributions | 6 | – | 6 | 1 | 7 |
| Actuarial Loss/(Gain) | 16 | 8 | 24 | 10 | 34 |
| Benefits Paid | (10) | (2) | (12) | (5) | (17) |
| End of Year1, 2 | 243 | 76 | 319 | 125 | 444 |

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

| | 2009 | | | | |
|---|---|---|---|---|---|
| | Nexen | | | Syncrude | Total |
| | Registered (Funded) | Supplemental1 (Unfunded) | Total | | |
| Change in Fair Value of Plan Assets | | | | | |
| Beginning of Year | 153 | – | 153 | 57 | 210 |
| Actual Return on Plan Assets | 40 | – | 40 | 9 | 49 |
| Employer's Contribution | 75 | 2 | 77 | 7 | 84 |
| Plan Participants' Contributions | 6 | – | 6 | 1 | 7 |
| Benefits Paid | (10) | (2) | (12) | (5) | (17) |
| End of Year | 264 | – | 264 | 69 | 333 |
| Reconciliation of Funded Status | | | | | |
| Funded Status1 | 21 | (76) | (55) | (56) | (111) |
| Items Not Yet Recognized in Earnings | | | | | |
| Unamortized Prior Service Costs | 2 | (1) | 1 | – | 1 |
| Unamortized Net Actuarial Loss | 37 | 18 | 55 | 39 | 94 |
| Net Recognized Pension Asset (Liability) | 60 | (59) | 1 | (17) | (16) |
| Accounts Recorded in the Consolidated Balance Sheet | | | | | |
| Deferred Charges and Other Assets (Note 5) | 60 | – | 60 | – | 60 |
| Accounts Payable and Accrued Liabilities | – | (2) | (2) | – | (2) |
| Deferred Credits and Other Liabilities (Note 12) | – | (57) | (57) | (17) | (74) |
| Net Recognized Pension Asset (Liability) | 60 | (59) | 1 | (17) | (16) |
| Assumptions (%) | | | | | |
| Accrued Benefit Obligation at December 31 | | | | | |
| Discount Rate | 6.00 | 6.00 | | 6.00 | |
| Long-Term Rate of Employee Compensation Increase | 4.00 | 4.00 | | 5.00 | |
| Benefit Cost for Year Ended December 31 | | | | | |
| Discount Rate | 6.50 | 6.50 | | 6.50 | |
| Long-Term Rate of Employee Compensation Increase | 4.00 | 4.00 | | 5.00 | |
| Long-Term Annual Rate of Return on Plan Assets | 7.00 | – | | 8.50 | |

1Includes self-funded obligations for supplemental benefits to the extent that the benefit is limited by statutory guidelines. The self-funded obligations for supplemental benefits are backed by an irrevocable letter of credit.

2The accumulated benefit obligations (the projected benefit obligation excluding future salary increases) of the Nexen plan was $256 million at December 31, 2010, (2009 – $211 million). Nexen’s supplemental pension plan’s accumulated benefit obligation was $78 million at December 31, 2010 (2009 – $65 million). Nexen’s share of Syncrude’s employee pension plan’s accumulated benefit obligation was $120 million at December 31, 2010 (2009 – $96 million).

Net Pension Expense Recognized Under Our Defined Benefit Pension Plans

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Nexen | | | |
| Cost of Benefits Earned by Employees | 21 | 18 | 23 |
| Interest Cost on Benefits Earned | 20 | 18 | 17 |
| Actual (Return) Loss on Plan Assets | (28) | (40) | 54 |
| Actuarial (Gains)/Losses | 41 | 24 | (39) |
| Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs | 54 | 20 | 55 |
| Difference Between Actual and Expected Return on Plan Assets | 8 | 26 | (71) |
| Difference Between Actual and Recognized Actuarial Losses | (38) | (21) | 41 |
| Difference Between Actual and Recognized Past Service Costs | 1 | – | 1 |
| Net Pension Expense | 25 | 25 | 26 |
| Syncrude1 | | | |
| Cost of Benefits Earned by Employees | 5 | 5 | 4 |
| Interest Cost on Benefits Earned | 7 | 7 | 7 |
| Actual (Return) Loss on Plan Assets | (8) | (9) | 19 |
| Actuarial (Gains)/Losses | 19 | 10 | (25) |
| Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs | 23 | 13 | 5 |
| Difference Between Actual and Expected Return on Plan Assets | 2 | 4 | (26) |
| Difference Between Actual and Recognized Actuarial Losses | (16) | (8) | 27 |
| Net Pension Expense | 9 | 9 | 6 |
| Total Net Pension Expense2 | 34 | 34 | 32 |

1Nexen’s share of Syncrude’s plan.

2Pension expense is reported principally within operating expense and general and administrative expense in the Consolidated Statement of Income.

(B) PLAN ASSET ALLOCATION AT DECEMBER 31

Our investment goal for the assets in our defined benefit pension plans is to preserve capital and earn a long-term rate of return on assets, net of all management expenses, in excess of the inflation rate. Investment funds are managed by external fund managers based on policies approved by the Board of Directors and Pension Committee of Nexen. Nexen’s investment strategy is to diversify plan assets between debt and equity securities of Canadian and non-Canadian corporations that are traded on recognized stock exchanges. Allowable and prohibited investment types are also prescribed in Nexen’s investment policies.

Nexen’s investment strategy is to ensure appropriate diversification between and within asset classes in order to optimize the return/risk trade-off. Nexen’s policy allows investment in equities, fixed income, cash and real estate assets. Derivative instruments can be utilized as deemed appropriate by the Pension

Committee. Nexen's expected long-term annual rate of return on plan assets assumption is based on a mix of historical market returns for debt and equity securities. The returns that are used as the basis for future expectations are derived from the major asset categories in which Nexen is currently invested.

The target allocations for plan assets are identified in the table below. Equity securities primarily include investments in large-cap companies, both Canadian and foreign, and debt securities primarily include corporate bonds of companies from diversified industries and Canadian Treasury issuances. The Canadian fixed income pooled funds invest in low-cost fixed income index funds that track the DEX Universe Bond Index. The Canadian equity pooled funds invest in low-cost equity index funds that track the S&P/TSX Composite Index. The foreign equity pooled funds invest in low-cost equity index funds that track the S&P 500 and the MSCI EAFE Indexes.

Nexen also has an unregistered self-funded supplemental benefits pension plan that covers obligations that are limited by statutory guidelines. These benefits are backed by an irrevocable letter of credit and payments are made from Nexen's general operating revenues.

Syncrude's pension plans are governed and administered separately from Nexen's. Syncrude's investment assets are subject to similar investment goals, policies and strategies.

| Plan Asset Allocation (%) | Expected 2011 | 2010 | 2009 |
|---|---|---|---|
| Nexen | | | |
| Equity Securities | 65 | 65 | 62 |
| Debt Securities | 35 | 35 | 38 |
| Total | 100 | 100 | 100 |
| Syncrude | | | |
| Equity Securities | 60 | 60 | 71 |
| Debt Securities | 40 | 40 | 29 |
| Total | 100 | 100 | 100 |

The fair values of Nexen's defined benefit pension plan assets at December 31, 2010 by asset category are as follows:

| | Fair Value Measurements at December 31, 2010 | | | |
|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total |
| Asset Category | | | | |
| Cash | 3 | – | – | 3 |
| Pooled Funds | | | | |
| Canadian Fixed Income | – | 105 | – | 105 |
| Canadian Equity | – | 78 | – | 78 |

| | | | | |
|---|---|---|---|---|
| Foreign Equity | – | 126 | – | 126 |
| Total | 3 | 309 | – | 312 |

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

The fair values of Nexen's defined benefit pension plan assets at December 31, 2009 by asset category are as follows:

| | Fair Value Measurements at December 31, 2009 | | | |
|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total |
| Asset Category | | | | |
| Cash | 9 | – | – | 9 |
| Equity Securities | | | | |
| Canadian Equity | 36 | – | – | 36 |
| Pooled Funds | | | | |
| Canadian Fixed Income | – | 90 | – | 90 |
| Canadian Equity | – | 30 | – | 30 |
| Foreign Equity | – | 99 | – | 99 |
| Total | 45 | 219 | – | 264 |

The fair values of Syncrude's defined benefit pension plan assets at December 31, 2010 by asset category are as follows:

| | Fair Value Measurements at December 31, 2010 | | | |
|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total |
| Asset Category | | | | |
| Cash | 1 | – | – | 1 |
| Pooled Funds | | | | |
| Canadian Fixed Income | – | 32 | – | 32 |
| Canadian Equity | – | 22 | – | 22 |
| Foreign Equity | – | 31 | – | 31 |
| Other Types of Investment | | | | |
| Other | – | – | 1 | 1 |
| Total | 1 | 85 | 1 | 87 |

The fair values of Syncrude's defined benefit pension plan assets at December 31, 2009 by asset category are as follows:

| | Fair Value Measurements at December 31, 2009 | | | |
|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total |
| Asset Category | | | | |
| Cash | 1 | – | – | 1 |
| Pooled Funds | | | | |
| Canadian Fixed Income | – | 17 | – | 17 |
| Canadian Equity | – | 19 | – | 19 |
| Foreign Equity | – | 30 | – | 30 |
| Other Types of Investment | | | | |
| Other | – | – | 2 | 2 |
| Total | 1 | 66 | 2 | 69 |

## (C) DEFINED CONTRIBUTION PENSION PLANS

Under these plans, pension benefits are based on plan contributions. During 2011, Canadian pension expense for these plans was $7 million (2009-$8 million; 2008-$6 million). During 2010, US pension expense for these plans was $6 million (2009-$7 million; 2008-$4 million) and UK pension expense for these plans was $6 million (2009 - $6 million; 2008 - $6 million).

## (D) POST-RETIREMENT BENEFITS

Nexen provides certain post-retirement benefits, including group life and supplemental health insurance, to eligible employees and their dependents. The present value of Nexen employees' future post-retirement benefits at December 31, 2010 was $15 million (2009-$14 million).

## (E) EMPLOYER FUNDING CONTRIBUTIONS AND BENEFIT PAYMENTS

Canadian regulators have prescribed funding requirements for our defined benefit plans. Funding contributions over the last three years have met these requirements and also included additional discretionary contributions permitted by law to ensure the plans are adequately funded in light of expected future changes in assumptions. For our defined contribution pension plans, we make contributions on behalf of our employees and no further obligation exists. Funding contributions related to our defined benefit plans are:

Expected

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| Nexen | 11 | 33 | 77 |
| Syncrude | 14 | 14 | 7 |
| Total Defined Benefit Contribution | 25 | 47 | 84 |

Our most recent funding valuation was prepared as of June 30, 2010. Our next funding valuation is required by June 30, 2013. Syncrude's most recent funding valuation was prepared as of December 31, 2009. The next funding valuation is required as at December 31, 2012.

Our total benefit payments in 2010 were $19 million for Nexen (2009-$12 million). Our share of Syncrude's total benefit payments in 2010 was $6 million (2009-$5 million). Our estimated future payments are as follows:

| | Defined Benefit | | Other | |
|---|---|---|---|---|
| | Nexen | Syncrude | Nexen | Syncrude |
| 2011 | 12 | 6 | 3 | – |
| 2012 | 12 | 6 | 4 | – |
| 2013 | 13 | 6 | 4 | – |
| 2014 | 14 | 7 | 4 | – |
| 2015 | 14 | 7 | 5 | – |
| 2016-2020 | 84 | 45 | 28 | 2 |

## 14. EQUITY

### (A) AUTHORIZED CAPITAL

Authorized share capital consists of an unlimited number of common shares of no par value and an unlimited number of Class A preferred shares of no par value, issuable in series.

### (B) ISSUED COMMON SHARES AND DIVIDENDS

| (thousands of shares) | 2010 | 2009 | 2008 |
|---|---|---|---|
| Issued Common Shares, Beginning of Year | 522,916 | 519,449 | 528,305 |
| Issue of Common Shares for Cash | | | |
| Exercise of Tandem Options | 527 | 1,146 | 1,911 |
| Dividend Reinvestment Plan | 1,654 | 1,328 | 871 |
| Employee Flow-through Shares | 609 | 993 | 499 |
| Repurchased under Normal Course Issuer Bid | – | – | (12,137 ) |
| End of Year | 525,706 | 522,916 | 519,449 |
| Dividends Declared per Common Share ($/share) | 0.20 | 0.20 | 0.18 |
| Cash Consideration (Cdn$ millions) | | | |
| Exercise of Tandem Options | 5 | 12 | 23 |
| Dividend Reinvestment Plan | 35 | 29 | 25 |
| Employee Flow-through Shares | 15 | 16 | 16 |
| Total | 55 | 57 | 64 |

During the year 1,654,173 common shares were issued under the Dividend Reinvestment Plan, leaving a balance of 621,171 common shares (2009 – 2,275,344; 2008 – 3,603,841) reserved for issuance at December 31, 2010. In 2011, we plan to request board approval to increase the number of common shares reserved for issuance under the Dividend Reinvestment Plan. Dividends paid to holders of common shares have been designated as "eligible dividends" for Canadian tax purposes.

During 2008, we received approval from the Toronto Stock Exchange (TSX) for a Normal Course Issuer Bid to repurchase up to a maximum of 52,914,046 common shares between August 6, 2008 and August 5, 2009. Under this authorization, we repurchased and cancelled 12,136,900 common shares acquired on the open market through the TSX in 2008 at an average price of $27.85 per common share, totalling $338 million. Of the amount paid, $22 million reduced the book value of our common shares and the excess of $316 million reduced retained earnings. We did not repurchase any common shares in 2010 or 2009.

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(C) TANDEM OPTIONS

In 2010, our board of directors approved amendments to our tandem option plans to allow for performance vesting of certain grants. Performance tandems vest over three years if our annual total shareholder return (stock price appreciation and cumulative dividends on a reinvested basis) falls within certain percentile ranks relative to our industry peer group. The ultimate number of performance tandems that vest will depend upon our performance measured over three calendar years. If our performance is below the specified level compared with our industry peer group, the performance tandems awarded will be forfeited. If our performance is at or above the specified level, the number of performance tandems exercisable shall be determined by our relative ranking. Stock compensation expense related to the performance tandems is accrued based on the price of our common shares at the end of the period and the anticipated performance factor. The expense is recognized over a three-year graded vesting period similar to the existing tandems plan.

We grant tandem and performance tandem options to purchase common shares to officers and employees. Performance tandems are awarded to officers and senior employees. Each option permits the right to either purchase one Nexen common share at the exercise price or receive a cash payment equal to the excess of market price over the exercise price. There were no performance tandems exercised during the year ended December 31, 2010. The following tandem options have been granted:

| | 2010 | | 2009 | | 2008 | |
|---|---|---|---|---|---|---|
| (thousands of shares) | Options (thousands) | Weighted Average Exercise Price ($/option) | Options (thousands) | Weighted Average Exercise Price ($/option) | Options (thousands) | Weighted Average Exercise Price ($/option) |
| Outstanding Tandem Options, Beginning of Year | 23,130 | 25 | 24,622 | 22 | 27,403 | 20 |
| Granted | 4,615 [1] | 22 | 4,350 | 24 | 3,534 | 19 |
| Exercised for Stock | (527) | 9 | (1,146) | 10 | (1,911) | 13 |
| Surrendered for Cash | (2,191) | 11 | (4,116) | 12 | (3,839) | 13 |
| Cancelled | (2,704) | 28 | (560) | 28 | (552) | 30 |
| Expired | (3,888) | 27 | (20) | 12 | (13) | 11 |
| End of Year | 18,435 | 25 | 23,130 | 25 | 24,622 | 22 |
| Tandem Options Exercisable at End of Year | 9,949 | 27 | 15,282 | 25 | 17,087 | 21 |
| Common Shares Reserved for Issuance Under the Tandem Option Plan | 25,301 | | 26,283 | | 27,429 | |

1 Approximately 29% of options granted in 2010 contain performance vesting conditions.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

The range of exercise prices of tandem and performance tandem options outstanding and exercisable at December 31, 2010 is as follows:

| | Outstanding Tandem and Performance Tandem Options | | | Exercisable Tandem and Performance Tandem Options | |
|---|---|---|---|---|---|
| | Number of Options (thousands) | Weighted Average Exercise Price ($/option) | Weighted Average Years to Expiry (years) | Number of Options (thousands) | Weighted Average Exercise Price ($/option) |
| $15.00 to $19.99 | 3,027 | 19 | 3 | 1,924 | 19 |
| $20.00 to $24.99 | 8,613 | 23 | 4 | 1,427 | 25 |
| $25.00 to $29.99 | 3,620 | 28 | 2 | 3,428 | 28 |
| $30.00 to $34.99 | 3,150 | 32 | 1 | 3,147 | 32 |
| $35.00 to $39.99 | 20 | 36 | 1 | 20 | 36 |
| $40.00 to $44.99 | 5 | 40 | 2 | 3 | 40 |
| Total | 18,435 | | | 9,949 | |

(D) STOCK APPRECIATION RIGHTS

In 2010, our board of directors approved amendments to our STARs plans to allow for performance vesting of certain grants. Performance STARs vest over three years if our annual total shareholder return (stock price appreciation and cumulative dividends on a reinvested basis) falls within certain percentile ranks relative to our industry peer group. The ultimate number of performance STARs that vest will depend upon our performance measured over three calendar years. If our performance is below the specified level compared with our industry peer group, the performance STARs awarded will be forfeited. If our performance is at or above the specified level, the number of performance STARs exercisable shall be determined by our relative ranking. Stock compensation expense related to the performance STARs is accrued based on the price of our common shares at the end of the period and the anticipated performance factor. The expense is recognized over a three-year graded vesting period similar to the existing STARs plan.

Our STARs and performance STARs plans entitle employees to cash payments equal to the excess of the market price of the common shares over the exercise price of the right. Performance STARs are awarded to senior employees. There were no performance STARs exercised during the year ended December 31, 2010. The following stock appreciation and performance stock appreciation rights have been granted:

| | 2010 | | 2009 | | 2008 | |
|---|---|---|---|---|---|---|
| (thousands of shares) | STARs (thousands) | Weighted Average Exercise Price ($/STAR) | STARs (thousands) | Weighted Average Exercise Price ($/STAR) | STARs (thousands) | Weighted Average Exercise Price ($/STAR) |
| Outstanding STARs | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Beginning of Year | 19,480 | | 25 | 16,986 | | 25 | 15,435 | | 24 |
| Granted | 3,354 | 1 | 22 | 5,273 | | 25 | 4,917 | | 19 |
| Exercised for Cash | (444 | ) | 16 | (2,079 | ) | 13 | (2,837 | ) | 15 |
| Cancelled | (1,806 | ) | 27 | (700 | ) | 28 | (529 | ) | 31 |
| Expired | (1,591 | ) | 27 | – | | – | – | | – |
| End of Year | 18,993 | | 25 | 19,480 | | 25 | 16,986 | | 25 |
| STARs Exercisable at End of Year | 10,938 | | 26 | 9,812 | | 28 | 8,119 | | 25 |

1Approximately 9% of STARs granted in 2010 contain performance vesting conditions.

The range of exercise prices of STARs outstanding at December 31, 2010 is as follows:

| | Outstanding STARs and Performance STARs | | | Exercisable STARs and Performance STARs | |
|---|---|---|---|---|---|
| | Number of STARs (thousands) | Weighted Average Exercise Price ($/STAR) | Weighted Average Years to Expiry (years) | Number of STARs (thousands) | Weighted Average Exercise Price ($/STAR) |
| $10.00 to $14.99 | 17 | 14 | 3 | 9 | 14 |
| $15.00 to $19.99 | 4,079 | 18 | 3 | 2,661 | 18 |
| $20.00 to $24.99 | 8,261 | 24 | 4 | 1,674 | 25 |
| $25.00 to $29.99 | 3,606 | 28 | 2 | 3,581 | 28 |
| $30.00 to $34.99 | 2,957 | 32 | 1 | 2,952 | 32 |
| $35.00 to $39.99 | 71 | 37 | 2 | 60 | 37 |
| $40.00 to $44.99 | 2 | 40 | 3 | 1 | 40 |
| Total | 18,993 | | | 10,938 | |

(E) RESTRICTED SHARE UNITS

In 2010, we adopted our restricted share unit plan (RSUs). RSUs are issued to eligible employees and permit the holder to receive cash payment equal to the market value of the stock on the vesting date. Market price on the vesting date is based on the volume weighted-average closing price during the 20 days prior to the end of the vesting period. RSUs do not have voting rights as there are no shares underlying the plans. A RSU is a notional entry that tracks the value of one Nexen common share. When cash dividends are paid on our common shares, eligible employees are credited RSUs equal to the dividend. All RSUs vest evenly over three years and are exercised and paid as they vest. For employees eligible to retire during the vesting period, the vesting period is accelerated to the retirement date. Obligations are revalued each period based on the market value of our common shares and the number of graded vesting RSUs outstanding.

| | Number (thousands) | Weighted Average Remaining Time to Expiry (years) | Weighted Average Fair Value ($/unit) |
|---|---|---|---|
| Outstanding at December 31, 2010 and Expected to Vest | 925 | 2 | 23 |

There were no RSUs that vested and settled during the year ended December 31, 2010. As at December 31, 2010, we had $18 million of unrecognized compensation expense related to RSUs, which we expect to recognize over a weighted-average period of 1.9 years.

## 15. COMMITMENTS, CONTINGENCIES AND GUARANTEES

We assume various contractual obligations and commitments in the normal course of our operations. Our operating leases, transportation, storage and drilling rig commitments as at December 31, 2010 are comprised of the following:

| | 2011 | 2012 | 2013 | 2014 | 2015 | Thereafter |
|---|---|---|---|---|---|---|
| Operating Leases | 98 | 84 | 79 | 56 | 28 | 78 |
| Transportation and Storage Commitments | 134 | 108 | 88 | 50 | 25 | 30 |
| Drilling Rig Commitments | 353 | 395 | 135 | 31 | – | – |

During 2010, total rental expense under operating leases was $62 million (2009 – $62 million; 2008 – $59 million).

We have a number of lawsuits and claims pending, including income tax reassessments (see Note 17), for which we currently cannot determine the ultimate result. We record costs as they are incurred or become determinable. We believe the resolution of these matters would not have a material adverse effect on our liquidity, consolidated financial position or results of operations.

From time to time, we enter into contracts that require us to indemnify parties against certain types of possible third-party claims, particularly when these contracts relate to divestiture transactions. On occasion, we may provide routine indemnifications. The terms of such obligations vary and, generally, a maximum is not explicitly stated. Because the obligations in these agreements are often not explicitly stated, the overall maximum amount of the obligations cannot be reasonably estimated. Historically, we have not been obligated to make significant payments for these obligations. We believe that payments, if any, related to existing indemnities would not have a material adverse effect on our liquidity, financial condition or results of operations.

## 16. MARKETING AND OTHER INCOME

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Marketing Revenue, Net (Note 6) | 334 | 943 | 467 |
| Long Lake Purchased Bitumen Sales | 85 | – | – |
| Change in Fair Value of Crude Oil Put Options (Note 6) | (41) | (251) | 203 |
| Interest | 7 | 7 | 28 |
| Foreign Exchange Gains (Losses) | (14) | 128 | 128 |
| Other | 44 | 32 | 37 |
| Total | 415 | 859 | 863 |

## 17. INCOME TAXES

### (A) TEMPORARY DIFFERENCES

| | 2010 | | 2009 | |
|---|---|---|---|---|
| | Future | Future Income Tax | Future | Future Income Tax |

| | Income Tax Assets | Liabilities | Income Tax Assets | Liabilities |
|---|---|---|---|---|
| Property, Plant and Equipment, Net | 32 | 3,125 | 36 | 2,762 |
| Tax Losses Carried Forward | 1,632 | – | 1,092 | – |
| Deferred Income | – | 13 | – | 49 |
| Recoverable Taxes | 14 | – | 20 | – |
| Total | 1,678 | 3,138 | 1,148 | 2,811 |

(B) CANADIAN AND FOREIGN PROVISION FOR INCOME TAXES

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Income (Loss) from Continuing Operations before Income Taxes | | | |
| Canadian | (847) | (542) | (252) |
| Foreign | 1,973 | 1,300 | 3,268 |
| | 1,126 | 758 | 3,016 |
| Provision for Income Taxes | | | |
| Current | | | |
| Canadian | – | 1 | 1 |
| Foreign | 1,127 | 772 | 856 |
| | 1,127 | 773 | 857 |
| Future | | | |
| Canadian | (190) | (166) | (19) |
| Foreign | (383) | (361) | 576 |
| | (573) | (527) | 557 |
| Total | 554 | 246 | 1,414 |

The Canadian and foreign components of the provision for income taxes are based on the jurisdiction in which income is taxed. Foreign taxes relate mainly to the United Kingdom, Yemen, Norway, Colombia and the United States.

(C)RECONCILIATION OF EFFECTIVE TAX RATE TO THE CANADIAN STATUTORY TAX RATE

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Income from Continuing Operations before Provision for Income Taxes | 1,126 | 758 | 3,016 |
| Provision for Income Taxes Computed at the Canadian Statutory Rate | 283 | 191 | 845 |
| Add (Deduct) the Tax Effect of: | | | |
| Foreign Tax Rate Differential | 251 | 96 | 530 |
| Higher (Lower) Tax Rates on Capital Gains | 1 | (42) | 9 |
| Federal and Provincial Capital Tax | 1 | 1 | 2 |
| Effect of Changes in Tax Rates | – | (22) | – |
| Non-Deductible Expenses and Other | 18 | 22 | 28 |
| Provision for Income Taxes | 554 | 246 | 1,414 |
| Effective Tax Rate | 49% | 32% | 47% |

(D) AVAILABLE UNUSED TAX LOSSES AND TAX CONTINGENCIES

At December 31, 2010, we had unused tax losses totalling $6,356 million (2009 – $4,219 million; 2008 – $954 million). The majority of these losses are in Canada and the United States and will expire between 2015 and 2030.

Nexen's income tax filings are subject to audit by taxation authorities. There are audits in progress and items under review, some of which may increase our tax liability. In addition, we have filed notices of objection with respect to certain issues. While the results of these items cannot be ascertained at this time, we believe we have an appropriate provision for income taxes based on available information.

## 18. DISPOSITIONS

Canadian Heavy Oil

In May 2010, we signed an agreement to sell our heavy oil properties in Canada. The sale closed in July 2010. We received proceeds of $939 million, net of closing adjustments and realized a gain of $781 million in the third quarter. The gain on sale and results of operations of these properties for the last three years have been presented as discontinued operations in Note 20.

Natural Gas Energy Marketing

During the third quarter of 2010, we sold our North American natural gas marketing operations. The sale, which generated proceeds of $9 million, closed in the third quarter and we recognized a non-cash loss on disposition of $259 million. The purchaser acquired our North American natural gas storage and transportation commitments, natural gas inventory, and related financial and physical derivative positions. As is customary with such transactions, not all contracts could be assigned to the purchaser by the closing date. We have a total return swap in place with the purchaser to transfer to them the economic results on the unassigned contracts until they are assigned to the purchaser. The total return swap and unassigned contracts are derivative instruments carried at fair value on our balance sheet. The related gains and losses offset each other for the current and future periods.

In connection with our natural gas energy marketing disposition, we assigned substantially all of our natural gas transportation and storage contracts, reducing our future commitments by $342 million. We agreed to maintain our parental guarantee to the pipeline provider related to one transportation commitment. We are obligated to perform under the guarantee only if the purchaser does not meet its obligation to the pipeline provider. To guarantee its performance, the purchaser provided us with cash collateral of US$43 million for the maximum exposure under the guarantee at that time. This collateral is included in accounts payable. We expect to cancel this guarantee in the first quarter of 2011.

North Dakota/Montana Crude Oil Marketing

During the fourth quarter of 2010, we sold our oil lease gathering, pipelines and storage assets in North Dakota and Montana for proceeds of $201 million. The sale closed in December 2010 and we recognized a gain on disposition of $121 million in the fourth quarter.

Canadian Undeveloped Oil SandsLeases

During the second quarter of 2010, we sold non-core lands in the Athabasca region for proceeds of $81 million. We had no plans to develop these lands for at least a decade. We recognized a gain on disposition of $80 million.

UK Undeveloped Lease

During the fourth quarter of 2010, we sold non-core lands in the UK North Sea for proceeds of $17 million. We had no plans to develop these leases. We recognized a gain on disposition of $17 million in the fourth quarter.

European Gas and Power Marketing

During the first quarter of 2010, we sold our European Gas and Power marketing business for cash proceeds of $15 million. There was no gain or loss on the disposition.

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## 19. SUBSEQUENT EVENTS

In early 2011, we completed the sale of our 62.7% investment in Canexus Limited Partnership, which operates the chemicals business, for net proceeds of $458 million. In the fourth quarter of 2010, we received board approval to sell our interest in Canexus and classified the assets and liabilities as held for sale at December 31, 2010. The results of our chemical business have been presented as discontinued operations for the last three years.

## 20. DISCONTINUED OPERATIONS

The results of operations of our Canadian heavy oil properties, disposed of during the year and our chemicals business, disposed of in early 2011, are detailed below and shown as discontinued operations in our Consolidated Statement of Income.

| | 2010 | | | 2009 | | | 2008 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Canada | Chemicals | Total | Canada | Chemicals | Total | Canada | Chemicals | Total |
| Revenues and Other Income | | | | | | | | | |
| Net Sales | 138 | 456 | 594 | 234 | 458 | 692 | 371 | 477 | 848 |
| Other | – | 25 | 25 | – | 50 | 50 | – | (50) | (50) |
| Gain on Disposition (Note 18) | 781 | – | 781 | – | – | – | – | – | – |
| | 919 | 481 | 1,400 | 234 | 508 | 742 | 371 | 427 | 798 |
| Expenses | | | | | | | | | |
| Operating | 50 | 308 | 358 | 97 | 267 | 364 | 114 | 297 | 411 |
| Depreciation, Depletion, Amortization and Impairment | 35 | 57 | 92 | 122 | 65 | 187 | 71 | 44 | 115 |
| Transportation and Other | 2 | 51 | 53 | 15 | 48 | 63 | 5 | 55 | 60 |
| General and Administrative | 10 | 33 | 43 | 21 | 42 | 63 | 14 | 33 | 47 |
| Exploration | – | – | – | – | – | – | 1 | – | 1 |
| Interest | – | 14 | 14 | – | 7 | 7 | – | 12 | 12 |
| | 97 | 463 | 560 | 255 | 429 | 684 | 205 | 441 | 646 |
| Income (Loss) before Provision for Income Taxes | 822 | 18 | 840 | (21) | 79 | 58 | 166 | (14) | 152 |
| Provision for (Recovery of) Income Taxes | | | | | | | | | |
| Current | – | 5 | 5 | – | 3 | 3 | – | 2 | 2 |
| Future | 206 | (1) | 205 | (4) | 15 | 11 | 41 | – | 41 |
| | 206 | 4 | 210 | (4) | 18 | 14 | 41 | 2 | 43 |
| Income (Loss) before Non-Controlling Interests | 616 | 14 | 630 | (17) | 61 | 44 | 125 | (16) | 109 |
| Less: Non-Controlling Interests | – | 5 | 5 | – | 20 | 20 | – | (4) | (4) |
| Net Income (Loss) from Discontinued Operations | 616 | 9 | 625 | (17) | 41 | 24 | 125 | (12) | 113 |

| | | | |
|---|---|---|---|
| Earnings Per Common Share | | | |
| Basic | 1.19 | 0.05 | 0.21 |
| Diluted | 1.19 | 0.05 | 0.21 |

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Assets and liabilities on the Consolidated Balance Sheet at December 31, 2009, include the following amounts for heavy oil discontinued operations in Canada. There were no assets and liabilities related to heavy oil discontinued operations in Canada at December 31, 2010.

| | 2010 | 2009 |
|---|---|---|
| Property, Plant and Equipment, Net of Accumulated DD&A | – | 331 |
| Asset Retirement Obligations | – | (116) |
| Deferred Credits and Other Liabilities | – | (29) |
| Total | – | 186 |

The following table provides the assets and liabilities that are associated with our chemicals business at December 31, 2010 and 2009.

| | 2010 | 2009 |
|---|---|---|
| Cash and Cash Equivalents | 3 | 14 |
| Accounts Receivable | 48 | 54 |
| Inventories and Supplies | 35 | 33 |
| Other Current Assets | 1 | 3 |
| Property, Plant and Equipment, Net of Accumulated DD&A | 643 | 573 |
| Future Income Tax Asset | 7 | 4 |
| Deferred Charges and Other Assets | 11 | 12 |
| Assets | 748 [1] | 693 |
| Accounts Payable and Accrued Liabilities | 56 | 67 |
| Accrued Interest Payable | 3 | – |
| Long-Term Debt[2] | 394 | 327 |
| Future Income Tax Liability | 39 | 35 |
| Asset Retirement Obligations | 41 | 47 |
| Deferred Credits and Other Liabilities | 7 | 5 |
| Liabilities | 540 [1] | 481 |
| Equity – Canexus Non-Controlling Interest | 84 | 64 |

[1] Included in assets and liabilities held for sale at December 31, 2010.

[2] Long-term debt included in chemicals liabilities held for sale at December 31, 2010, comprised of:

Term credit facilities of $273 million, available until August 2012, with interest payable monthly at variable rates;

US$50 million notes, repayable in May 2013, with interest payable quarterly at 6.57%;

Convertible debentures of $22 million, maturing December 2014, with interest payable semi-annually at 8% convertible at the holders option subject to certain conditions; and

Convertible debentures of $49 million, maturing December 2015, with interest payable semi-annually at 5.75%, convertible at the holders option subject to certain conditions.

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## 21. EARNINGS PER SHARE

We calculate basic earnings per common share using net income divided by the weighted-average number of common shares outstanding. We calculate diluted earnings per common share in the same manner as basic, except we use the weighted-average number of diluted common shares outstanding in the denominator.

| (millions of shares) | 2010 | 2009 | 2008 |
|---|---|---|---|
| Weighted-Average Number of Common Shares, Basic | 524.7 | 521.4 | 526.1 |
| Shares Issuable Pursuant to Tandem Options | 5.7 | 10.1 | 18.8 |
| Shares to be Notionally Purchased from Proceeds of Tandem Options | (4.7) | (7.0) | (12.7) |
| Weighted-Average Number of Common Shares, Diluted | 525.7 | 524.5 | 532.2 |

In calculating the weighted-average number of diluted common shares outstanding for the year ended December 31, 2010, we excluded 15,432,784 tandem options (2009 – 13,485,465; 2008 – 5,694,055) because their exercise price was greater than the annual average common share market price in those periods. During the last three years, outstanding tandem options were the only potential dilutive instruments.

## 22. CASH FLOWS

### (A) CHARGES AND CREDITS TO INCOME NOT INVOLVING CASH

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Depreciation, Depletion, Amortization and Impairment | 1,662 | 1,615 | 1,899 |
| Stock-Based Compensation | (41) | (10) | (272) |
| Net Loss (Gains) on Dispositions | 41 | – | – |
| Non-cash items included in Discontinued Operations | (499) | 149 | 210 |
| Provision for (Recovery of) Future Income Taxes | (573) | (527) | 557 |
| Change in Fair Value of Crude Oil Put Options | 41 | 251 | (203) |
| Foreign Exchange | 14 | (128) | (58) |
| Other | (5) | 21 | 7 |
| Total | 640 | 1,371 | 2,140 |

### (B) CHANGES IN NON-CASH WORKING CAPITAL

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Accounts Receivable | 96 | 92 | 950 |
| Inventories and Supplies | (105) | (236) | 246 |
| Other Current Assets | 47 | 9 | 5 |
| Accounts Payable and Accrued Liabilities | 241 | (23) | (1,232) |
| Other Current Liabilities | – | 23 | 26 |
| Total | 279 | (135) | (5) |
| Relating to: | | | |
| Operating Activities | 338 | (25) | 119 |
| Investing Activities | (59) | (110) | (124) |

| | | | |
|---|---|---|---|
| Total | 279 | (135) | (5) |

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(C) OTHER CASH FLOW INFORMATION

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Interest Paid | 380 | 335 | 319 |
| Income Taxes Paid | 951 | 483 | 1,055 |

Cash flow from other operating activities includes cash outflows related to geological and geophysical expenditures of $100 million (2009 – $81 million; 2008 – $137 million).

## 23. OPERATING SEGMENTS AND RELATED INFORMATION

Nexen has the following operating segments in various industries and geographic locations:

Oil and Gas: We explore for, develop and produce crude oil, natural gas and related products around the world. We manage our operations to reflect differences in the regulatory environments and risk factors for each country. Our core operations are onshore in Yemen and Canada, and offshore in the US Gulf of Mexico and the UK North Sea. Our other operations are primarily in Colombia, offshore West Africa and Norway. We also own 7.23% of Syncrude, which develops and produces synthetic crude oil from mining bitumen in the Athabasca oil sands in northern Alberta.

Energy Marketing: Our energy marketing group sells our crude oil and natural gas proprietary production and markets third-party crude oil, natural gas and power (including electricity generation). We use financial and derivative contracts, including futures, forwards, swaps and options for economic hedging and trading purposes. Our energy marketing group also uses physical commodity transportation and storage capacity contracts to capture regional crude oil opportunities. We sold a portion of our energy marketing business in 2010 (see Note 18).

Chemicals: Canexus manufactures, markets and distributes industrial chemicals, principally sodium chlorate, chlorine, muriatic acid and caustic soda. They produce sodium chlorate at three facilities in Canada and one in Brazil. They produce chlorine, caustic soda and muriatic acid at chloralkali facilities in Canada and Brazil. In early 2011, we disposed of our investment in Canexus as described in Note 19. As at December 31, 2010, these operations have been presented as held for sale and results of operations for the last three years have been included in discontinued operations (see Note 20). Our chemicals financial position and results of operations is included with Corporate, Chemicals and Other.

The accounting policies of our operating segments are the same as those described in Note 1. Net income of our operating segments excludes interest income, interest expense, unallocated corporate expenses and foreign exchange gains and losses. Identifiable assets are those used in the operations of the segments.

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2010 Operating and Geographic Segments

| (Cdn$ millions) | Oil and Gas | | | | | | Energy Marketing | Corporate, Chemicals and Other | Total |
|---|---|---|---|---|---|---|---|---|---|
| | United Kingdom | Canada[1] | Syncrude | United States | Yemen | Other Countries[2] | | | |
| Net Sales[3] | 3,115 | 503 | 580 | 424 | 696 | 54 | 39 | – | 5,411 |
| Marketing and Other | 17 | 87 | 5 | 1 | 16 | – | 334 | (45 )[4] | 415 |
| | 3,132 | 590 | 585 | 425 | 712 | 54 | 373 | (45 ) | 5,826 |
| Less: Expenses | | | | | | | | | |
| Operating | 335 | 442 | 284 | 97 | 158 | 5 | 33 | – | 1,354 |
| Depreciation, Depletion, Amortization and Impairment[5] | 827 | 259 | 53 | 343 | 112 | 9 | 18 | 41 | 1,662 |
| Transportation and Other | 2 | 201 | 21 | 2 | 26 | 1 | 314 | (1 ) | 566 |
| General and Administrative[6] | 22 | 45 | 1 | 62 | 6 | 27 | 69 | 207 | 439 |
| Exploration | 67 | 42 | – | 115 | – | 104 [7] | – | – | 328 |
| Interest | – | – | – | – | – | – | – | 310 | 310 |
| Net (Gains) Loss on Disposition | (17 ) | (80 ) | – | – | – | – | 138 | – | 41 |
| Income (Loss) from Continuing Operations before Income Taxes | 1,896 | (319 ) | 226 | (194 ) | 410 | (92 ) | (199 ) | (602 ) | 1,126 |
| Less: Provision for (Recovery of) Income Taxes[8] | 834 | (80 ) | 57 | (67 ) | 143 | (83 ) | (78 ) | (172 ) | 554 |
| Income (Loss) from Continuing Operations | 1,062 | (239 ) | 169 | (127 ) | 267 | (9 ) | (121 ) | (430 ) | 572 |
| Add: Net Income from Discontinued Operations[9] | – | 590 | – | – | – | – | 26 | 9 | 625 |
| Net Income (Loss) | 1,062 | 351 | 169 | (127 ) | 267 | (9 ) | (95 ) | (421 ) | 1,197 |
| Identifiable Assets | 4,251 | 8,002 [10] | 1,339 | 1,662 | 248 | 1,412 [11] | 1,778 [12] | 3,215 [13] | 21,907 |
| Capital Expenditures Exploration and Development | 596 | 773 | 100 | 214 | 52 | 578 | 29 | 181 | 2,523 |
| Proved Property Acquisitions | 79 | – | – | – | – | – | – | – | 79 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Total | 675 | 773 | 100 | 214 | 52 | 578 | 29 | 181 | 2,602 |
| PP&E | | | | | | | | | |
| Cost | 6,610 | 8,729 | 1,545 | 3,913 | 2,379 | 1,362 | 195 | 397 | 25,130 |
| Less: Accumulated DD&A | 3,273 | 883 | 305 | 2,689 | 2,312 | 88 | 66 | 265 | 9,881 |
| Net Book Value3 | 3,337 | 7,846 10 | 1,240 | 1,224 | 67 | 1,274 11 | 129 | 132 | 15,249 |
| Goodwill14 | 277 | – | – | – | – | – | 9 | – | 286 |

1Includes results of operations from conventional, oil sands, shale gas and CBM.

2Includes results of operations from producing activities in Colombia.

3Net sales made from all segments originating in Canada: $1,122 million PP&E located in Canada: $9,347 million.

4Includes interest income of $7 million, foreign exchange losses of $14 million, decrease in the fair value of crude oil put options of $41 million and other gains of $3 million.

5Includes an impairment charge related to gas properties in the US Gulf of Mexico of $93 million.

6Includes net recovery of stock-based compensation expense of $14 million.

7Includes exploration activities primarily in Norway, Nigeria and Colombia.

8The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

9Discontinued operations are disclosed in Note 20.

10Includes $6,179 million related to our insitu oil sands (Long Lake and future phases).

11Includes $1,222 million related to our Usan development, offshore Nigeria.

1284% of marketing’s identifiable assets are accounts receivable and inventories.

13Includes $748 million of assets held for sale relating to our chemicals operations (see Note 20).

14Goodwill decreased in the UK by $15 million as a result of changes in foreign exchange rates. Goodwill decreased in energy marketing by $38 million as a result of our various dispositions and changes in foreign exchange rates.

2009 Operating and Geographic Segments

| (Cdn$ millions) | Oil and Gas | | | | | | Energy Marketing | Corporate, Chemicals and Other | Total |
|---|---|---|---|---|---|---|---|---|---|
| | United Kingdom | Canada | Syncrude | United States | Yemen | Other Countries[1] | | | |
| Net Sales[2] | 2,430 | 161 | 480 | 321 | 705 | 70 | 36 | – | 4,203 |
| Marketing and Other | 18 | 1 | 7 | – | 14 | 6 | 943 | (130)[3] | 859 |
| | 2,448 | 162 | 487 | 321 | 719 | 76 | 979 | (130) | 5,062 |
| Less: Expenses | | | | | | | | | |
| Operating | 253 | 74 | 265 | 98 | 191 | 8 | 27 | – | 916 |
| Depreciation, Depletion, Amortization and Impairment[4] | 875 | 179 | 63 | 312 | 102 | 14 | 27 | 43 | 1,615 |
| Transportation and Other | 17 | 12 | 28 | 22 | 30 | – | 599 | 24 | 732 |
| General and Administrative[5] | 18 | 46 | 1 | 60 | 6 | 35 | 91 | 177 | 434 |
| Exploration | 50 | 84 | – | 104 | – | 64[6] | – | – | 302 |
| Interest | – | – | – | – | – | – | – | 305 | 305 |
| Income (Loss) from Continuing Operations before Income Taxes | 1,235 | (233) | 130 | (275) | 390 | (45) | 235 | (679) | 758 |
| Less: Provision for (Recovery of) Income Taxes[7] | 487 | (60) | 33 | (95) | 141 | (23) | 96 | (333) | 246 |
| Add: Net Income from Discontinued Operations[8] | – | (17) | – | – | – | – | – | 41 | 24 |
| Net Income (Loss) | 748 | (190) | 97 | (180) | 249 | (22) | 139 | (305) | 536 |
| Identifiable Assets | 4,866 | 7,809[9] | 1,287 | 1,715 | 229 | 1,090 | 3,050[10] | 2,854 | 22,900 |
| Capital Expenditures | | | | | | | | | |
| Exploration and Development | 626 | 843 | 87 | 285 | 69 | 557 | 28 | 247 | 2,742 |
| Proved Property Acquisitions | – | 755 | – | – | – | – | – | – | 755 |
| Total | 626 | 1,598 | 87 | 285 | 69 | 557 | 28 | 247 | 3,497 |
| PP&E | | | | | | | | | |
| Cost | 6,115 | 9,664 | 1,463 | 3,900 | 2,462 | 930 | 259 | 1,506 | 26,299 |
| Less: Accumulated DD&A | 2,664 | 2,038 | 270 | 2,529 | 2,322 | 99 | 83 | 802 | 10,807 |
| Net Book Value[2] | 3,451 | 7,626[9] | 1,193 | 1,371 | 140 | 831 | 176 | 704 | 15,492 |
| Goodwill[11] | 292 | – | – | – | – | – | 47 | – | 339 |

1Includes results of operations from producing activities in Colombia.

2Net sales made from all segments originating in Canada: $1,063 million PP&E located in Canada: $9,610 million

3Includes interest income of $7 million, foreign exchange gains of $128 million, decrease in the fair value of crude oil put options of $251 million and other losses of $14 million.

4Includes an impairment charge related to gas properties in Canada and the US Gulf of Mexico of $58 million and $20 million, respectively.

5Includes stock-based compensation expense of $69 million.

6Includes exploration activities primarily in Norway, Nigeria and Colombia.

7The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

8Discontinued operations are disclosed in Note 20.

9Includes $6,045 million related to our insitu oil sands (Long Lake and future phases).

1078% of marketing's identifiable assets are accounts receivable and inventories.

11Goodwill decreased in the UK and energy marketing by $49 million and $2 million, respectively, as a result of changes in foreign exchange rates.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

2008 Operating and Geographic Segments

| (Cdn$ millions) | Oil and Gas United Kingdom | Canada | Syncrude | United States | Yemen | Other Countries[1] | Energy Marketing | Corporate, Chemicals and Other | Total |
|---|---|---|---|---|---|---|---|---|---|
| Net Sales[2] | 3,580 | 285 | 691 | 665 | 1,093 | 192 | 70 | – | 6,576 |
| Marketing and Other | 5 | 3 | 6 | 4 | 12 | – | 467 | 366 [3] | 863 |
| | 3,585 | 288 | 697 | 669 | 1,105 | 192 | 537 | 366 | 7,439 |
| Less: Expenses | | | | | | | | | |
| Operating | 253 | 68 | 280 | 94 | 176 | 10 | 43 | – | 924 |
| Depreciation, Depletion, Amortization and Impairment[4] | 999 | 137 | 49 | 475 | 160 | 17 | 19 | 43 | 1,899 |
| Transportation and Other | 19 | 7 | 16 | 3 | 9 | – | 805 | 48 | 907 |
| General and Administrative[5] | (8) | 6 | 1 | 38 | (7) | 13 | 79 | 88 | 210 |
| Exploration | 86 | 78 | – | 109 | 5 | 123 [6] | – | – | 401 |
| Interest | – | – | – | – | – | – | – | 82 | 82 |
| Income (Loss) from Continuing Operations before Income Taxes | 2,236 | (8) | 351 | (50) | 762 | 29 | (409) | 105 | 3,016 |
| Less: Provision for (Recovery of) Income Taxes[7] | 1,126 | 4 | 99 | (19) | 264 | (4) | (102) | 46 | 1,414 |
| Add: Net Income from Discontinued Operations[8] | – | 125 | – | – | – | – | – | (12) | 113 |
| Net Income (Loss) | 1,110 | 113 | 252 | (31) | 498 | 33 | (307) | 47 | 1,715 |
| Identifiable Assets | 6,632 | 6,643 [9] | 1,198 | 2,044 | 342 | 701 | 3,280 [10] | 1,315 | 22,155 |
| Capital Expenditures Exploration and Development | 691 | 1,405 | 55 | 405 | 101 | 238 | 8 | 141 | 3,044 |
| Proved Property Acquisitions | – | 22 | – | – | – | – | – | – | 22 |
| Total | 691 | 1,427 | 55 | 405 | 101 | 238 | 8 | 141 | 3,066 |
| PP&E | | | | | | | | | |
| Cost | 6,532 | 8,134 | 1,372 | 4,398 | 2,808 | 554 | 246 | 1,271 | 25,315 |
| Less: Accumulated DD&A | 2,159 | 1,786 | 236 | 2,702 | 2,610 | 113 | 76 | 711 | 10,393 |
| Net Book Value[2] | 4,373 | 6,348 [9] | 1,136 | 1,696 | 198 | 441 | 170 | 560 | 14,922 |
| Goodwill | 341 | – | – | – | – | – | 49 | – | 390 |

1Includes results of operations from producing activities in Colombia.

2Net sales made from all segments originating in Canada: $1,570 million PP&E located in Canada: $8,121 million

3Includes interest income of $28 million, foreign exchange gains of $128 million, increase in the fair value of crude oil put options of $203 million and other income of $7 million.

4Includes an impairment charge related to oil and gas properties in the UK North Sea and the US Gulf of Mexico of $318 million and $250 million, respectively.

5Includes recovery of stock-based compensation expense of $160 million.

6Includes exploration activities primarily in Norway, Nigeria and Colombia.

7The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

8Discontinued operations are disclosed in Note 20.

9Includes $4,742 million related to our insitu oil sands (Long Lake and future phases).

1079% of marketing's identifiable assets are accounts receivable and inventories.

24.DIFFERENCES BETWEEN CANADIAN AND US GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Consolidated Financial Statements have been prepared in accordance with Canadian GAAP. US GAAP Consolidated Financial Statements and summaries of differences from Canadian GAAP are as follows:

Consolidated Statement of Income – US GAAP for the Three Years Ended December 31, 2010

| (Cdn$ millions, except per-share amounts) | 2010 | 2009 | 2008 |
|---|---|---|---|
| Revenues and Other Income | | | |
| Net Sales | 5,411 | 4,203 | 6,576 |
| Marketing and Other (v) | 449 | 847 | 846 |
| | 5,860 | 5,050 | 7,422 |
| Expenses | | | |
| Operating | 1,354 | 916 | 924 |
| Depreciation, Depletion, Amortization and Impairment | 1,662 | 1,615 | 1,899 |
| Transportation and Other | 566 | 732 | 904 |
| General and Administrative (iv) | 435 | 469 | 216 |
| Exploration | 328 | 302 | 401 |
| Interest | 310 | 305 | 82 |
| Net Loss from Dispositions | 41 | – | – |
| | 4,696 | 4,339 | 4,426 |
| | | | |
| Income from Continuing Operations before Provision for Income Taxes | 1,164 | 711 | 2,996 |
| Provision for (Recovery of) Income Taxes | | | |
| Current | 1,127 | 773 | 857 |
| Deferred (iv); (v) | (550) | (545) | 548 |
| | 577 | 228 | 1,405 |
| Net Income from Continuing Operations | 587 | 483 | 1,591 |
| Net Income from Discontinued Operations | 625 | 24 | 113 |
| Net Income – US GAAP1 | 1,212 | 507 | 1,704 |
| Earnings Per Common Share from Continuing Operations ($/share) (Note 21) | | | |
| Basic | 1.12 | 0.92 | 3.03 |
| Diluted | 1.11 | 0.92 | 2.99 |
| Earnings Per Common Share ($/share) (Note 21) | | | |
| Basic | 2.31 | 0.97 | 3.24 |
| Diluted | 2.30 | 0.97 | 3.20 |

1Reconciliation of Canadian and US GAAP Net Income.

| (Cdn$ millions) | 2010 | 2009 | 2008 |
|---|---|---|---|
| Net Income – Canadian GAAP | 1,197 | 536 | 1,715 |
| Impact of US Principles, Net of Income Taxes: | | | |
| Stock-based Compensation (iv) | (8) | (26) | (4) |
| Inventory Valuation (v) | 23 | (10) | (7) |
| Deferred Taxes (vi) | -- | 7 | -- |
| | | | |
| Net Income – US GAAP | 1,212 | 507 | 1,704 |

Consolidated Balance Sheet – US GAAP December 31, 2010 and 2009

| (Cdn$ millions, except per-share amounts) | 2010 | 2009 |
|---|---|---|
| ASSETS | | |
| Current Assets | | |
| Cash and Cash Equivalents | 1,005 | 1,700 |
| Restricted Cash | 40 | 198 |
| Accounts Receivable | 1,938 | 2,788 |
| Inventories and Supplies (v) | 513 | 610 |
| Other | 142 | 185 |
| Assets Held for Sale | 748 | – |
| Total Current Assets | 4,386 | 5,481 |
| Property, Plant and Equipment | | |
| Net of Accumulated Depreciation, Depletion, Amortization and | | |
| Impairment of $10,274 (December 31, 2009 – $11,200) (i); (iii) | 15,200 | 15,443 |
| Goodwill | 286 | 339 |
| Deferred Income Tax Assets | 1,678 | 1,148 |
| Deferred Charges and Other Assets | 272 | 370 |
| TOTAL ASSETS | 21,822 | 22,781 |
| LIABILITIES | | |
| Current Liabilities | | |
| Accounts Payable and Accrued Liabilities (iv) | 2,634 | 3,131 |
| Accrued Interest Payable | 83 | 89 |
| Dividends Payable | 26 | 26 |
| Liabilities Held for Sale | 540 | – |
| Total Current Liabilities | 3,283 | 3,246 |
| Long-Term Debt | 5,079 | 7,251 |
| Deferred Income Tax Liabilities (i); (ii); (iv); (v); (vi) | 3,054 | 2,720 |
| Asset Retirement Obligations | 1,009 | 1,018 |
| Deferred Credits and Other Liabilities (ii) | 852 | 1,126 |
| Equity | | |
| Nexen Inc. Shareholders' Equity Common Shares, no par value | | |
| Authorized: Unlimited Outstanding: 2010 – 525,706,403 shares | | |
| 2009 – 522,915,843 shares | 1,111 | 1,049 |
| Contributed Surplus | – | 1 |
| Retained Earnings (i); (iii); (iv); (v); (vi) | 7,683 | 6,575 |
| Accumulated Other Comprehensive Loss (ii) | (333) | (269) |
| Total Nexen Inc. Shareholders' Equity | 8,461 | 7,356 |
| Canexus Non-Controlling Interest | 84 | 64 |
| Total Equity | 8,545 | 7,420 |
| Commitments, Contingencies and Guarantees | | |
| TOTAL LIABILITIES AND EQUITY | 21,822 | 22,781 |

Consolidated Statement of Comprehensive Income – US GAAP For the Three Years ended December 31, 2010

| (Cdn$ millions) | 2010 | 2009 | 2008 |
|---|---|---|---|
| Net Income – US GAAP | 1,212 | 507 | 1,704 |
| Other Comprehensive Income (Loss), Net of Income Taxes: | | | |
| Foreign Currency Translation Adjustment | (29) | (56) | 159 |
| Change in Mark to Market on Cash Flow Hedges | – | – | – |
| Unamortized Defined Benefit Pension Plan Costs (ii) | (35) | (4) | (21) |
| Comprehensive Income – US GAAP | 1,148 | 447 | 1,842 |

Consolidated Statement of Accumulated Other Comprehensive Loss – US GAAP December 31, 2010 and 2009

| (Cdn$ millions) | 2010 | 2009 |
|---|---|---|
| Foreign Currency Translation Adjustment | (219) | (190) |
| Unamortized Defined Benefit Pension Plan Costs (ii) | (114) | (79) |
| Accumulated Other Comprehensive Loss (AOCL) | (333) | (269) |

Notes to the Consolidated US GAAP Financial Statements

We have not included a US GAAP Consolidated Statement of Cash Flows as we have not identified any cash flow differences between Canadian and US GAAP.

i. Under Canadian GAAP, we defer certain development costs to PP&E. Under US GAAP, these costs have been included in operating expenses. As a result:

- PP&E is lower under US GAAP by $30 million and deferred income tax liabilities are $11 million lower.

ii. US GAAP requires the recognition of the over-funded and under-funded status of defined benefit pension plans on the balance sheet as an asset or liability. At year end, the unfunded amount of our defined benefit pension plans that was not included in the pension liability under Canadian GAAP was $156 million (2009 – $105 million). This amount has been included in deferred credits and other liabilities, and $114 million, net of income taxes (2009 – $79 million, net of income taxes) has been included in accumulated other comprehensive income. Deferred income tax liabilities are $42 million lower (2009 – lower by $26 million).

iii. On January 1, 2003, we adopted Accounting for Asset Retirement Obligations for US GAAP reporting purposes. We adopted the equivalent Canadian standard for asset retirement obligations on January 1, 2004. These standards are consistent, except for the adoption date, which resulted in our PP&E under US GAAP being lower by $19 million.

iv. Under Canadian principles, we record obligations for liability-based stock compensation plans using the intrinsic-value method of accounting. Under US principles, obligations for liability-based stock compensation plans are recorded using the fair-value method of accounting. As a result:

- general and administrative expense is lower by $4 million (higher by $8 million, net of income taxes) for the year ended December 31, 2010 (2009 – higher by $35 million ($26 million, net of income taxes); 2008 – higher by $6 million ($4 million, net of income taxes)); and

- accounts payable and accrued liabilities are higher by $89 million at December 31, 2010 (2009 – higher by $93 million) and deferred income tax liabilities are $14 million lower (2009 – lower by $26 million).

v. Under Canadian GAAP, we carry our commodity inventory held for trading purposes at fair value, less any costs to sell. Under US GAAP, we are required to carry this inventory at the lower of cost or net realizable value. As a result marketing and other income is higher by $34 million ($23 million, net of income taxes) for the year ended December 31, 2010 (2009 – lower by $12 million, ($10 million, net of income taxes); 2008 – lower by $14 million ($7 million, net of income taxes)); and inventories are lower by $36 million at December 31, 2010 (2009 – lower by $70 million) and deferred income tax liabilities are $12 million lower (2009 – lower by $23 million).

vi. Under US GAAP, we are required to apply Accounting Standards Codification (ASC) Topic 740 Accounting for Uncertainty in Income Taxes regarding accounting and disclosure for uncertain tax positions. As at December 31, 2010, the total amount of our unrecognized tax benefits was approximately $291 million, all of which, if recognized, would affect our effective tax rate. To the extent interest and penalties may be assessed by taxing authorities on any underpayment of income tax, such amounts have been accrued and are classified as a component of income taxes in the Consolidated Statement of Income. As at December 31, 2010, the total amount of interest and penalties related to uncertain tax positions recognized in deferred income tax liabilities in the US GAAP – Consolidated Balance Sheet was approximately $10 million. We had no interest or penalties included in the US GAAP – Consolidated Statement of Income for the year ended December 31, 2010.

Our income tax filings are subject to audit by taxation authorities and as at December 31, 2010, the following tax years remained subject to examination: (i) Canada – 1985 to date; (ii) United Kingdom – 2008 to date; and (iii) United States – 2005 to date. We do not anticipate any material changes to the unrecognized tax benefits previously disclosed within the next 12 months.

Reconciliation of Unrecognized Tax Benefits

(Cdn$ millions)

| | |
|---|---|
| Balance at January 1, 2010 | 277 |
| Additions for tax positions related to the current year | 19 |
| Additions for tax positions related to prior years | 26 |
| Reductions for tax positions related to prior years | (31) |
| Balance at December 31, 2010 | 291 |

US GAAP Stock-Based Compensation

Under US GAAP, our stock-based compensation expense is accounted for by applying ASC Topic 718 Compensation–Stock Compensation. Under this guidance, our tandem options, performance tandem options, stock appreciation rights, performance stock appreciation rights, and restricted share units are considered liability-based stock compensation plans. Obligations for liability-based stock compensation plans are measured at the estimated fair value and remeasured in each subsequent reporting period.

Assumptions

We use the Generalized Black-Scholes option pricing model to estimate the fair value of TOPs and STARs. The following assumptions are made:

| | |
|---|---|
| Expected Annual Dividends per Common Share ($/share) | 0.20 |
| Expected Volatility | 56% |
| Risk-Free Interest Rate | 1.6% – 2.6% |
| Weighted-Average Expected Life of Compensation Instruments (years) | 3.1 – 3.3 |

These assumptions are based on multiple factors, including historical exercise patterns of employees in relatively homogenous groups with respect to exercise and post-vesting employment termination behaviors, expected future exercising patterns for those same homogenous groups, the historical volatility of our stock price, our expected future dividend levels and the interest rate for Government of Canada bonds.

We use the Monte Carlo option pricing model to simulate expected returns and estimate the fair value of our Performance TOPs and Performance STARs. The model simulates our expected total shareholder return relative to our industry peer group. This is applied to the reward criteria of the performance TOPs and STARs to give an expected value at the measurement date. The assumptions used in the Monte Carlo option pricing model are similar to those used in the Generalized Black-Scholes option pricing model, only the Monte Carlo option pricing model assumes a risk-free interest rate of 1.87%.

Tandem Options

| | Number (thousands) | Weighted Average Exercise Price ($/option) | Weighted Average Remaining Term to Expiry (years) | Aggregate Intrinsic Value (Cdn$ millions) | Weighted Average Fair Value ($/option) |
|---|---|---|---|---|---|
| Outstanding at December 31, 2010 | 18,435 | 25 | 3.1 | 15 | 5.42 |
| Outstanding at December 31, 2010 and Expected to Vest | 17,907 | 25 | 3.0 | 14 | 5.33 |
| Exercisable at December 31, 2010 | 9,949 | 27 | 2.0 | 7 | 3.14 |

The total intrinsic value of tandem options exercised during the year ended December 31, 2010 was $31 million (2009 – $66 million; 2008 – $88 million). There were no performance tandem options exercised during the year ended December 31, 2010. As at December 31, 2010, we had $47 million (2009 -$55 million) of unrecognized compensation expense related to tandem options, which we expect to recognize over a weighted-average period of 1.6 years (2009 -1.6 years).

Stock Appreciation Rights

| | Number (thousands) | Weighted Average Exercise Price ($/right) | Weighted Average Remaining Term to Expiry (years) | Aggregate Intrinsic Value (Cdn$ millions) | Weighted Average Fair Value ($/right) |
|---|---|---|---|---|---|
| Outstanding at December 31, 2010 | 18,993 | 25 | 3.0 | 20 | 5.29 |
| | 18,392 | 25 | 3.0 | 19 | 5.20 |

| | | | | | |
|---|---|---|---|---|---|
| Outstanding at December 31, 2010 and Expected to Vest | | | | | |
| Exercisable at December 31, 2010 | 10,938 | 26 | 2.1 | 12 | 3.38 |

The total intrinsic value of stock appreciation rights exercised during the year ended December 31, 2010 was $3 million (2009 – $26 million; 2008 – $52 million). There were no performance stock appreciation rights exercised during the year ended December 31, 2010. As at December 31, 2010, we had $40 million (2009 -$64 million) of unrecognized compensation expense related to stock appreciation rights, which we expect to recognize over a weighted-average period of 1.5 years (2009 -1.6 years).

Restricted Share Units

| | Number (thousands) | Weighted Average Remaining Term to Expiry (years) | Aggregate Intrinsic Value (Cdn$ millions) | Weighted Average Fair Value ($/right) |
|---|---|---|---|---|
| Outstanding at December 31, 2010 | 925 | 2.0 | 21 | 22.80 |
| Outstanding at December 31, 2010 and Expected to Vest | 839 | 2.0 | 19 | 22.80 |
| Exercisable at December 31, 2010 | – | – | – | – |

RSUs settle on each vesting date. There were no RSUs that vested and settled during the year ended December 31, 2010. As at December 31, 2010, we had $18 million of unrecognized compensation expense related to RSUs, which we expect to recognize over a weighted-average period of 1.9 years.

Stock-Based Compensation Expense and Payments

For the year ended December 31, 2010, stock-based compensation recovery of $18 million (2009 – $104 million recovery; 2008 – $154 million recovery) was included in general and administrative expense in the Consolidated Statement of Income – US GAAP.

For the year ended December 31, 2010, cash proceeds of $5 million were received related to the exercise of stock options (2009 – $12 million; 2008 – $23 million). For the year ended December 31, 2010, $29 million was paid related to the exercise of stock options and stock appreciation rights (2009 – $81 million; 2008 – $121 million). The income tax benefit recorded from the exercise of stock options and stock appreciation rights was $1 million (2009 – $20 million; 2008 – $34 million) for the period.

New Accounting Pronouncement – US GAAP

In January 2010, FASB issued guidance to improve financial instrument fair value measurement disclosures. The guidance requires entities to describe transfers between the three levels of the fair value hierarchy and present items separately in the Level 3 reconciliation. This guidance is consistent with fair value measurement disclosures adopted for Canadian GAAP in 2009. Adoption of this guidance did not have an impact on our results of operations or financial position.

## II.DIFFERENCES BETWEEN ACCOUNTING POLICIES ADOPTED BY THE COMPANY (IFRS AND HKFRS) AND NEXEN (CANADIAN GAAP OR IFRS)

As described in the section entitled "Letter from the Board – Waivers from Strict Compliance with the Listing Rules – Waiver from the Requirement to Prepare an Accountants' Report on Nexen", the Company has applied to the Hong Kong Stock Exchange for, and been granted, a waiver from the requirement to produce an accountants' report on Nexen Group in accordance with Rule 14.67(6)(a)(i) of the Listing Rules.

Instead, this circular contains a copy of the:

(a)Nexen 2010 Canadian GAAP Accounts with 2009 comparative financial statements audited by Deloitte Canada (the "Nexen 2009 Accounts"); and

(b)Nexen 2011 IFRS Accounts with 2010 comparative financial statements audited by Deloitte Canada and the unaudited condensed consolidated financial statements for the six months ended 30 June 2012 (together the "Nexen Post 2009 Accounts"),

(together the "Nexen Historical Track Record Accounts" as set out in Appendix II).

The Nexen Historical Track Record Accounts cover the financial positions of the Nexen Group as at 31 December 2009, 2010 and 2011 and 30 June 2012 and the results of the Nexen Group for each of the three years ended 31 December 2009, 2010 and 2011 and the six months ended 30 June 2012 (the "Relevant Periods").

The unaudited condensed consolidated financial statements of Nexen as at 30 June 2012 and for the six months ended 30 June 2012 with 2011 comparative figures were reviewed by Deloitte Canada, the independent auditor of Nexen, in accordance with Canadian generally accepted standards for a review of interim financial statements by an entity's auditor. Such an interim review consists principally of applying analytical procedures to financial data, and making enquiries of, and having discussions with, persons responsible for financial and accounting matters. An interim review is substantially less in scope than an audit, whose objective is the expression of an opinion regarding the financial statements. An interim review does not provide such assurance.

The accounting policies adopted in the preparation of the Nexen Historical Track Record Accounts differ in certain material respects from the accounting policies presently adopted by the Company which comply with both IFRS and HKFRS. Differences, other than presentational differences, which would have a significant effect on the Nexen Historical Track Record Accounts had they been prepared in accordance with the accounting policies presently adopted by the Company rather than in accordance with Canadian GAAP for the Nexen 2009 Accounts or IFRS for the Nexen Post 2009 Accounts, are set out below in the section entitled "Nexen's Unaudited Adjusted Financial Information under the Company's Policies".

In particular, disclosure is set out providing:

(a)a comparison between Nexen's consolidated statement of income as extracted from the Nexen Historical Track Record Accounts on the one hand (prepared in accordance with Canadian GAAP or IFRS), and a restatement of such consolidated statement of income had they instead been prepared in accordance with the accounting policies presently adopted by the Company which are in compliance with IFRS and HKFRS. The process applied in the preparation of such restatement is set out below;

(b)a comparison between Nexen's consolidated balance sheets as extracted from the Nexen Historical Track Record Accounts on the one hand (prepared in accordance with Canadian GAAP or IFRS), and a restatement of such balance sheets had they instead been prepared in accordance with the accounting policies presently adopted by the Company which are in compliance with IFRS and HKFRS. The process applied in the preparation of such restatement is also set out below; and

(c)a discussion of the material financial statements line item differences arising out of the restatement exercise outlined in (a) and (b) above.

(the reconciliation for the Nexen 2009 Accounts is referred to as the "2009 Reconciliation Information" and the reconciliation for the Nexen Post 2009 Accounts is referred to as the "Post 2009 Reconciliation Information" and together being referred to as the "Reconciliation Information").

Basis of Preparation

The Reconciliation Information as at and for the year ended 31 December 2009 restating the "Unadjusted Financial Information under Canadian GAAP" of Nexen as if it had been prepared in accordance with the accounting policies presently adopted by the Company which are in compliance with IFRS and HKFRS has been prepared on the assumption that the first time adoption exemptions and elections of IFRS 1 applied by Nexen at 1 January 2010, as set out in Note 26 of Nexen's 2011 annual consolidated financial statements (other than those disclosed in the "Nexen's Unaudited Adjusted Financial Information under the Company's Policies"), did not result in any adjustment to Nexen's consolidated balance sheet as at 1 January 2009 prepared under Canadian GAAP as the preparation of such adjustments would be unduly burdensome for the Company and Nexen. Accordingly, the adjustments included in the Reconciliation Information as at and for the year ended 31 December 2009 do not include any adjustments that would result from the application of the first time adoption exemptions and elections of IFRS 1 applied by Nexen at 1 January 2010, as set out in Note 26 of Nexen's 2011 annual consolidated financial statements.

The Reconciliation Information for the year ended 31 December 2009 is therefore prepared using a different basis than that used in the preparation of Nexen's opening balance sheet as of 1 January 2010, Nexen's date of transition to IFRS, which takes into account all the necessary adjustments resulting from the exemptions and elections on the first time adoption of IFRS.

As a result of the different basis of preparation, the adjusted results as at and for the year ended 31 December 2009 may not be comparable with the adjusted results for each of the two years ended 31 December 2011 and the six months ended 30 June 2012 or any subsequent periods. The adjusted amounts as at 31 December 2009 are different from the amounts reflected on the opening consolidated balance sheet of Nexen as at 1 January 2010 and should not be compared directly with the adjusted amounts as at 31 December 2010 and 2011, 30 June 2012 or any subsequent periods.

The Reconciliation Information as at and for each of the two years ended 31 December 2011 and the six months ended 30 June 2012 is prepared by restating the "Unadjusted Financial Information under IFRS" of Nexen as if it had been prepared in accordance with accounting policies presently adopted by the Company which are in compliance with IFRS and HKFRS, if any.

Reconciliation Process

The Reconciliation Information has been prepared by the Directors by comparing the differences between the accounting policies adopted by Nexen for the year ended 31 December 2009 which are prepared in accordance with Canadian GAAP and for each of the two years ended 31 December 2010 and 2011 and the six months ended 30 June 2012 which are prepared in accordance with IFRS respectively on the one hand, and the accounting policies presently adopted by the Company which are in compliance with IFRS and HKFRS on the other hand and in accordance with the basis of preparation in respect of the year ended 31 December 2009 and each of the two years ended 31 December 2011 and the six months ended 30 June 2012, as appropriate, and quantifying the relevant material financial effects of such differences, if any. Your attention is drawn to the fact that the Reconciliation Information has not been subject to an independent audit. Accordingly, no opinion is expressed by an auditor on whether it presents a true and fair view of Nexen's financial positions as at 31 December 2009, 2010, 2011 and 30 June 2012, nor its results for the years/period then ended under the accounting policies presently adopted by the Company which are in compliance with IFRS and HKFRS.

Deloitte Hong Kong was engaged by the Company to conduct work in accordance with the Hong Kong Standard on Assurance Engagements 3000 "Assurance Engagements Other Than Audits or Reviews of Historical Financial Information" ("HKSAE 3000") issued by the HKICPA on the Reconciliation Information. The work consisted primarily of:

(i)comparing the "Unadjusted Financial Information under Canadian GAAP" or "Unadjusted Financial Information under IFRS" as set out below in the section entitled "Nexen's Unaudited Adjusted Financial Information under the Company's Policies" with the Nexen Historical Track Record Accounts prepared under Canadian GAAP or IFRS, as appropriate;

(ii)considering the adjustments made and evidence supporting the adjustments made in arriving at the "Adjusted Financial Information under the Company's Policies" also set out below in the section entitled "Nexen's Unaudited Adjusted Financial

Information under the Company's Policies", which included examining the differences between Nexen's accounting policies and the Company's accounting policies; and

(iii)checking the arithmetic accuracy of the computation of the "Adjusted Financial Information under the Company's Policies".

Deloitte Hong Kong's engagement did not involve independent examination of any of the underlying financial information. The work carried out in accordance with HKSAE 3000 is different in scope from an audit or a review conducted in accordance with Hong Kong Standards on Auditing or Hong Kong Standards on Review Engagements issued by the HKICPA and consequently, Deloitte Hong Kong did not express an audit opinion nor a review conclusion on the Reconciliation Information. Deloitte Hong Kong's engagement was intended solely for the use of the Directors in connection with this circular and may not be suitable for another purpose. Based on the work performed, Deloitte Hong Kong has concluded that:

(i)the "Unadjusted Financial Information under Canadian GAAP" and "Unadjusted Financial Information under IFRS" as set out in the section entitled "Nexen's Unaudited Adjusted Financial Information under the Company's Policies" is in agreement with the Nexen Historical Track Record Accounts;

(ii)except for the potential impact of those adjustments relating to the application of first time adoption exemptions and elections under IFRS 1 as described in the Basis of Preparation which are not included in the Reconciliation Information, the adjustments reflect, in all material respects, the differences between Nexen's accounting policies and the Company's accounting policies; and

(iii)the computation of the "Adjusted Financial Information under the Company's Policies" is arithmetically accurate.

Nexen's Unaudited Adjusted Financial Information under the Company's Policies

Nexen's consolidated financial statements for the year ended 31 December 2009 have been prepared and presented under Canadian GAAP. Except for the potential impact of those adjustments relating to the application of first time adoption exemptions and elections under IFRS 1 as described in the Basis of Preparation which are not included in the Reconciliation Information, there are no material differences between Nexen's consolidated financial statements for the year ended 31 December 2009 as presented under Nexen's then Canadian GAAP accounting policies, compared to that applying the accounting policies presently adopted by the Company which are in compliance with IFRS and HKFRS other than as set out below:

1) Asset Retirement Obligations

2) Property, Plant and Equipment Componentization

3) Property, Plant and Equipment Major Maintenance

4) Property, Plant and Equipment Impairments

5) Share-based Payments

6) Deferred Income Taxes

Nexen's consolidated financial statements for each of the two years ended 31 December 2010 and 31 December 2011 and for the six months ended 30 June 2011 and 2012 have been prepared and presented under IFRS. There are no material differences between Nexen's consolidated financial statements for each of the two years ended 31 December 2010 and 2011 and for the six months ended 30 June 2011 and 2012 as presented under Nexen's IFRS accounting policies, compared to that applying the accounting policies presently adopted by the Company which are in compliance with IFRS and HKFRS.

The following unaudited adjusted consolidated statements of income for each of the three years ended 31 December 2009, 2010 and 2011 and the six months ended 30 June 2011 and 2012 and the unaudited adjusted consolidated balance sheets as at 31 December 2009, 2010, 2011 and 30 June 2012 of Nexen set out in the Reconciliation Information below are derived from the consolidated financial statements for each of the three years ended 31 December 2009, 2010, 2011 and the unaudited consolidated condensed financial statements for the six months ended 30 June 2012 which are prepared under Canadian GAAP or IFRS, as appropriate, as included in the Appendix II. The consolidated statements of cash flows are not presented as there are no significant differences except for presentational differences. Your attention is drawn to the fact that the work carried out in accordance with HKSAE3000 is different in scope from an audit or a review conducted in accordance with Hong Kong Standards on Auditing or Hong Kong Standards on Review Engagements issued by the HKICPA and consequently, Deloitte Hong Kong did not express an audit opinion nor a review conclusion on the Reconciliation Information.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

Unaudited Adjusted Consolidated Statements of Income under the Company's Policies

| | | For the year ended 31 December | | | | | | | | | For the six months ended 30 June | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2009 | | | 2010 | | | 2011 | | | 2011 | | | 2012 | | |
| C$ millions | Notes | Unadjusted Financial Information under Canadian GAAP Audited | Adjustments Unaudited | Adjusted Financial Information under the Company's Policies Unaudited | Unadjusted Financial Information under IFRS Audited | Adjustments Unaudited | Adjusted Financial Information under the Company's Policies Unaudited | Unadjusted Financial Information under IFRS Audited | Adjustments Unaudited | Adjusted Financial Information under the Company's Policies Unaudited | Unadjusted Financial Information under IFRS Unaudited | Adjustments Unaudited | Adjusted Financial Information under the Company's Policies Unaudited | Unadjusted Financial Information under IFRS Unaudited | Adjustments Unaudited | Adju Finan Infor under the Comp Polic Unau |
| Revenues and Other Income | | | | | | | | | | | | | | | | |
| Net Sales | | 4,203 | – | 4,203 | 5,496 | – | 5,496 | 6,169 | – | 6,169 | 3,105 | – | 3,105 | 3,355 | – | 3,35 |
| Marketing and Other Income | 1 | 859 | 30 | 889 | 323 | – | 323 | 295 | – | 295 | 141 | – | 141 | 158 | – | 158 |
| | | 5,062 | 30 | 5,092 | 5,819 | – | 5,819 | 6,464 | – | 6,464 | 3,246 | – | 3,246 | 3,513 | – | 3,51 |
| Expenses | | | | | | | | | | | | | | | | |
| Operating | 3 | 916 | (12) | 904 | 1,336 | – | 1,336 | 1,431 | – | 1,431 | 704 | – | 704 | 715 | – | 715 |
| Depreciation, Depletion, Amortization and Impairment | 1,2,3, 4,6 | 1,615 | (91) | 1,524 | 1,628 | – | 1,628 | 1,913 | – | 1,913 | 705 | – | 705 | 885 | – | 885 |
| Transportation and Other | | 732 | – | 732 | 566 | – | 566 | 425 | – | 425 | 179 | – | 179 | 225 | – | 225 |
| General and Administrative | 5 | 434 | 35 | 469 | 428 | – | 428 | 300 | – | 300 | 181 | – | 181 | 241 | – | 241 |
| Exploration | | 302 | – | 302 | 328 | – | 328 | 368 | – | 368 | 219 | – | 219 | 215 | – | 215 |
| Finance | | 305 | – | 305 | 362 | – | 362 | 251 | – | 251 | 134 | – | 134 | 145 | – | 145 |
| Loss on Debt Redemption and Repurchase | | – | – | – | – | – | – | 91 | – | 91 | 91 | – | 91 | – | – | – |
| Net (Gain) Loss from Dispositions | | – | – | – | 41 | – | 41 | (38) | – | (38) | – | – | – | (45) | – | (45 |
| | | 4,304 | (68) | 4,236 | 4,689 | – | 4,689 | 4,741 | – | 4,741 | 2,213 | – | 2,213 | 2,381 | – | 2,38 |
| Income from Continuing Operations before Provision for | | 758 | 98 | 856 | 1,130 | – | 1,130 | 1,723 | – | 1,723 | 1,033 | – | 1,033 | 1,132 | – | 1,13 |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Income Taxes | | | | | | | | | | | | | | | | |
| Provision for (Recovery of) Income Taxes | | | | | | | | | | | | | | | | |
| Current | | 773 | – | 773 | 1,125 | – | 1,125 | 1,584 | – | 1,584 | 808 | – | 808 | 876 | – | 876 |
| Deferred | 6 | (527) | 160 | (367) | (449) | – | (449) | (256) | – | (256) | 73 | – | 73 | (24) | – | (24 |
| | | 246 | 160 | 406 | 676 | – | 676 | 1,328 | – | 1,328 | 881 | – | 881 | 852 | – | 852 |
| Net Income from Continuing Operations | | 512 | (62) | 450 | 454 | – | 454 | 395 | – | 395 | 152 | – | 152 | 280 | – | 280 |
| Net Income from Discontinued Operations, Net of Tax | 1,2,6 | 24 | – | 24 | 673 | – | 673 | 302 | – | 302 | 302 | – | 302 | – | – | – |
| Net Income Attributable to Nexen Inc. Shareholders | | 536 | (62) | 474 | 1,127 | – | 1,127 | 697 | – | 697 | 454 | – | 454 | 280 | – | 280 |

Unaudited Adjusted Consolidated Balance Sheets under the Company's Policies

| C$ millions | Notes | As at 31 December 2009 Unadjusted Financial Information under Canadian GAAP Audited | Adjustments Unaudited | Adjusted Financial Information under the Company's Policies Unaudited | 2010 Unadjusted Financial Information under IFRS Audited | Adjustments Unaudited | Adjusted Financial Information under the Company's Policies Unaudited | 2011 Unadjusted Financial Information under IFRS Audited | Adjustments Unaudited | Adjusted Financial Information under the Company's Policies Unaudited | As at June 30 2012 Unadjusted Financial Information under IFRS Unaudited | Adjustments Unaudited | Adjusted Financial Information under the Company's Policies Unaudited |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ASSETS | | | | | | | | | | | | | |
| Current Assets | | | | | | | | | | | | | |
| Cash and Cash Equivalents | | 1,700 | – | 1,700 | 1,005 | – | 1,005 | 845 | – | 845 | 1,255 | – | 1,255 |
| Restricted Cash | | 198 | – | 198 | 40 | – | 40 | 45 | – | 45 | 102 | – | 102 |
| Accounts Receivable | | 2,788 | – | 2,788 | 1,789 | – | 1,789 | 2,247 | – | 2,247 | 1,685 | – | 1,685 |
| Derivative Contracts | | – | – | – | 158 | – | 158 | 119 | – | 119 | 155 | – | 155 |
| Inventories and Supplies | | 680 | – | 680 | 550 | – | 550 | 320 | – | 320 | 283 | – | 283 |
| Other | | 185 | – | 185 | 133 | – | 133 | 115 | – | 115 | 137 | – | 137 |
| Assets Held for Sale | | – | – | – | 729 | – | 729 | – | – | – | – | – | – |
| Total Current Assets | | 5,551 | – | 5,551 | 4,404 | – | 4,404 | 3,691 | – | 3,691 | 3,617 | – | 3,617 |
| Property, Plant and Equipment | 1,2,3, 4,6 | 15,492 | 78 | 15,570 | 14,579 | – | 14,579 | 15,571 | – | 15,571 | 16,030 | – | 16,030 |
| Goodwill | | 339 | – | 339 | 286 | – | 286 | 291 | – | 291 | 292 | – | 292 |
| Deferred Income Tax Assets | | 1,148 | – | 1,148 | 160 | – | 160 | 338 | – | 338 | 442 | – | 442 |
| Derivative Contracts | | – | – | – | 116 | – | 116 | 25 | – | 25 | 5 | – | 5 |
| Other Long-term Assets | | 370 | – | 370 | 102 | – | 102 | 152 | – | 152 | 112 | – | 112 |
| TOTAL ASSETS | | 22,900 | 78 | 22,978 | 19,647 | – | 19,647 | 20,068 | – | 20,068 | 20,498 | – | 20,498 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LIABILITIES | | | | | | | | | | | | | |
| Current Liabilities | | | | | | | | | | | | | |
| Accounts Payable and Accrued Liabilities | 5 | 3,038 | 93 | 3,131 | 2,223 | – | 2,223 | 2,867 | – | 2,867 | 2,285 | – | 2,285 |
| Current Income Taxes Payable | | – | – | – | 345 | – | 345 | 458 | – | 458 | 849 | – | 849 |
| Derivative Contracts | | – | – | – | 168 | – | 168 | 103 | – | 103 | 105 | – | 105 |
| Accrued Interest Payable | | 89 | – | 89 | – | – | – | – | – | – | – | – | – |
| Dividends Payable | | 26 | – | 26 | – | – | – | – | – | – | – | – | – |
| Liabilities Held for Sale | | – | – | – | 582 | – | 582 | – | – | – | – | – | – |
| Total Current Liabilities | | 3,153 | 93 | 3,246 | 3,318 | – | 3,318 | 3,428 | – | 3,428 | 3,239 | – | 3,239 |

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

| | | As at 31 December | | | | | | | | | As at June 30 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2009 | | | 2010 | | | 2011 | | | 2012 | | |
| C$ millions | Notes | Unadjusted Financial Information under Canadian GAAP Audited | Adjustments Unaudited | Adjusted Financial Information under the Company's Policies Unaudited | Unadjusted Financial Information under IFRS Audited | Adjustments Unaudited | Adjusted Financial Information under the Company's Policies Unaudited | Unadjusted Financial Information under IFRS Audited | Adjustments Unaudited | Adjusted Financial Information under the Company's Policies Unaudited | Unadjusted Financial Information under IFRS Unaudited | Adjustments Unaudited | Adjusted Financial Information under the Company's Policies Unaudited |
| Long-Term Debt | | 7,251 | – | 7,251 | 5,090 | – | 5,090 | 4,383 | – | 4,383 | 4,391 | – | 4,391 |
| Deferred Income Tax Liabilities | 6 | 2,811 | 222 | 3,033 | 1,487 | – | 1,487 | 1,488 | – | 1,488 | 1,561 | – | 1,561 |
| Asset Retirement Obligations | 1 | 1,018 | 381 | 1,399 | 1,516 | – | 1,516 | 2,010 | – | 2,010 | 2,020 | – | 2,020 |
| Derivative Contracts | | – | – | – | 115 | – | 115 | 24 | – | 24 | 5 | – | 5 |
| Other Long-term Liabilities | 6 | 1,021 | (502) | 519 | 307 | – | 307 | 362 | – | 362 | 443 | – | 443 |
| | | | | | | | | | | | | | |
| EQUITY | | | | | | | | | | | | | |
| Nexen Inc. Shareholders' Equity | | | | | | | | | | | | | |
| Common Shares | | 1,049 | – | 1,049 | 1,111 | – | 1,111 | 1,157 | – | 1,157 | 1,183 | – | 1,183 |
| Preferred Shares | | – | – | – | – | – | – | – | – | – | 195 | – | 195 |
| Contributed Surplus | | 1 | – | 1 | – | – | – | – | – | – | – | – | – |
| Retained Earnings | | 6,722 | (18) | 6,704 | 6,692 | – | 6,692 | 7,211 | – | 7,211 | 7,435 | – | 7,435 |
| Cumulative Translation Adjustment | 1,2,6 | (190) | (88) | (278) | (37) | – | (37) | 5 | – | 5 | 26 | – | 26 |
| Total Nexen Inc. Shareholders' Equity | | 7,582 | (106) | 7,476 | 7,766 | – | 7,766 | 8,373 | – | 8,373 | 8,839 | – | 8,839 |
| Canexus Non-Controlling Interests | 1,2,6 | 64 | (10) | 54 | 48 | – | 48 | – | – | – | – | – | – |
| Total Equity | | 7,646 | (116) | 7,530 | 7,814 | – | 7,814 | 8,373 | – | 8,373 | 8,839 | – | 8,839 |
| TOTAL LIABILITIES AND EQUITY | | 22,900 | 78 | 22,978 | 19,647 | – | 19,647 | 20,068 | – | 20,068 | 20,498 | – | 20,498 |

Note 1: Asset Retirement Obligations

Consistent with IFRS and HKFRS, asset retirement obligations have been measured under Canadian GAAP based on the estimated cost of future abandonment and discounted to its net present value upon initial recognition. However, adjustments to the discount rate were not reflected in the provision or the related asset under Canadian GAAP unless there was an upward revision of the future cost estimates.

Nexen has re-measured asset retirement obligations in accordance with IAS/HKAS 37 Provisions, Contingent Liabilities and Contingent Assets ("IAS/HKAS 37"). The corresponding amount to be included in the related asset has been estimated by discounting the liability to the date on which the liability first arose, and recalculating accumulated depreciation, depletion and amortization under IFRS and HKFRS.

Had Nexen adopted the Company's accounting policy, the impact of this reclassification on profit or loss for the year ended 31 December 2009 and on the carrying amounts of assets, liabilities and equity as at 31 December 2009 would have been as follows:

| C$ millions | As at and for the Year ended 31 December 2009 Unaudited |
|---|---|
| Asset Retirement Obligation | |
| Pre-tax impact on profit or loss (gain)* | 101 |
| Retained earnings as at 1 January 2009 (decrease) | 320 |
| Cumulative translation adjustment (increase) | 14 |
| Asset retirement obligations (increase) | 381 |
| Property, plant and equipment (increase) | 173 |
| Canexus non-controlling interest (decrease) | 3 |

* Includes the impact of Cdn$11 million gain related to discontinued operations.

Nexen adopted IFRS beginning 1 January 2010 and from this date, Nexen's accounting policy for asset retirement obligations is aligned with that of the Company.

Note 2: Property, Plant and Equipment Componentization

Under Canadian GAAP, Nexen depleted oil and gas capitalized costs using the unit-of-production method on a field-by-field basis and depreciated non-resource capitalized costs based on their estimated useful life. In comparison, the Company's accounting policy is to componentize property, plant and equipment by applying a useful life to each different component of an asset, and depreciate the components accordingly.

Nexen reviewed property, plant and equipment to identify each material component that has a significantly different useful life. As a result, adjustments to the accumulated depletion of certain assets resulted in additional depreciation, depletion and amortization expense.

Had Nexen adopted the Company's accounting policy, the impact of the adjustments on profit or loss for the year ended 31 December 2009 and on the carrying amount of assets, liabilities and equity as at 31 December 2009 would have been as follows:

| C$ millions | As at and for the Year ended 31 December 2009 Unaudited |
|---|---|
| Componentization | |
| Pre-tax impact on profit or loss (gain)* | 36 |
| Retained earnings as at 1 January 2009 (decrease) | 71 |
| Cumulative translation adjustment (decrease) | 2 |
| Property, plant and equipment (decrease) | 49 |
| Canexus non-controlling interest (decrease) | 12 |

* Includes the impact of Cdn$13 million loss related to discontinued operations.

Nexen adopted IFRS beginning 1 January 2010 and from this date, Nexen's accounting policies for property, plant and equipment is aligned with that of the Company.

Note 3: Property, Plant and Equipment Major Maintenance

Under Nexen's Canadian GAAP accounting policies, Nexen expensed operating expenses as incurred, including major maintenance costs. In comparison, the Company's accounting policy is to capitalize major maintenance and turnaround costs and depreciate these costs separately until the next planned major maintenance project.

Had Nexen adopted the Company's accounting policy, the impact of the adjustments on profit or loss for the year ended 31 December 2009 and on the carrying amount of assets, liabilities and equity as at 31 December 2009 would have been as follows:

| C$ millions | As at and for the Year ended 31 December 2009 Unaudited |
|---|---|
| Major Maintenance | |
| Pre-tax impact on profit or loss (gain) | 9 |
| Retained earnings as at 1 January 2009 (increase) | 10 |
| Property, plant and equipment (increase) | 19 |

Nexen adopted IFRS beginning 1 January 2010 and from this date, Nexen's accounting policies for property, plant and equipment is aligned with that of the Company.

Note 4: Property, Plant and Equipment Impairment

Under Nexen's Canadian GAAP accounting policies, if indications of impairment exist and the asset's estimated undiscounted future cash flows were lower than its carrying amount, the carrying value was written down to fair value. In accordance with IAS/HKAS 36 Impairment of assets ("IAS/HKAS 36"), if indications of impairment exist, the asset's carrying value is immediately compared to its estimated recoverable amount, which could trigger additional impairment under IFRS and HKFRS. An asset's recoverable amount is the higher of an asset's or cash generating unit's fair value less cost to sell or value-in-use.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

Nexen assessed its properties to determine if indications of impairment existed at 1 January 2009 and 31 December 2009. For those properties where indications of impairment existed, the properties' carrying values were compared to recoverable amount in accordance with IAS/HKAS 36, and as a result recorded additional impairment expense in 2009.

Had Nexen adopted the Company's accounting policy, the impact of the adjustments on profit or loss for the year ended 31 December 2009 and on the carrying amount of assets, liabilities and equity as at 31 December 2009 would have been as follows:

| C$ millions | As at and for the Year ended 31 December 2009 Unaudited |
|---|---|
| Impairment | |
| Pre-tax impact on profit or loss (loss) | 17 |
| Retained earnings as at 1 January 2009 (decrease) | 38 |
| Property, plant and equipment (decrease) | 55 |

Nexen adopted IFRS beginning 1 January 2010 and from this date, Nexen's accounting policies for property, plant and equipment is aligned with that of the Company.

Note 5: Share-based Payments

Under Nexen's Canadian GAAP accounting policies, obligations for liability-based stock compensation plans were recorded using the intrinsic-value method of accounting. IFRS/HKFRS 2 Share-based Payments ("IFRS/HKFRS 2") requires share-based payment obligations be recorded at fair value and subsequently re-measured at each reporting period. Nexen has re-measured the share-based payment obligation at fair value for all unsettled awards for 2009.

Had Nexen adopted the Company's accounting policy, the impact of the adjustments on profit or loss for the year ended 31 December 2009 and on the carrying amount of assets, liabilities and equity as at 31 December 2009 would have been as follows:

| C$ millions | As at and for the Year ended 31 December 2009 Unaudited |
|---|---|
| Share-based Payments | |
| Pre-tax impact on profit or loss (loss) | 35 |
| Retained earnings as at 1 January 2009 (decrease) | 58 |
| Accrued liabilities (increase) | 93 |

Nexen adopted IFRS beginning 1 January 2010 and from this date, Nexen's accounting policy for share-based payments is aligned with that of the Company.

Note 6: Deferred Income Taxes

In 2008, Nexen completed an internal reorganization and financing of assets in the North Sea, which provided a one-time tax deduction in the UK. Canadian GAAP precluded Nexen from recognizing the full estimated benefit of the tax deductions until the assets were recognized in net income either by a sale or depletion through use. As a result, Nexen deferred the initial recognition of the benefit and the benefit was amortized to deferred income tax expense over the life of the underlying assets under Canadian GAAP. Under IAS and HKAS 12 Income Taxes ("IAS/HKAS 12"), such benefit should be recognized in the period in which the deduction is obtained. As a result, Nexen recognized the remaining tax credit in profit or loss during the year ended 31 December 2008.

Under Canadian GAAP, deferred taxes were generally provided on all temporary differences. Conversely, IFRS/HKFRS does not recognize deferred taxes on temporary differences arising from the initial recognition of assets or liabilities in transactions that are not business combinations and that effect neither accounting nor taxable profit or loss.

All adjustments to IFRS/HKFRS net income for the year ended 31 December 2009 as described in notes 1 – 5 were tax effected which increased deferred tax expenses by Cdn$47 million for the period.

Had Nexen adopted the Company's accounting policy, the impact of the adjustments on profit or loss for the year ended 31 December 2009 and the carrying amount of assets, liabilities and equity as at 31 December 2009 would have been as follows:

| C$ millions | As at and for the Year ended 31 December 2009 Unaudited |
|---|---|
| Deferred Income Taxes | |
| Impact on profit or loss (loss)* | 156 |
| Retained earnings as at 1 January 2009 (increase) | 521 |
| Cumulative translation adjustment (decrease) | 100 |
| Property, plant and equipment (decrease) | 10 |
| Deferred income tax liabilities (increase) | 222 |
| Other long-term liabilities (decrease) | 502 |
| Canexus non-controlling interest (increase) | 5 |

* Includes the impact of Cdn$2 million gain related to discontinued operations.

Nexen adopted IFRS beginning 1 January 2010 and from this date, Nexen's accounting policy for income taxes is aligned with that of the Company.

## III. SUPPLEMENTAL FINANCIAL INFORMATION OF NEXEN GROUP

The Company sets out the following supplemental financial information of Nexen Group, which was not included in Nexen's Audited Consolidated Financial Statements showing the financial information for the three financial years ended 31 December 2011, 2010 and 2009, nor was it included in Nexen's Unaudited Condensed Consolidated Financial Statements for the six months ended 30 June 2012.

### 1. Accounting Policies

The accounting policies Nexen follows are described in Note 2 of the Audited Consolidated Financial Statements for the years ended 31 December 2011, 2010 and 2009 included within this circular. There have been no changes to Nexen's accounting policies since 31 December 2011. The information set out in this supplemental financial information has been prepared in accordance with Nexen's accounting policies as set out in the 2011 Audited Consolidated Financial Statements.

Detailed Disclosure for Investments in Joint Arrangements

In review of Nexen's existing accounting policies in relation to Joint Arrangements and to the Company's accounting policies as set out in the 2011 Audited Consolidated Financial Statements, no transactions have been identified that would be materially affected by the Company's early adoption of IFRS10, IFRS11, IFRS12, IAS27 (revised) and IAS28 (revised).

2. Critical Accounting Estimates

Critical accounting estimates that apply to the years ended 31 December 2011, 2010 and 2009 are set out in the 2011, 2010 and 2009 Audited Consolidated Financial Statements included within this circular. The critical accounting estimates that apply to the six months ended 30 June 2012 are consistent with those set out within Note 2 of Nexen's 2011 Audited Consolidated Financial Statements.

3. Loans and Borrowings

(a) Long-Term Debt Maturities

The maturities on the loans and borrowings of Nexen are as follows:

| (Cdn$ millions) | As at 30 June 2012 | As at 31 December 2011 | As at 31 December 2010 | As at 31 December 2009 |
|---|---|---|---|---|
| Repayable: | | | | |
| Within one year | – | – | – | – |
| After one year but within two years | – | – | – | 233 |
| After two years but within five years | 191 | 128 | 746 | 2,195 |
| After five years | 4,281 | 4,335 | 4,425 | 4,919 |
| | 4,472 | 4,463 | 5,171 | 7,347 |
| Unamortized Debt Issue Costs | (81) | (80) | (81) | (88) |
| Total | 4,391 | 4,383 | 5,090 [1] | 7,259 |

1 Nexen sold its 65% ownership interest in Canexus Income Fund in February 2011 and long-term debt of $414 million was included in liabilities held for sale as at 31 December 2010.

(b) Finance Expense

| (Cdn$ millions) | Six months ended 30 June 2012 | Six months ended 30 June 2011 | Year ended 31 December 2011 | Year ended 31 December 2010 | Year ended 31 December 2009 |
|---|---|---|---|---|---|
| Interest Expense on Long-Term Debt: | | | | | |
| Wholly repayable within one year | – | – | – | – | – |
| After one year but within two years | – | – | 6 [1] | – | 8 |
| After two years but within five years | 5 | 9 | 8 | 54 | 44 |
| After five years | 143 | 149 | 290 | 307 | 308 |
| | 148 | 158 | 304 | 361 | 360 |
| Other Interest Expense and Fees: | | | | | |
| Accretion Expense Related to Asset Retirement Obligation | 26 | 23 | 44 | 47 | 70 |
| Other Interest and Fees | 12 | 10 | 27 | 34 | 17 |
| Less: Capitalized | (41) | (57) | (124) | (80) | (72) |
| | | | | | |
| Total | 145 | 134 [2] | 251 [2] | 362 [2] | 375 |

1 In April 2011 Nexen redeemed US$500 million of notes due in November 2013. Interest expense relates to amounts incurred prior to the redemption.

2 Nexen sold its 65% ownership interest in Canexus Income Fund in February 2011 and interest expense on long-term debt of $2 million for the six months and year ended 31 December 2011 was included in discontinued operations ($19 million for the year ended 31 December 2010).

Capitalized interest relates to and is included as part of the cost of Nexen’s oil and gas properties. The capitalization rates are based on Nexen’s weighted-average cost of borrowings.

4. Aging Analysis of Trade Receivables

Receivable terms are typically up to 30 days. Substantially all trade receivables were current as of 30 June 2012, 31 December 2011, 2010 and 2009.

Credit Policy

Nexen seeks to establish open credit with counterparties that it trades with. Where creditworthiness is not established or revoked (new or existing counterparts), Nexen would require credit enhancement such as parental guarantees, letters of credit, cash prepayment, credit insurance, etc. to mitigate credit exposure. Generally, standard settlement in the oil

and gas industry is on the 20th or 25th of the month following delivery and generally 30 days after delivery for cargo business. Cargo payment terms can differ between counterparties, as can oil sales via pipeline deals depending on the counterparty situation.

5. Aging Analysis of Trade Payables

All the trade payables amounts are for goods and services provided to Nexen prior to the end of the financial period which are unpaid. As at 30 June 2012, 31 December 2011, 2010 and 2009 substantially all the trade payables were aged within 50 days. The trade payables are non-interest bearing and are normally settled within 50 days.

6. Concentration of Customers and Suppliers

(a) Concentration of Suppliers, Gross Purchases

Nexen's five largest suppliers represent less than 30% of total purchases combined.

(b) Concentration of Customers, Gross Sales

| (% of total sales) | Six months ended 30 June 2012 | | Six months ended 30 June 2011 | | Year ended 31 December 2011 | | Year ended 31 December 2010 | | Year ended 31 December 2009 | |
|---|---|---|---|---|---|---|---|---|---|---|
| Largest customer | 12 | % | 12 | % | 11 | % | 13 | % | 8 | % |
| Five largest customers, combined | 43 | % | 46 | % | 43 | % | 47 | % | 32 | % |

None of Nexen's directors had any interest in the five largest customers during the periods ended 30 June 2012 and 2011, and the years ended 31 December 2011, 2010 and 2009.

7. Investments in Subsidiaries

The following table includes the subsidiaries of Nexen Inc. which materially contribute to the results of operations or hold a material portion of the total assets or liabilities of Nexen:

| | | | | Equity holdings | | | |
|---|---|---|---|---|---|---|---|
| Name of Subsidiary | Country and Date of Incorporation | Principal Activity | Particulars of issued or paid up capital | As at 30 June 2012 | As at 31 December 2011 | As at 31 December 2010 | As at 31 December 2009 |
| Nexen Petroleum UK Limited | England & Wales 4 April 1974 | Production and sale of crude oil in UK | GBP £98,009,131 | 100% | 100% | 100% | 100% |
| Nexen Petroleum Nigeria Limited | Nigeria 3 March 1998 | Production and sale of crude oil in Nigeria | NGN $30,000,000 | 100% | 100% | 100% | 100% |
| Nexen Petroleum Offshore USA Inc. | Delaware, U.S.A. 20 July 1990 | Production and sale of crude oil in USA | US$12,790 | 100% | 100% | 100% | 100% |
| Nexen Marketing | Alberta, Canada 1 January 1995 | Purchase and sale of crude oil, natural gas and electricity in North America | N/A | 100% | 100% | 100% | 100% |
| Nexen Oil Sands Partnership | Alberta, Canada 22 March 2005 | Production and sale of crude oil in Canada | N/A | 100% | 100% | 100% | 100% |
| Canadian Nexen Petroleum Yemen1 | Alberta, Canada 31 March 1994 | Production and sale of crude oil in Yemen | N/A | 100% | 100% | 100% | 100% |

1 Canadian Nexen Petroleum Yemen was not considered a principal subsidiary of Nexen Inc. at 30 June 2012.

8. Director's Remuneration

Nexen provides all non-executive directors with a competitive compensation package that includes annual retainers and meeting fees, benefits and equity-based awards in the form of deferred share units (DSUs). Nexen's Board of Directors review director compensation at least once every two years to ensure it is appropriate and competitive. Nexen's chief executive officer (CEO) maintains a position on the Board of Directors but does not receive director compensation for this role. Nexen did not at any time during the period 1 January 2009 to 30 June 2012 waive any directors' remuneration.

Non-executive directors of Nexen earn the following fees:

Annual retainers and meeting fees

| (C$) | 2012 | 2011 | 2010 | 2009 |
|---|---|---|---|---|
| Board Chair Retainer | 250,000 | 250,000 | 250,000 | 250,000 |
| Board Member Retainer | 60,000 | 35,000 | 35,000 | 35,000 |
| Audit Committee Chair Retainer | 17,000 | 19,700 | 19,700 | 19,700 |
| Other Committee Chair Retainer | 2,500 | 5,300 | 5,300 | 5,300 |
| Committee Member Retainer | 5,000 | 9,100 | 9,100 | 9,100 |
| Board and Committee Meeting Fee (per meeting) | 1,800 | 1,800 | 1,800 | 1,800 |

Allowances

A travel allowance of C$1,500 is paid when a non-executive director travels outside his or her home province or state, or travels more than three hours round trip, to attend a Nexen meeting or site visit. Nexen also reimburses directors for out-of-pocket travel expenses.

Benefits

Non-executive directors can receive benefits coverage at Nexen’s expense, including basic life insurance, extended health care, dental, business travel, accident insurance and reimbursement of provincial health care premiums (in certain jurisdictions). Mr. Zaleschuk, a former CEO of Nexen, is a retiree in Nexen’s pension plan. His pension benefit is for previous employee service.

Equity-based compensation

Non-executive directors are granted DSU awards at the discretion of the Board of Directors. A DSU is a unit equal to the value of a Nexen common share. Dividend equivalents are earned at the same rate as cash dividends paid on Nexen’s common shares. DSUs do not have voting rights because there are no actual shares underlying the units. DSUs vest at the time of grant, and are paid out only when the director leaves the Board. Nexen has the option to make payments in cash or common shares purchased on the open market.

The remuneration of Nexen's directors for the six months ended 30 June 2012 is set out below:

(C$)

| Name of Nexen Director | Total Fees Earned1 | DSU Awards1 | All Other Compensation2 | Total Compensation |
|---|---|---|---|---|
| William Berry | 65,150 | – | 2,175 | 67,325 |
| Robert Bertram | 58,500 | – | 3,522 | 62,022 |
| Thomas Ebbern | 58,800 | – | 758 | 59,558 |
| Dennis Flanagan3 | 49,387 | – | 5,346 | 54,733 |
| Barry Jackson | 94,927 | – | 8,418 | 103,345 |
| Kevin Jenkins | 59,050 | – | 7,297 | 66,347 |
| Anne McLellan | 50,900 | – | 5,304 | 56,204 |
| Eric Newell | 53,950 | – | 9,293 | 63,243 |
| Thomas O'Neill | 66,300 | – | 7,104 | 73,404 |
| Kevin Reinhart4 | – | – | – | – |
| Francis Saville | 92,816 | – | 8,152 | 100,968 |
| Arthur Scace | 63,900 | – | 882 | 64,782 |
| John Willson | 54,200 | – | 7,613 | 61,813 |
| Victor Zaleschuk | 60,050 | – | 5,544 | 65,594 |
| | 827,930 | – | 71,408 | 899,338 |

1Includes all retainers, travel allowance and meeting fees, including those paid in DSUs. DSUs are typically issued in the second half of the year.

2The total value of perquisites provided to each non-executive director is less than either C$50,000 or 10% of total fees, and is not included in this column. Amounts reflect life insurance premiums paid by Nexen, reinvested dividends earned in 2012 valued at the closing market price of Nexen common shares on the TSX on the payment dates.

3Mr. Flanagan retired from the board on 25 April 2012.

4Mr. Reinhart maintains a position on the Board of Directors but does not receive director compensation for this role.

The remuneration of Nexen's directors for the six months ended 30 June 2011 is set out below:

(C$)

| Name of Nexen Director | Total Fees Earned1 | DSU Awards1 | All Other Compensation2 | | Total Compensation |
|---|---|---|---|---|---|
| William Berry | 71,950 | – | 1,586 | | 73,536 |
| Robert Bertram | 59,350 | – | 2,289 | | 61,639 |
| Thomas Ebbern | 1,058 | – | – | | 1,058 |
| Dennis Flanagan | 66,300 | – | 16,694 | 3 | 82,994 |
| Barry Jackson | 72,250 | – | 6,983 | | 79,233 |
| Kevin Jenkins | 75,550 | – | 6,020 | | 81,570 |
| Anne McLellan | 67,800 | – | 4,421 | | 72,221 |
| Eric Newell | 70,450 | – | 7,971 | | 78,421 |
| Thomas O'Neill | 82,750 | – | 5,701 | | 88,451 |
| Marvin Romanow4 | – | – | – | | – |
| Francis Saville | 125,000 | – | 6,625 | | 131,625 |
| Arthur Scace | 1,057 | – | – | | 1,057 |
| John Willson | 64,450 | – | 6,711 | | 71,161 |
| Victor Zaleschuk | 62,000 | – | 4,837 | | 66,837 |
| | 819,965 | – | 69,838 | | 889,803 |

1 Includes all retainers, travel allowance and meeting fees, including those paid in DSUs. DSUs are typically issued in the second half of the year.

2 The total value of perquisites provided to each non-executive director is less than either C$50,000 or 10% of total fees, and is not included in this column. Amounts reflect life insurance premiums paid by Nexen, reinvested dividends earned in 2011 valued at the closing market price of Nexen common shares on the TSX on the payment dates.

3 Mr. Flanagan is the board chair of Canexus Income Fund and received fees of C$12,056 from Canexus Income Fund as at 7 February 2011.

4 Mr. Romanow maintained a position on the Board of Directors but does not receive director compensation for this role.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

The remuneration of Nexen's directors for the year ended 31 December 2011 is set out below:

(C$)

| Name of Nexen Director | Total Fees Earned1 | DSU Awards2 | All Other Compensation3 | | Total Compensation |
|---|---|---|---|---|---|
| William Berry | 143,600 | 110,022 | 3,095 | | 256,717 |
| Robert Bertram | 131,600 | 110,022 | 4,865 | | 246,487 |
| Thomas Ebbern | 50,708 | 110,022 | 15 | | 160,745 |
| Dennis Flanagan | 132,000 | 110,022 | 21,353 | 4 | 263,375 |
| Barry Jackson | 162,600 | 110,022 | 14,347 | | 286,969 |
| Kevin Jenkins | 145,400 | 110,022 | 12,327 | | 267,749 |
| Anne McLellan | 130,200 | 110,022 | 8,937 | | 249,159 |
| Eric Newell | 135,500 | 110,022 | 16,268 | | 261,790 |
| Thomas O'Neill | 174,800 | 110,022 | 11,740 | | 296,562 |
| Marvin Romanow5 | – | – | – | | – |
| Francis Saville | 253,000 | 243,382 | 13,276 | | 509,658 |
| Arthur Scace | 55,208 | 110,022 | 56 | | 165,286 |
| John Willson | 123,500 | 110,022 | 13,523 | | 247,045 |
| Victor Zaleschuk | 133,900 | 110,022 | 9,691 | | 253,613 |
| | 1,772,016 | 1,563,646 | 129,493 | | 3,465,155 |

1Includes all retainers, travel allowance and meeting fees, including those paid in DSUs.

2The grant date fair value of DSUs granted on 28 October 2011, based on the closing market price of Nexen common shares on the TSX on 27 October 2011, of C$16.67 per share.

3The total value of perquisites provided to each non-executive director is less than either $50,000 or 10% of total fees, and is not included in this column. Amounts reflect life insurance premiums paid by Nexen, reinvested dividends earned in 2011 valued at the closing market price of Nexen common shares on the TSX on the payment dates and Canexus Income Fund fees.

4Mr. Flanagan is the Board Chair of Canexus Income Fund and received C$12,056 from Canexus Income Fund as at 7 February 2011.

5Mr. Romanow maintained a position on the Board of Directors but did not receive director compensation for this role.

The remuneration of Nexen's directors for the year ended 31 December 2010 is set out below:

(C$)

| Name of Nexen Director | Total Fees Earned1 | DSU Awards2 | All Other Compensation3 | | Total Compensation |
|---|---|---|---|---|---|
| William Berry | 122,600 | 110,650 | 1,977 | | 235,227 |
| Robert Bertram | 111,200 | 110,650 | 2,853 | | 224,703 |
| Dennis Flanagan | 114,567 | 110,650 | 185,058 | 4 | 410,275 |
| Barry Jackson | 129,800 | 110,650 | 12,022 | | 252,472 |
| Kevin Jenkins | 133,100 | 110,650 | 10,912 | | 254,662 |
| Anne McLellan | 124,500 | 110,650 | 7,317 | | 242,467 |
| Eric Newell | 128,000 | 110,650 | 13,997 | | 252,647 |
| Thomas O'Neill | 145,400 | 110,650 | 10,271 | | 266,321 |
| Marvin Romanow5 | – | – | – | | – |
| Francis Saville | 253,000 | 243,430 | 10,974 | | 507,404 |
| John Willson | 117,800 | 110,650 | 11,946 | | 240,396 |
| Victor Zaleschuk | 109,900 | 110,650 | 8,614 | | 229,164 |
| | 1,489,867 | 1,349,930 | 275,941 | | 3,115,738 |

1Includes all retainers, travel allowance and meeting fees, including those paid in DSUs.

2The grant date fair value of DSUs granted on 6 December 2010, based on the closing market price of Nexen common shares on the TSX on 3 December 2010, of C$22.13 per share.

3The total value of perquisites provided to each non-executive director is less than either C$50,000 or 10% of total fees, and is not included in this column. Amounts reflect life insurance premiums paid by Nexen, reinvested dividends earned in 2010 valued at the closing market price of Nexen common shares on the TSX on the payment dates and Canexus Income Fund fees.

4Mr. Flanagan is the Board Chair of Canexus Income Fund and was paid fees of C$107,500, received deferred trust units of Canexus Income Fund valued at C$47,040 and distributions on his trust units of C$22,299 in 2010. The total is included in this column.

5Mr. Romanow maintained a position on the Board of Directors but did not receive director compensation for this role.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

The remuneration of Nexen's directors for the year ended 31 December 2009 is set out below:

(C$)

| Name of Nexen Director | Total Fees Earned1 | DSU Awards2 | All Other Compensation3 | | Total Compensation |
|---|---|---|---|---|---|
| William Berry | 85,900 | 124,750 | 882 | | 211,532 |
| Robert Bertram | 85,900 | 124,750 | 859 | | 211,509 |
| Dennis Flanagan | 102,800 | 124,750 | 145,409 | 4 | 372,959 |
| David Hentschel5 | 38,167 | – | 2,874 | | 41,041 |
| Barry Jackson | 119,300 | 124,750 | 9,906 | | 253,956 |
| Kevin Jenkins | 127,700 | 124,750 | 9,827 | | 262,277 |
| Anne McLellan | 119,400 | 124,750 | 5,559 | | 249,709 |
| Eric Newell | 122,933 | 124,750 | 11,845 | | 259,528 |
| Thomas O'Neill | 143,600 | 124,750 | 9,191 | | 277,541 |
| Marvin Romanow6 | – | – | – | | – |
| Francis Saville | 256,000 | 199,600 | 9,291 | | 464,891 |
| Richard Thomson5 | 46,567 | – | 7,266 | | 53,833 |
| John Willson | 129,200 | 124,750 | 9,946 | | 263,896 |
| Victor Zaleschuk | 104,800 | 124,750 | 7,547 | | 237,097 |
| | 1,482,267 | 1,447,100 | 230,402 | | 3,159,769 |

1Includes all retainers, travel allowance and meeting fees, including those paid in DSUs.

2The grant date fair value of DSUs granted on 7 December 2009, based on the closing market price of Nexen common shares on the TSX on 4 December 2009, of C$24.95 per share.

3The total value of perquisites provided to each non-executive director is less than either C$50,000 or 10% of total fees, and is not included in this column. Amounts reflect life insurance premiums paid by Nexen, reinvested dividends earned in 2009 valued at the closing market price of Nexen common shares on the TSX on the payment dates and Canexus Income Fund fees.

4Mr. Flanagan is the Board Chair of Canexus Income Fund and was paid fees of C$84,000, received deferred trust units of Canexus Income Fund valued at C$36,330 and distributions on his trust units of C$17,923 in 2009. The total is included in this column.

5Mr. Hentschel and Mr. Thomson retired from the board on 28 April 2009.

6Mr. Romanow maintained a position on the Board of Directors but did not receive director compensation for this role.

9. Five highest paid individuals

Total Compensation payable to the five highest paid employees at Nexen is as follows:

| (C$) | Six months ended 30 June 2012 | Six months ended 30 June 2011 | Year ended 31 December 2011 | Year ended 31 December 2010 | Year ended 31 December 2009 |
|---|---|---|---|---|---|
| Salaries and Other Benefits | 3,752,633 | 2,237,381 | 4,093,459 | 3,763,884 | 3,441,467 |
| Long-term Incentives1 | 6,580,552 | – | 3,565,142 | 12,962,248 | 11,380,023 |
| Annual Cash Incentives | – | – | 593,000 | 2,974,000 | 972,368 |
| Pension Value2 | 1,900,959 | 1,994,528 | 2,604,000 | 3,856,400 | 5,129,836 |
| | 12,234,144 | 4,231,909 | 10,855,601 | 23,556,532 | 20,923,694 |

1Long-term incentives include stock-based compensation in the form of Tandem Options (TOPs), Stock Appreciation Rights (STARs) and Restricted Share Units (RSUs). The amounts presented represent estimated fair value on grant date.

2Pension value represents the current service cost, minus the amount members are required to contribute to the plan, plus any change in obligations for compensation increases that exceed managerial assumptions.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

The compensation fell within the following bands:

| (Number of individuals, unless otherwise noted) | Six months ended 30 June 2012 | Six months ended 30 June 2011 | Year ended 31 December 2011 | Year ended 31 December 2010 | Year ended 31 December 2009 |
|---|---|---|---|---|---|
| HK$83.7 – 84.5 million | | | | | |
| (C$11.0 – 11.1 million) | | | | | 1 |
| HK$81.4 – 82.2 million | | | | | |
| (C$10.7 – 10.8 million) | | | | 1 | |
| HK$39.6 – 40.4 million | | | | | |
| (C$5.2 – 5.3 million) | | | | 1 | |
| HK$38.1 – 38.8 million | | | | | |
| (C$5.0 – 5.1 million) | | | 1 | | |
| HK$25.9 – 26.7 million | | | | | |
| (C$3.4 – 3.5 million) | | | | | 1 |
| HK$23.6 – 24.4 million | | | | | |
| (C$3.1 – 3.2 million) | 1 | | | | |
| HK$22.1 – 22.9 million | | | | | |
| (C$2.9 – 3.0 million) | | | | 1 | |
| HK$19.0 – 19.8 million | | | | | |
| (C$2.5 – 2.6 million) | | | | 1 | 1 |
| HK$17.5 – 18.3 million | | | | | |
| (C$2.3 – 2.4 million) | 2 | 1 | | | |
| HK$16.7 – 17.5 million | | | | | |
| (C$2.2 – $2.3 million) | 1 | | | | 1 |
| HK$15.2 – 16.0 million | | | | | |
| (C$2.0 – 2.1 million) | 1 | | | | |
| HK$14.5 – 15.3 million | | | | | |
| (C$1.9 – 2.0 million) | | | 1 | 1 | |
| HK$12.9 – 13.7 million | | | | | |
| (C$1.7 – 1.8 million) | | | | | 1 |
| HK$9.9 – 10.7 million | | | | | |
| (C$1.3 – 1.4 million) | | | 1 | | |
| HK$9.1 – 9.9 million | | | | | |
| (C$1.2 – 1.3 million) | | | 2 | | |
| HK$5.3 – 6.1 million | | | | | |
| (C$0.7 – 0.8 million) | | 1 | | | |
| HK$3.0 – 3.8 million | | | | | |
| (C$0.4 – 0.5 million) | | 1 | | | |
| HK$2.3 – 3.0 million | | | | | |
| (C$0.3 – 0.4 million) | | 2 | | | |
| | 5 | 5 | 5 | 5 | 5 |

For the purpose of the table above, Canadian dollar amounts have been translated to Hong Kong dollars at the rate of exchange prevailing at close of business on 30 June 2012 (HK$/C$ = 7.61).

The five individuals whose compensation was the highest at Nexen are analyzed as follows:

| (Number of individuals) | Six months ended 30 June 2012 | Six months ended 30 June 2011 | Year ended 31 December 2011 | Year ended 31 December 2010 | Year ended 31 December 2009 |
|---|---|---|---|---|---|
| Nexen directors | 1 | 1 | 1 | 1 | 1 |
| Other individuals | 4 | 4 | 4 | 4 | 4 |
| | 5 | 5 | 5 | 5 | 5 |

## 10. Share-Based Payments

Please refer to Note 2 (R), 'Stock-based Compensation' and Note 18, 'Equity', of Nexen's 2011 Audited Consolidated Financial Statements for more information on share-based payments. There were no changes to Nexen's accounting policies for the six months ended 30 June 2012.

Nexen has four approved share option plans within the long-term incentive program. Additional information about the plans are as follows:

### Tandem Options (TOPs)

Participants of the TOPs plan include officers and employees of Nexen or any wholly-owned subsidiary. TOPs to purchase common shares are granted at the discretion of the board of directors. Each TOP gives the holder the right to either purchase one Nexen common share at the exercise price or receive a cash payment equal to the excess of market price over the exercise price. The total number of options issued under this plan and any other share compensation arrangement shall not exceed 14,250,000 shares (on a non-diluted basis) at the date of the grant of the option. The total number of TOPs granted has not exceeded this threshold at any point in the comparative periods. The total number of TOPs issued to any holder cannot exceed 5% of the issued and outstanding shares (on a non-diluted basis). TOPs granted vest over three years and are exercisable on a cumulative basis over five years. In 2010, certain TOPs granted contained a performance vesting condition. The TOPs plan has an unlimited remaining life; however, the Board may amend, suspend or discontinue the plan at any time.

### Stock Appreciation Rights (STARs)

Participants of the STARs plan include officers and employees of Nexen or any wholly-owned subsidiary. Under the STARs plan, officers and employees are entitled to receive a cash payment equal to the excess of the market price of the common shares over the exercise price of the right. STARs cannot be converted to shares and holders are not entitled to any shareholder rights. The total number of STARs granted to any holder under this plan shall not exceed 5% of the issued and outstanding shares (on a non-diluted basis)

at the date of the grant of the STAR. The total number of STARs granted has not exceeded 5% of the outstanding common shares at any point in the comparative periods. The total number of STARs issued to any holder within a one year period cannot exceed 2% of the issued and outstanding shares. STARs granted vest over three years and are exercisable on a cumulative basis over five years. In 2010, certain STARs granted contained a performance vesting condition. The STARs plan has an unlimited remaining life; however, the Board may amend, suspend or discontinue the plan at any time.

Restricted Share Units (RSUs)

Participants of the RSU plan include officers and employees of Nexen or any wholly-owned subsidiary. Under the RSU plan, officers and employees are entitled to receive a cash payment equal to the average closing market price of one common share for the 20 days prior to the vesting date for each RSU granted. RSUs cannot be converted to shares and holders are not entitled to any shareholder rights. There are no individual or total restrictions on the amount of RSUs that can be granted or held. All RSUs vest evenly over three years and are exercised and paid automatically as they vest. Beginning in 2011, certain RSUs granted contain a performance vesting condition. The RSU plan has an unlimited remaining life; however, the Board may amend, suspend or discontinue the plan at any time.

Deferred Share Units (DSUs)

DSUs are equity-based awards granted to directors. The units accumulate over a director's term of service and vest when the director leaves the board. DSUs permit the holder to receive a payment in cash or shares equal to the market value of the stock on the vesting date. There are no individual or total maximum restrictions on the amount of DSUs that can be granted or held. The DSU plan has an unlimited remaining life; however, the Board may amend, suspend or discontinue the plan at any time.

11. Other Long-Term Assets

| (C$ millions, unless otherwise noted) | Exchange Listed | Equity Holdings as at 30 June 2012 | Equity Holdings as at 31 December 2011 | Equity Holdings as at 31 December 2010 | Equity Holdings as at 31 December 2009 |
|---|---|---|---|---|---|
| IGas Energy Plc1 | AIM | 24.48 % | 24.48 % | – | – |
| Carrying value | | 38 | 41 | – | – |

1 IGAS Energy Plc was incorporated in England, UK and the equity holdings represents the proportion of the nominal value of issued Ordinary Shares held.

Nexen did not hold any other significant long-term investments as at the dates noted above.

12. Auditor Remuneration

| (C$) | Six months ended 30 June 2012 | Six months ended 30 June 2011 [1] | Year ended 31 December 2011 [1] | Year ended 31 December 2010 | Year ended 31 December 2009 |
|---|---|---|---|---|---|
| Audit Fees[2] | 1,862,730 | 974,113 | 2,678,492 | 3,252,415 | 3,591,321 |
| Audit-Related Fees[3] | 447,151 | 343,844 | 702,332 | 1,727,203 | 1,786,308 |
| Tax Fees[4] | 59,627 | 52,338 | 69,291 | 59,251 | 151,269 |
| All Other Fees[5] | 267,329 | 243,194 | 555,078 | 163,975 | 262,848 |
| Total | 2,636,837 | 1,613,489 | 4,005,193 | 5,202,844 | 5,791,746 |

[1] Excludes fees related to Canexus Income Fund as Nexen's remaining interest was sold in early 2011.

[2] Audit of annual financial statements or services provided in connection with statutory and regulatory filings or engagements.

[3] Assurance and related services that are reasonably related to the performance of the audit or review of subsidiary financial statements and are not reported as audit fees.

[4] Tax compliance services and tax-related consultation.

[5] Subscriptions to auditor-provided and supported tools.

IV. MANAGEMENT DISCUSSION AND ANALYSIS OF NEXEN

The following is the management discussion and analysis of the results of Nexen for each of the three years ended 31 December 2011 and the six months ended 30 June 2012. Unless otherwise noted, tabular amounts are in millions of Canadian dollars. Oil and gas volumes, reserves and related performance measures are presented on a working interest before royalties basis.

I. REVIEW OF HISTORICAL RESULTS

Six Months Ended 30 June, 2012

The following should be read in conjunction with the Unaudited Condensed Consolidated Financial Statements of Nexen for the three and six months ended June 30, 2012, which have been prepared in accordance with IFRS as set out above in the section entitled "Appendix II – Financial Information of Nexen Group – Published Financial Information of Nexen Group for Each of the Three Years Ended 31 December 2009, 2010 and 2011 and the Six Months Ended 30 June 2012". The date of this discussion is July 18, 2012.

1. Executive Summary

| | Three Months Ended | | | Six Months Ended | | |
|---|---|---|---|---|---|---|
| (C$ millions, except as indicated) | June 30 2012 | March 31 2012 | June 30 2011 | June 30 2012 | June 30 2011 | |
| Production before Royalties1 (mboe/d) | 213 | 202 | 204 | 208 | 218 | |
| Production after Royalties (mboe/d) | 207 | 192 | 180 | 200 | 194 | |
| Cash Flow from Operations2 | 707 | 670 | 598 | 1,377 | 1,267 | 3 |
| Net Income | 109 | 171 | 252 | 280 | 4,54 | 3 |
| Earnings per Common Share, Basic (C$/share) | 0.20 | 0.32 | 0.48 | 0.52 | 0.86 | 3 |
| Earnings per Common Share, Diluted (C$/share) | 0.19 | 0.32 | 0.45 | 0.52 | 0.84 | 3 |
| Net Debt4 | 3,136 | 3,449 | 2,838 | 3,136 | 2,838 | |

1 Production before royalties reflects Nexen's working interest before royalties. Nexen has presented its working interest before royalties as it measures its performance on this basis consistent with other Canadian oil and gas companies. Nexen reports bitumen as production at Long Lake.

2 Cash flow from operations is a non-GAAP measure and is reconciled to the nearest GAAP measure on page II-200.

3 Includes results of discontinued operations. See Note 23 of Nexen's 2011 Consolidated Financial Statements.

4 Net debt is a non-GAAP measure and is reconciled to the nearest GAAP measure on page II-201.

First Quarter of 2012

Cash flow from operations rose 15% compared to the fourth quarter of 2011, reflecting cash netbacks from oil and gas operations that rose 7% to C$45.81/boe (after-tax) from stronger oil prices and increased production in higher-netback areas such as the UK North Sea. Nexen continued to benefit from strong Brent prices as approximately 70% of its oil production is priced off Brent. During the quarter, Brent averaged US$119.13/bbl and WTI averaged US$102.93/bbl, both increasing 9% from the previous quarter.

Nexen's first quarter production of 202,000 boe/d met its guidance of 180,000 to 220,000 boe/d. Operational performance was good across Nexen's asset base, except at Syncrude, where production was reduced due to unplanned maintenance. Production before royalties in the quarter was 3% below the previous quarter. The impact of the Yemen Masila contract expiration was largely offset by higher production from Long Lake, improved reliability at Buzzard in the UK North Sea, as well as first oil at Usan, offshore Nigeria. Long Lake production in the first quarter reached 34,500 boe/d gross (22,400 boe/d net to Nexen), a 10% increase over the prior quarter.

Capital investment during the quarter included development activities at Usan, which came on-stream in February and currently has seven wells on production. In the US Gulf of Mexico, Nexen achieved its second drilling success at Appomattox and added 50 mmboe of net contingent resource from the northeast fault block. At Long Lake, Nexen received regulatory approvals to proceed with pads 14, 15 and Kinosis 1A (K1A). Investment in the UK North Sea progressed projects at Golden Eagle, Rochelle and Telford, and Nexen commenced exploration drilling at the BP-operated North Uist prospect, west of the Shetland Islands. At Horn River in northeast British Columbia, Nexen completed drilling on its first 18-well pad with production expected to come on-stream in the fourth quarter of 2012.

Second Quarter of 2012

Cash flow from operations increased 6% compared to the prior quarter, reflecting solid production from key assets. Second quarter production of 213,200 boe/d met Nexen's guidance of 190,000 to 235,000 boe/d. Production before royalties was 5% above the previous quarter, driven by higher production from Buzzard in the UK North Sea and the ramp-up of production at Usan, offshore Nigeria. Long Lake production was 33,700 boe/d gross (21,900 boe/d net to Nexen), slightly below the prior quarter.

Cash netbacks were fairly consistent with the first quarter as growth in Nexen’s high-netback Usan production offset lower oil prices. Brent crude benchmark prices decreased 9% from the first quarter to average US$108.66/bbl. As approximately 75% of Nexen’s crude portfolio is priced based on Brent benchmarks, Nexen continues to benefit from strong Brent pricing.

Net income decreased 36% from the prior quarter as it includes C$123 million of pre-tax dry hole costs for the Kakuna exploration well in the US Gulf of Mexico.

Capital investment during the second quarter included development activities at Usan, offshore Nigeria and in the UK North Sea at Golden Eagle, Rochelle and Telford.

At Long Lake, oil production began on pad 12 late in the second quarter. Pad 13 is currently steaming with first production expected later in this year.

2. Financial Results

Change in Net Income

| (C$ millions) | 2012 vs 2011 Three Months Ended June 30 | Six Months Ended June 30 | |
|---|---|---|---|
| Net Income at June 30, 2011 | 252 | 454 | 1 |
| Favorable (unfavorable) variances2: | | | |
| Production Volumes, After Royalties | | | |
| Crude Oil | 326 | 245 | |
| Natural Gas | (12) | (34) | |
| Changes in Crude Oil Inventory For Sale | (6) | 19 | |
| Total Volume Variance | 308 | 230 | |
| Realized Commodity Prices | | | |
| Crude Oil | (118) | 81 | |
| Natural Gas | (35) | (58) | |
| Total Price Variance | (153) | 23 | |
| Operating Expense | (36) | (13) | |
| Depreciation, Depletion, and Amortization | (153) | (178) | |
| Exploration Expense | (62) | 4 | |
| Corporate Expense3 | (1) | 11 | |
| Income Taxes | (71) | 80 | |
| Non-recurring Events | | | |
| Gain on Asset Dispositions | 45 | 45 | |
| Prior Year Gain on Disposition and Loss on Debt Redemption and Repurchase | 1 | (257) | |
| Other | (21) | (119) | |
| Net Income at June 30, 2012 | 109 | 280 | |

1 Includes results of discontinued operations. See Note 23 of Nexen's 2011 Consolidated Financial Statements.

2 All amounts are presented before provision for income taxes.

3 Includes general & administrative expense, stock-based compensation expense, finance costs and energy marketing results.

Significant variances in net income are explained in the sections that follow.

First Quarter of 2012

Lower Volumes Reduced Net Income for the Quarter by C$78 Million

Production before and after royalties decreased approximately 13% and 7%, respectively, compared to the first quarter of 2011, primarily as a result of the Yemen Masila contract expiry and reduced gas production in the US Gulf of Mexico due to maintenance and natural declines. These reductions were partially offset by production increases from Long Lake, shale gas in western Canada, the UK North Sea, as well as new production from Usan, offshore Nigeria.

Production before royalties decreased 3% when compared to the fourth quarter of 2011. Production after royalties was comparable with the prior quarter, as the impact of the Yemen Masila contract expiration was less significant on an after-royalties basis.

United Kingdom

In the UK North Sea, quarterly production averaged 110,900 boe/d, 8% higher than both the previous quarter and the first quarter of 2011 due to improved reliability at Buzzard and higher rates from Nexen's other UK fields.

Buzzard averaged 82,100 boe/d (190,000 boe/d gross) for the quarter, slightly higher than the fourth quarter of 2011 and 16% higher than the same period last year as production returned to normal levels following maintenance and operational downtime in 2011.

Ettrick/Blackbird production averaged 17,300 boe/d during the quarter, up 12% from the previous quarter and the first quarter in 2011. This reflects increased production from the Blackbird field, which came on-stream in November 2011.

Production at Scott/Telford averaged 11,500 boe/d, up 67% from the fourth quarter. The Scott platform experienced downtime during the fourth quarter and early in the first quarter to tie-in the Telford TAC well.

Oil Sands – Long Lake

Production at Long Lake averaged 22,400 bbls/d (34,500 bbls/d gross), up 5,800 bbls/d from the same period in 2011, and 1,950 bbls/d from the prior quarter as Nexen continued to ramp-up pad 11 and carried on well optimization activities on the first ten pads.

Oil Sands – Syncrude

Syncrude production averaged 21,300 bbls/d for the quarter, 17% higher than the fourth quarter of 2011, primarily due to the completion of the Coker 8-2 turnaround in October and repairs to Hydrogen Plant 9-4.

Bitumen circulation problems with Coker 8-1 temporarily reduced production in both quarters. In March, Coker 8-1 was down for maintenance and the unit was back on production by mid-April. Production was 8% lower than the same period last year due to these unscheduled repairs.

United States

Production in US Gulf of Mexico averaged 16,300 boe/d, 11% lower than the prior quarter and 38% lower than the same period last year. Production at Longhorn was reduced by higher water production.

Canada

Production in Canada increased 6% from last quarter to average 21,900 boe/d, due to shale gas volume increases. Shale gas production at Horn River averaged 56 mmcf/d, 23% higher than the previous quarter, as production from the nine-well pad that came on-stream in October 2011 contributed for the full quarter.

Production decreased 3% from the same period last year due to declines in Nexen's conventional coal bed methane and gas properties in western Canada.

Nigeria

First oil at Usan, offshore Nigeria was achieved in late February 2012. Production for the quarter averaged 2,600 bbls/d (net to Nexen) and Nexen has ramped-up to rates of over 100,000 bbls/d (20,000 bbls/d net to Nexen) since then.

Other Countries

Nexen produced approximately 5,000 bbls/d from Block 51 in Yemen during the first quarter. Production last year included volumes from the Masila field. Nexen's Masila contract with the Yemen government expired in December 2011.

Nexen's share of production from the Guando field in Colombia averaged 1,500 bbls/d for the quarter. This was 6% lower than the prior quarter and 17% lower than the same period last year, primarily due to natural field declines.

Higher Commodity Prices Increased Quarterly Net Income C$176 Million

Crude oil prices remained strong during the quarter. Brent and WTI benchmark prices increased 9% from the prior quarter to average US$119.13/bbl and US$102.93/bbl, respectively, with the Brent/WTI premium increasing 6% to US$16.20/bbl. Approximately 70% of Nexen's oil production is sold based on Brent prices. Compared to the first quarter of 2011, Brent increased 13% and WTI was 9% higher. Nexen realized an average crude oil price of C$111.62/bbl in the quarter. This is 13% higher than the same period last year and 3% higher than the previous quarter.

Nexen's realized natural gas price was 14% lower than the previous quarter, averaging C$3.13/mcf, which reflects weak North American natural gas prices. NYMEX averaged US$2.51/mmbtu and AECO averaged C$2.39/mcf. Compared to the first quarter of 2011, Nexen's realized gas price decreased 31% as strong gas prices in the UK were offset by significant declines in AECO and NYMEX benchmark prices.

Lower Operating Expenses Increased Net Income by C$23 Million for the Quarter

Operating costs were 7% lower than the same period last year due to lower energy costs and the Masila contract expiry in Yemen. Per-unit operating costs increased compared to last year, primarily due to a change in production mix with the elimination of Masila production. This change in production mix increased Nexen's corporate average by C$2.68/boe.

Per-unit operating costs in the UK North Sea were impacted by higher Buzzard tariff costs and reduced production volumes during the Telford TAC tie-in.

In North America, reduced production volumes and higher fixed costs increased per-unit operating costs.

Long Lake per-unit operating costs decreased as a result of higher production volumes and lower natural gas costs. At Syncrude, lower energy costs and lease development costs reduced per-unit operating costs.

In other countries, a combination of fixed operating costs with lower production volumes due to natural declines increased per-unit operating costs.

The weaker Canadian dollar increased Nexen's corporate average operating expense by C$0.12/boe as operating costs of Nexen's international and US assets are denominated in US dollars.

Higher Oil and Gas Depreciation, Depletion, Amortization and Impairment (DD&A) Reduced Quarterly Net Income by C$25 Million

DD&A increased C$25 million or 7% from the same period last year. On a per-unit basis, DD&A increased C$3.47/boe, primarily as a result of changes in production mix and depletion rate increases in the UK North Sea and Long Lake. This was partially offset by lower rates at natural gas properties in Canada and the US Gulf of Mexico. A weaker Canadian dollar increased Nexen's corporate average by C$0.24/boe, as depletion of Nexen's international and US assets are denominated in US dollars.

In the UK, depletion rates at Blackbird, which came on-stream in November 2011, increased DD&A/boe. The initial Blackbird depletion rate is high as a portion of the proved reserves are classified as undeveloped and not yet used to deplete capitalized costs.

Canadian and US natural gas properties were impaired on December 31, 2011, reducing the North American DD&A rate in 2012.

At Long Lake, Nexen's depletion rate increased as a result of lower proved producing reserves used for depletion calculations. This decrease in reserves for depletion purposes was a result of revisions to Nexen's expectations of bitumen recoverability from the producing wells.

Lower Exploration Expense Increased Net Income for the Quarter by C$66 Million

Nexen continued to focus its exploration in its core basins in the US Gulf of Mexico, the UK North Sea, offshore Nigeria and Canada. Exploration drilling activity currently underway includes Kakuna and Appomattox in the US Gulf of Mexico and in the UK North Sea, North Uist, west of the Shetland Islands and the Stingray prospect, located northeast of the Scott platform.

Exploration expenses decreased C$66 million from the first quarter of 2011. Other exploration costs during the first quarter of 2012 were 71% lower than the same period last year, largely due to a reduction in lease rental expenses and unutilized drilling rig costs in the US Gulf of Mexico and Norwegian North Sea. Seismic costs increased C$19 million compared to the same period last year due to shale gas exploration activities in Canada and Poland. Seismic data costs will fluctuate from period to period depending on where Nexen is in the evaluation process.

Higher General and Administrative (G&A) Costs Decreased Quarterly Net Income by C$19 Million

G&A expense in the quarter increased 18% from the same period last year as a result of higher employee costs, slightly offset by lower stock-based compensation costs.

As Nexen accounts for stock-based compensation using the fair-value method, fluctuations in its share price create volatility in net income. During the quarter, Nexen's share price increased 10% and Nexen expensed approximately C$26 million of non-cash stock-based compensation (2011 – C$27 million), while cash payments made in connection with its programs decreased to nil (2011 – C$5 million).

Lower Finance Costs Increased Net Income by C$12 Million for the Quarter

Lower interest expenses reduced total finance costs by 16% compared to the first quarter of 2011. Interest costs are lower as a result of a reduction of approximately C$800 million in long-term debt.

Capitalized interest relates to costs for Nexen's Golden Eagle and in situ oil sands development projects.

Lower Taxes Increased Net Income by C$151 Million for the Quarter

Higher income from operations compared to the same period last year increased Nexen's income tax expense for the period. As compared to the prior year, Nexen's income was generated in higher tax rate jurisdictions. However, this income is partially offset by losses from lower tax rate areas which results in an overall higher tax expense for the period. Nexen's income tax provision includes current taxes in the United Kingdom, Yemen and Colombia.

In the first quarter of 2011, Nexen recorded a one-time, non-cash charge of C$270 million related to the increase in the UK supplementary charge tax rate on North Sea oil and gas activities to 62%. Additionally, the 2011 income tax expense includes C$51 million of deferred tax expense on discontinued operations.

The UK government intends to introduce legislation to restrict relief for decommissioning expenses to the previous 50% income tax rate. If this further change is enacted, an additional non-cash charge to net income of approximately C$50 to C$60 million will be required.

Strong Contribution from Energy Marketing Increased Net Income by C$19 Million during the Quarter

Nexen's energy marketing business continues to provide solid results. Nexen secured 18,000 bbls/d of long-term pipeline capacity to the west coast of Canada through the Trans Mountain pipeline. This allowed Nexen to generate an additional C$40 million of cash flow during the quarter as Nexen is now able to realize Brent-linked pricing for an otherwise heavily discounted Canadian crude oil.

Other

Nexen purchases crude oil put options to provide a base level of price protection without limiting its upside to higher prices. As a result, changes in forward crude prices create gains or losses on the options at each period end. For the quarter ended, rising oil prices resulted in a fair value loss of C$36 million (2011 – C$7 million) on these put options.

In February 2011, Nexen completed the sale of its 62.7% investment in Canexus for net proceeds of C$458 million realizing a gain on disposition of C$348 million.

In March 2011, Nexen incurred a C$39 million loss to repurchase and cancel US$312 million of notes due in 2015 and 2017. Approximately 90% of the loss represented the difference between market value and the carrying value of the bonds as a result of lower interest rates. In March 2011, Nexen also accrued a C$51 million loss on the early redemption call of the US$500 million of notes due in 2013 for the difference between amortized cost and the expected redemption price.

Second Quarter of 2012

Higher Volumes Increased Net Income for the Quarter by C$308 Million

Production before and after royalties increased approximately 4% and 15% compared to the second quarter of 2011. Improved uptime at Buzzard in the UK North Sea and production from Usan, offshore Nigeria more than offset lost production from the Yemen Masila contract expiry. Compared to the previous quarter, production before and after royalties increased 5% and 8% respectively, as Usan production ramped-up during the quarter.

Conventional Oil & Gas

United Kingdom

In the UK North Sea, strong operating performance and reliability at Buzzard improved quarterly production. UK production averaged 114,200 boe/d, 3% higher than the first quarter of 2012 and 36% higher than the second quarter of 2011.

Buzzard averaged 83,700 boe/d, slightly higher than the previous quarter and 71% higher than the same period last year, with production efficiency of 88%. Production continues to meet expectations, following maintenance and operational downtime in 2011.

Production at Scott/Telford averaged 15,900 boe/d, 37% higher from the first quarter as a result of completing the East Telford flowline project and bringing the Telford TAC well on-stream. Compared to the second quarter of 2011, Scott/ Telford is down 13%, due to maintenance and testing of the Telford TAC well tie-in.

Ettrick/Blackbird production averaged 14,600 boe/d, down 16% from the first quarter and 7% from the second quarter in 2011. This reflects natural declines and planned maintenance.

North America

In North America, production decreased 10% from the first quarter and 25% from the same period last year due to declines in the US Gulf of Mexico. US production averaged 14,100 boe/d, 13% lower than the prior quarter and 43% lower than the same period last year. This was primarily due to higher water content in the Longhorn field.

Shale gas production at Horn River averaged 52,400 mcf/d, 36% higher than second quarter of 2011, reflecting the impact of additional pad drilling.

Other Countries

In Nigeria, production at Usan continued to ramp up in the quarter. Since late April, production rates have averaged between 100,000 and 110,000 bbls/d (20,000 and 22,000 bbls/d net to Nexen).

Oil Sands

Long Lake

Production at Long Lake averaged 21,900 bbls/d (33,700 bbls/d gross), up 3,800 bbls/d from the second quarter in 2011, and down slightly from the prior quarter. Growth from pad 11, which is currently producing approximately 6,000 bbls/d, was offset by steam outages and well downtime, primarily during April. Production in May and June averaged 23,000 bbls/d (35,400 bbls/d gross). First oil production from pad 12 began late in the second quarter, ahead of Nexen’s expectations. Pad 13 is currently steaming with first production expected later this year.

Syncrude

Scheduled plant turnaround and maintenance activities at Syncrude occurred in the second quarter, reducing production. Production averaged 17,200 bbls/d, 15% lower than the second quarter of 2011 and 19% lower than the prior quarter.

Lower Commodity Prices Decreased Quarterly Net Income by C$153 Million

During the second quarter, the Brent benchmark price decreased 9% to average US$108.66/bbl. This decreased Nexen’s realized average crude oil price by 8% to C$102.21/bbl, as approximately 75% of its crude sales are based on Brent prices. WTI decreased 9% from the first quarter, decreasing the Brent/WTI premium by 6% to US$15.17/bbl. Compared to the second quarter of 2011, Brent and WTI decreased 7% and 9%, respectively.

Nexen's realized natural gas price was 18% lower than the first quarter, as it continued to reflect weak North American gas prices and averaged C$2.58/mcf. Compared to the second quarter of 2011, Nexen's realized gas price decreased 46% due to declines in AECO and NYMEX benchmark prices.

The Canadian/US exchange rate averaged just below par during the quarter, a decrease of 4 cents relative to the second quarter of 2011. This change increased Nexen's sales by approximately C$68 million.

Higher Operating Expenses Decreased Net Income by C$36 Million for the Quarter

Operating costs were 11% higher than the second quarter of last year. New production at Usan, offshore Nigeria and cost increases in the UK North Sea offset decreases at Long Lake.

Higher production and timing of sales in the UK North Sea increased operating costs. Per-unit operating costs at Ettrick and Scott/Telford in the UK North Sea were impacted by additional sub-sea maintenance, diesel consumption and volume-driven tariff increases.

In North America, reduced production volumes combined with relatively fixed costs increased per-unit operating costs.

Long Lake per-unit operating costs decreased as a result of higher production volumes, less down-hole maintenance, and reduced gas prices. Per-unit rates increased at Syncrude as a result of reduced production during the scheduled turnaround.

The weaker Canadian dollar increased Nexen's corporate average operating expense by C$0.30/boe as operating costs of its international and US assets are denominated in US dollars.

Higher Oil and Gas DD&A Reduced Quarterly Net Income by C$153 Million

DD&A increased C$153 million from the second quarter of last year primarily as a result of higher production in the UK North Sea and the start-up of the Usan development, offshore Nigeria. Overall, per-unit DD&A rates increased over 2011 as new higher-cost developments such as Usan replace production from the Masila field in Yemen. While the Usan DD&A rate is initially high, Nexen expects this rate will decrease as development converts reserves to proved developed reserves, which are used for DD&A. In the UK, depletion rates at Blackbird, which came on-stream in November 2011, increased DD&A per boe. The initial Blackbird depletion rate is high as a portion of the proved reserves are classified as undeveloped and not yet used to deplete capitalized costs.

At Long Lake, the depletion rate increased as a result of lower proved producing reserves used for depletion calculations. This decrease in reserves for depletion purposes was a result of Nexen's 2011 revisions to its expectations of bitumen recoverability from some of the producing wells.

Increased Exploration Expense Decreased Net Income for the Quarter by C$62 Million

Nexen focuses its exploration activities in its core basins in the US Gulf of Mexico, the UK North Sea, offshore Nigeria and Canada. Exploration and appraisal drilling activity currently underway includes Appomattox in the US Gulf of Mexico, North Uist, west of the Shetland Islands in the UK North Sea and Owowo West on block OPL-223 offshore Nigeria.

Exploration expenses increased C$62 million from the second quarter of 2011 primarily due to C$123 million of unsuccessful drilling costs related to the Kakuna exploration well in the US Gulf of Mexico.

Other exploration costs decreased C$56 million from the second quarter of 2011. In 2011, other exploration expense included non-recurring lease rental expenses and unutilized drilling rig costs related to the US Gulf of Mexico and the Norwegian North Sea.

Higher G&A Costs Decreased Quarterly Net Income by C$39 Million

G&A expense before stock-based compensation increased 11% from the second quarter of last year as a result of higher employee-related costs.

Nexen accounts for stock-based compensation using the fair-value method and fluctuations in Nexen's share price create volatility in net income. During the second quarter of 2012, Nexen's share price decreased 8% and it recovered C$2 million of non-cash stock-based compensation recognised in prior periods. During the second quarter of 2011, Nexen's share price decreased 10% and it recovered C$30 million of non-cash stock-based compensation. Cash payments made in connection with Nexen's programs were nil during the quarter.

Increased Finance Costs Decreased Net Income by C$21 Million for the Quarter

Finance costs increased by 35% compared to the second quarter of 2011, primarily due to lower capitalized interest. Nexen ceased capitalization on the Usan project in February 2012 once it came on-stream. Current capitalized interest relates to costs for Nexen's Golden Eagle project in the UK North Sea and in situ oil sands development projects.

Strong Contribution from Energy Marketing Increased Net Income by C$59 Million for the Quarter

Nexen's energy marketing business continues to provide solid results. In the first quarter of 2012, Nexen secured 18,000 bbls/d of long-term pipeline capacity to the west coast of Canada on the Trans Mountain pipeline. This allowed Nexen to generate C$34 million during the second quarter as it is able to realize Brent-linked pricing for otherwise heavily discounted Canadian crude oil.

Higher Taxes Decreased Net Income by C$71 Million for the Quarter

The effective tax rate increased to 79% as Nexen has increased income in high tax rate jurisdictions, while reducing Nexen's income in low tax jurisdictions. Nexen's income tax provision includes current taxes in the United Kingdom, Yemen and Colombia.

In the first quarter of 2011, Nexen recorded a one-time, non-cash charge of C$270 million related to the increase in the UK supplementary charge tax rate on North Sea oil and gas activities to 62%. Additionally, the 2011 income tax expense includes C$51 million of deferred tax expense on discontinued operations.

On July 3, 2012, the UK government legislation to restrict relief for decommissioning expenses to the previous 50% income tax rate became substantively enacted for accounting purposes. This change will result in an additional non-cash charge to net income of approximately C$60-65 million in Nexen's third quarter results.

Other

Nexen disposed non-core leases in Canada during the second quarter and recognized a gain of C$45 million.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

Segmented Cash Flow from Operations1

| (C$ millions) | Three Months Ended June 30 2012 | 2011 | Six Months Ended June 30 2012 | 2011 |
|---|---|---|---|---|
| Conventional Oil and Gas | | | | |
| United Kingdom | 919 | 699 | 1,984 | 1,586 |
| North America | 15 | 91 | 53 | 156 |
| Other Countries | 165 | 173 | 184 | 311 |
| Oil Sands | | | | |
| Long Lake | 4 | 6 | 22 | (13) |
| Syncrude | 70 | 103 | 161 | 210 |
| | 1,173 | 1,072 | 2,404 | 2,250 |
| Interest, Marketing and Other Corporate Items | (70) | (90) | (151) | (175) |
| Income Taxes | (396) | (384) | (876) | (808) |
| Total Cash Flow From Operations | 707 | 598 | 1,377 | 1,267 |

1 Cash flow from operations is a non-GAAP measure and is reconciled to the nearest GAAP measure on page II-200.

Compared to the second quarter of 2011, cash flow from operations increased 18%, driven by strong performance in the UK and first cash flow from Nigeria. These increases were partially offset by low North American natural gas prices, the expiry of the Masila contract in Yemen and a scheduled turnaround at Syncrude.

3. Liquidity and Capital Resources

Capital Structure

| (C$ millions) | June 30 2012 | December 31 2011 |
|---|---|---|
| Net Debt1 | | |
| Public Senior Notes2 | 3,936 | 3,929 |
| Subordinated Debt | 455 | 454 |
| Total Debt | 4,391 | 4,383 |
| Less: Cash and Cash Equivalents | (1,255) | (845) |
| Total Net Debt | 3,136 | 3,538 |
| Equity at Book Value | 8,839 | 8,373 |

1Includes all of Nexen's debt and is calculated as long-term debt and short-term borrowings less cash and cash equivalents. Net debt is a non-GAAP measure and is reconciled to the nearest GAAP measure on page II-201.

2The only debt maturity in the next five years is Nexen's US$126 million notes, which mature in March 2015.

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Liquidity

As at June 30, 2012, Nexen had liquidity of approximately C$4.8 billion (December 31, 2011-C$4.2 billion), comprised of cash and undrawn term credit facilities. At June 30, 2012, Nexen has committed term credit facilities of C$3.8 billion (December 31, 2011-C$3.8 billion), of which, C$232 million is utilized to support letters of credit (December 31, 2011-C$367 million). Nexen also has C$370 million of uncommitted credit facilities available (December 31, 2011– C$372 million).

Change in Net Debt

Changes in net debt for the three and six months ended June 30, 2012 are related to:

| (C$ millions) | Three Months Ended June 30 | Six Months Ended June 30 |
|---|---|---|
| Capital Investment | (743) | (1,500) |
| Cash Flow from Operations1 | 707 | 1,377 |
| Net Cash Flow Generated (Used) | (36) | (123) |
| Proceeds from Asset Dispositions | 46 | 53 |
| Issue of Preferred Shares, Net of Expenses | – | 195 |
| Issue of Common Shares | 8 | 26 |
| Dividends on Common Shares | (27) | (53) |
| Changes in Restricted Cash | (82) | (56) |
| Foreign Exchange Translation of US-dollar Debt and Cash | (64) | 4 |
| Net Change in Working Capital | 469 | 365 |
| Other | (1) | (9) |
| Decrease in Net Debt | 313 | 402 |

1 Cash flow from operations is a non-GAAP measure and is reconciled to the nearest GAAP measure on page II-200.

Nexen’s net debt levels are directly related to its operating cash flows and its capital expenditure activities. Nexen exited the quarter with net debt of C$3.1 billion; approximately C$400 million lower than December 31, 2011.

Contractual Obligations, Commitments and Guarantees

Nexen assumes various contractual obligations and commitments in the normal course of its operations. During the first half of the year, Nexen entered into commitments comprised of the following.

| | 2012 | 2013 | 2014 | 2015 | 2016 | Thereafter |
|---|---|---|---|---|---|---|
| Transport, Processing and Storage Commitments | 13 | 22 | 36 | 36 | 36 | 335 |
| Drilling Rig Commitments | 47 | 131 | 49 | – | – | – |

The commitments above are in addition to those included in Note 19 to the 2011 Audited Consolidated Financial Statements.

Non-GAAP Measures

Cash flow from operations is a non-GAAP measure defined as cash flow from operating activities before changes in non-cash working capital and other, and excludes items of a non-recurring nature. Nexen evaluates its performance and that of its business segments based on earnings and cash flow from operations. Nexen considers it a key measure as it demonstrates its ability and the ability of its business segments to generate the cash flow necessary to fund future growth through capital investment and repay debt. Cash flow from operations is unlikely to be comparable with the calculation of similar measures for other companies.

Cash Flow from Operations

| | Three Months Ended | | | Six Months Ended | |
|---|---|---|---|---|---|
| (C$ millions) | June 30 2012 | March 31 2012 | June 30 2011 | June 30 2012 | June 30 2011 |
| Cash Flow from Operating Activities | 1,159 | 508 | 1,020 | 1,667 | 1,750 |
| Changes in Non-Cash Working Capital | (446) | 146 | (419) | (300) | (485) |
| Other | 6 | 28 | 5 | 34 | 18 |
| Impact of Annual Crude Oil Put Options | (12) | (12) | (8) | (24) | (16) |
| Cash Flow from Operations | 707 | 670 | 598 | 1,377 | 1,267 |

Net debt is a non-GAAP measure defined as long-term debt and short-term borrowings less cash and cash equivalents. Nexen uses net debt as a key indicator of its leverage and to monitor the strength of its balance sheet. Net debt is directly tied to Nexen's operating cash flows and capital investment. Net debt is unlikely to be comparable with the calculation of similar measures for other companies.

Net Debt

| (C$ millions) | June 30 2012 | March 31 2012 | June 30 2011 |
|---|---|---|---|
| Public Senior Notes | 3,936 | 3,859 | 3,720 |
| Subordinated Debt | 455 | 446 | 430 |
| Total Debt | 4,391 | 4,305 | 4,150 |
| Less: Cash and Cash Equivalents | (1,255) | (856) | (1,312) |
| Total Net Debt | 3,136 | 3,449 | 2,838 |

## 6. Contingent Liabilities

There are a number of lawsuits and claims pending, the ultimate result of which cannot be ascertained at this time. Nexen records costs as they are incurred or become determinable. Nexen believes the resolution of these matters would not have a material adverse effect on its liquidity, consolidated financial position or results of operations. These matters are described in the section entitled "Legal Proceedings and Regulatory Actions" on page 60 of Nexen's 2011 AIF as set out in Appendix IV. There have been no significant developments since year-end.

Year Ended 31 December 2011 Compared to Year Ended 31 December 2010

The following should be read in conjunction with the Consolidated Financial Statements of Nexen as at and for the year ended December 31, 2011 as set out in the section entitled "Appendix II – Financial Information of Nexen Group – Published Financial Information of Nexen Group for Each of the Three Years ended 31 December 2009, 2010 and 2011 and the Six Months Ended 30 June 2012". The Consolidated Financial Statements of Nexen have been prepared in accordance with IFRS. The date of this discussion is February 15, 2012.

1. Executive Summary

| (C$ millions, except otherwise indicated) | 2011 | 2010 |
|---|---|---|
| Production before Royalties1,2 (mboe/d) | 207 | 246 |
| Production after Royalties2 (mboe/d) | 186 | 220 |
| Total Revenues and Other Income2 | 6,853 | 7,266 |
| Cash Flow from Operations2,3 | 2,368 | 2,150 |
| Net Income2 | 697 | 1,127 |
| Earnings per Common Share, Basic2 (C$/share) | 1.32 | 2.15 |
| Earnings per Common Share, Diluted2 (C$/share) | 1.24 | 2.09 |
| Dividend (C$/share) | 0.20 | 0.20 |
| Total Assets | 20,068 | 19,647 |
| Net Debt4 | 3,538 | 4,085 |

1Production before royalties reflects Nexen's working interest before royalties. Nexen has presented its working interest before royalties as it measures its performance on this basis consistent with other Canadian oil and gas companies. At Long Lake, Nexen reports bitumen as production.

2 Includes results of discontinued operations (see Note 23 of Nexen's 2011 Consolidated Financial Statements).

3 Cash flow from operations is a non-GAAP measure and is reconciled to the nearest GAAP measure on page II-214.

4 Net debt is a non-GAAP measure and is reconciled to the nearest GAAP measure on pageII-215.

High oil prices contributed to strong financial results in 2011. Cash flow from operations was C$2.4 billion and net income was C$697 million. Cash flow from operations reached its highest level since 2008 as Nexen's weighting to crude oil prices, in particular to Brent crude oil, allowed the company to realize strong cash netbacks. Earnings for 2011 were also strong, despite non-recurring expenses of C$322 million related to impairment charges and C$253 million related to costs associated with Nexen's shift away from large, integrated upgrading projects in its future oil sands development strategy.

Production averaged 207,000 boe/d in 2011, 16% below 2010. Operational issues at Buzzard in the UK North Sea through the first nine months of the year, natural field declines in Yemen and the disposition of Nexen's heavy oil assets in 2010 were the primary reason for the reduction. Production in 2010 included about 9,000 boe/d from heavy oil properties, which were sold in the third quarter of 2010. Fourth quarter 2011 production averaged 208,000 boe/d, 22,000 boe/d higher than the third quarter. This increase was due to improved uptime at Buzzard, new production from the Blackbird field and increases in production at Long Lake and Horn River shale gas. On December 17, 2011, Nexen's production sharing agreement expired on the Masila block in Yemen and the assets were transferred to the Yemen Government.

Crude oil prices continued an upward trend in 2011 with Brent increasing 40% and WTI increasing 20% from 2010. The Brent/WTI premium widened to average US$16.16/bbl for the year. The benefit of these high commodity prices was partially offset by the stronger Canadian dollar, which strengthened 4 cents in the year. Nexen's realized crude oil and gas prices increased 30% in 2011 and averaged C$91.46/boe. Cash netbacks from oil and gas operations increased from 2010 to average C$40.20/boe as a result of the higher prices.

Nexen's non-core asset disposition program generated proceeds of C$518 million and net pre-tax gains of C$386 million in 2011. This follows a 2010 program which generated proceeds of C$1.3 billion and net pre-tax gains of C$787 million.

Net debt declined 13% in 2011 and 36% over the past two years, as proceeds from non-core asset dispositions were used to repay debt. During 2011, Nexen repurchased and cancelled approximately C$800 million of long-term debt. Nexen's available liquidity has increased and was C$4.2 billion at December 31, 2011, comprised of cash and undrawn committed credit facilities, most of which were available until 2016.

2. Financial Results

| (C$ millions) | 2011 vs 2010 |
|---|---|
| Net Income for 20101 | 1,127 |
| Favourable (Unfavourable) Variances:2 | |
| Production Volumes, After Royalties | |
| Crude Oil | (855) |
| Natural Gas | (32) |
| Change in Crude Oil Inventory | 94 |
| Total Volume Variance | (793) |
| Realized Commodity Prices | |
| Crude Oil | 1,365 |
| Natural Gas | (20) |
| Total Price Variance | 1,345 |
| Oil & Gas Operating Expense | (45) |
| Oil & Gas Depreciation, Depletion, Amortization and Impairment | (270) |
| Exploration Expense | (40) |
| Net Gain on Dispositions and Loss on Debt Redemption and Repurchase | (492) |
| Energy Marketing Contribution | 59 |
| Canexus3 | (58) |
| General and Administrative Expense | 174 |
| Finance Costs | 131 |
| Provision for Income Taxes | (479) |
| Other | 38 |
| Net Income for 20111 | 697 |

1 Includes results of discontinued operations (see Note 23 of Nexen’s 2011 Consolidated Financial Statements).

2 All amounts are presented before provision for income taxes.

3 Nexen disposed of its investment in Canexus in the first quarter of 2011 (see Note 23 of Nexen’s 2011 Consolidated Financial Statements).

Significant variances in net income are explained in the sections that follow.

Lower Volumes Decreased Net Income by C$793 Million

Production before and after royalties decreased approximately 16% from 2010 levels. Operational issues at Buzzard in the North Sea and natural field declines in Yemen were primary reasons for the decrease. Production in 2010 included about six months of volumes from heavy oil assets that were sold in the third quarter of 2010.

United Kingdom

UK production decreased 19% from 2010 to average 90,000 boe/d, primarily as a result of various operational issues at Buzzard. Buzzard production was 62,400 boe/d in 2011, 23% lower than 2010. Unplanned maintenance on the cooling system, third-party pipeline outages and delays in commissioning the fourth platform were the primary factors for the decrease.

Yemen

Production in Yemen decreased 20% compared to 2010, due to natural field declines, limited capital investment and the end of Nexen's Block 14 Masila production sharing agreement on December 17, 2011.

Syncrude

Syncrude production averaged 20,900 bbls/d for the year, consistent with 2010. Unscheduled repairs to Hydrogen Plant 9-4 temporarily reduced production in the fourth quarter of 2011.

Long Lake

Annual bitumen production increased 17% to average 28,600 bbls/d (18,600 bbls/d net to Nexen).

United States

Production in the Gulf of Mexico averaged 22,600 boe/d in 2011, 14% below 2010, primarily as a result of natural field declines and to a lesser extent, downtime from Tropical Storm Lee.

Canada

After eliminating the impact of the sale of the heavy oil properties in 2010, production in Canada increased 3% in 2011. Shale gas production for the year averaged 38 mmcf/d, more than triple the previous year's production.

Other Countries

Production from Colombia decreased 400 bbls/d from 2010 to average 1,700 bbls/d in 2011, primarily as a result of natural field declines.

Higher Crude Oil Prices Increased Net Income by C$1,345 Million

Crude oil prices continued to strengthen in 2011 with Brent and WTI increasing 40% and 20%, respectively, over 2010 levels. Approximately 70% of Nexen's crude oil production is priced off of Brent. Brent traded at a premium to WTI reflecting significant inventory levels at Cushing, Oklahoma, which reduced

WTI prices relative to Brent. The stronger Canadian dollar reduced some of the impact of higher prices, as Nexen's realized crude oil price was C$105.21/bbl, 33% higher than 2010. In North America, NYMEX and AECO natural gas prices decreased 8% and 11% from 2010, respectively. Nexen's realized natural gas price decreased only 5% to average C$4.31/mcf, as a portion of its natural gas production is located in the UK North Sea where prices are higher.

The Canadian/US exchange rate averaged close to par during 2011, an increase of 4 cents relative to 2010. This change reduced sales by approximately C$250 million. Offsetting this impact, Nexen's US-denominated operating expenses and capital expenditures are lower when translated to Canadian dollars.

Higher Oil and Gas Operating Expenses Reduced Net Income by C$45 Million

Oil and gas operating costs increased 3% primarily due to operating cost pressures. On a per unit basis, operating costs increased 23% as a result of reduced production volumes. A significant portion of Nexen's operating costs are fixed and do not vary with production rates.

Unit operating costs at Long Lake are 17% lower than 2010 primarily as a result of higher production levels. Operating costs at Long Lake are primarily fixed in nature and increased bitumen production should continue to lower operating costs per boe.

In the UK North Sea, Buzzard's operating costs per boe increased as a result of additional maintenance activities and lower production. Elsewhere in the UK, maintenance costs at Scott and Ettrick resulted in higher operating costs.

In North America, operating costs per boe were consistent with 2010, reflecting higher costs in the US Gulf of Mexico offset by a reduction in Canada as a result of property dispositions in the third quarter of 2010. In Yemen, production declines, combined with higher costs, increased Nexen's corporate average by C$0.47/boe.

At Syncrude, the impact of higher maintenance costs increased Nexen's corporate average by C$0.36/boe.

The stronger Canadian dollar reduced Nexen's corporate average by C$0.10/ boe as operating costs for Nexen's International and US operations are denominated in US dollars.

Higher Oil and Gas DD&A Decreased Net Income by C$270 Million

Nexen's average per unit DD&A expense increased marginally from 2010. Changes in Nexen's production mix as a result of the sale of heavy oil properties in Canada, production disruptions at Buzzard and improved production rates at Long Lake were the primary reasons for the change.

Higher Exploration Expense Reduced Net Income by C$40 Million

Exploration expense increased 12% from 2010. Nexen’s exploration program is primarily focused on opportunities in the deep-water US Gulf of Mexico, UK North Sea, offshore West Africa and Canada. In 2011, Nexen drilled 11 wells, of which three were exploration and eight were appraisal.

Seismic expenditures decreased 26% compared to 2010. Lower spending in the US Gulf of Mexico, UK North Sea and Norway contributed to the reduction. This was offset by additional seismic acquisitions for Nexen’s shale gas plays in northeast British Columbia and Poland. Seismic data costs fluctuate depending on where Nexen is in its evaluation process.

Unsuccessful drilling costs were marginally higher than 2010 and represented 18% of Nexen’s exploration drilling capital. Nexen expensed C$30 million of exploration costs related to unsuccessful activities in the UK North Sea. Nexen expensed C$35 million of costs related to the Ronaldo exploration well in the Norwegian North Sea early in the year. Nexen has no further exploration planned in the Norwegian North Sea.

Other exploration costs were C$65 million higher than 2010, primarily due to unutilized drilling rig and service costs early in the year as a result of the drilling moratorium in the US Gulf of Mexico.

Oil & Gas Cash Netbacks

Cash netbacks are the cash margins Nexen receives for every equivalent barrel sold before general and administrative expenses. Nexen’s cash netbacks were 44% of realized sales prices in 2011. Cash netbacks at Long Lake improved since 2010 to average C$9.84/bbl in 2011. Increasing bitumen production is the primary contributor, as most of the operating costs are fixed in nature. Increases in Long Lake bitumen production volumes and higher upgrading yields should continue to reduce Nexen’s per unit operating cost and improve cash margins going forward.

The following table includes the sales prices, per-unit costs and netbacks for Nexen’s producing assets, calculated using Nexen’s working interest production before and after royalties.

Before Royalties1

| (C$/boe) | 2011 United Kingdom | Conventional North America | Other Countries2 | Oil Sands In Situ | Syncrude | Total Oil and Gas |
|---|---|---|---|---|---|---|
| Sales | 103.32 | 39.41 | 107.85 | 98.33 | 101.73 | 91.46 |
| Royalties and Other | (0.36) | (3.72) | (46.92) | (5.05) | (8.10) | (10.34) |
| Operating Expenses | (10.60) | (11.15) | (12.73) | (83.44) | (37.78) | (19.00) |
| In-country Taxes | (42.41) | – | (14.17) | – | – | (21.92) |
| Cash Netback | 49.95 | 24.54 | 34.03 | 9.84 | 55.85 | 40.20 |

| (C$/boe) | 2010 United Kingdom | Conventional North America | Other Countries2 | Oil Sands In Situ | Syncrude | Total Oil and Gas |
|---|---|---|---|---|---|---|
| Sales | 76.51 | 40.85 | 81.63 | 77.07 | 81.23 | 70.11 |
| Royalties and Other | – | (4.41) | (35.18) | (3.65) | (6.27) | (8.16) |
| Operating Expenses | (8.28) | (11.16) | (10.09) | (100.09) | (34.34) | (15.48) |
| In-country Taxes | (24.36) | – | (10.29) | – | – | (13.21) |
| Cash Netback | 43.87 | 25.28 | 26.07 | (26.67) | 40.62 | 33.26 |

1Before-royalty cash netbacks are calculated by dividing sales, royalties and other, operating expenses and in-country taxes by production before royalties. After-royalty cash netbacks are calculated by dividing sales, operating expenses and in-country taxes by production after royalties.

2 Includes results of conventional crude oil and natural gas operations in Yemen and Colombia.

After Royalties1

| (C$/boe) | 2011 United Kingdom | Conventional North America | Other Countries2 | Oil Sands In Situ | Syncrude | Total Oil and Gas |
|---|---|---|---|---|---|---|
| Sales | 103.32 | 39.41 | 107.85 | 98.33 | 101.73 | 91.46 |
| Operating Expenses | (10.64) | (12.20) | (22.54) | (90.22) | (40.94) | (21.30) |
| In-country Taxes | (42.56) | – | (25.07) | – | – | (24.58) |
| Cash Netback | 50.12 | 27.21 | 60.24 | 8.11 | 60.79 | 45.58 |

| | 2010 | | | | | |
|---|---|---|---|---|---|---|
| | | Conventional | | Oil Sands | | |
| (C$/boe) | United Kingdom | North America | Other Countries2 | In Situ | Syncrude | Total Oil and Gas |
| Sales | 76.51 | 40.85 | 81.63 | 77.07 | 81.23 | 70.11 |
| Operating Expenses | (8.28 ) | (12.38 ) | (17.83 ) | (105.25 ) | (37.18 ) | (17.40 ) |
| In-country Taxes | (24.38 ) | – | (18.17 ) | – | – | (14.85 ) |
| Cash Netback | 43.85 | 28.47 | 45.63 | (28.18 ) | 44.05 | 37.86 |

1Before-royalty cash netbacks are calculated by dividing sales, royalties and other, operating expenses and in-country taxes by production before royalties. After-royalty cash netbacks are calculated by dividing sales, operating expenses and in-country taxes by production after royalties.

2 Includes results of conventional crude oil and natural gas operations in Yemen and Colombia.

Lower G&A Costs Increased Net Income by C$174 Million

G&A costs decreased 37% from 2010, primarily due to lower employee costs and a recovery of stock-based compensation during the year. G&A expenses before stock-based compensation decreased C$110 million primarily due to non-recurring costs in 2010 related to non-core asset dispositions.

Changes in Nexen's share price create volatility in its net income as Nexen accounts for stock-based compensation using the fair-value method. During the year, Nexen recovered non-cash stock-based compensation costs of C$85 million as its stock price ended the year at C$16.21/share, compared to the previous year when it closed at C$22.80/share. This recovery was partially offset by cash payments for stock-based compensation programs of C$10 million, 62% lower than 2010.

Lower Finance Costs Increased Net Income by C$131 Million

Interest costs decreased C$75 million from 2010. This 20% decrease was the result of lower debt levels as Nexen used proceeds from its non-core asset dispositions to repay drawn term credit facilities, repurchase and cancel US$812 million of fixed-rate debt, and deconsolidate the debt associated with Canexus.

Capitalized borrowing costs were C$37 million higher than 2010. Borrowing costs are capitalized at Nexen's Usan project offshore West Africa, Golden Eagle in the UK North Sea and Kinosis in the oil sands. Nexen capitalized borrowing costs for the fourth platform at Buzzard in the UK North Sea until it was completed mid-year.

Higher Taxes Decreased Net Income by C$479 Million

In late March, the UK government increased the supplementary tax rate on North Sea oil and gas activities, which increased the UK statutory oil and gas income tax rate from 50% to 62%. This change increased Nexen's current income

tax expense by C$228 million in 2011 and increased its deferred income tax liabilities, resulting in a one-time, non-cash charge of C$270 million to net income.

Stronger commodity prices compared to the prior year also contributed to an increase to Nexen's income tax expense for the year. Nexen's income tax provision includes current taxes in the UK, Yemen, Norway, Colombia and the US.

Higher Marketing Contribution Increased Net Income by C$59 Million

Nexen's energy marketing business generated solid results in 2011. The higher contribution in 2011 relative to 2010 was primarily due to a reduction in the scope of Nexen's energy marketing business in 2010, which triggered one-time losses for disposed contracts in the third quarter of 2010. In addition, high power prices in Alberta contributed to improved results for Nexen's power generation facilities. Nexen generated C$11 million of proceeds from the disposition of the North America commercial and industrial power business in 2011.

Other

In 2011, Nexen realized net gains of C$386 million on the disposition of non-core assets consisting of the following:

62.7% investment in Canexus for net proceeds of C$458 million, realizing a gain of C$348 million; and

Duart field in the UK North Sea for proceeds of C$38 million, realizing a gain of C$38 million.

During 2011, Nexen paid C$525 million to redeem the US$500 million notes due in 2013. Nexen incurred a C$52 million loss on the transaction being the difference between carrying cost and the redemption price. Nexen also paid C$346 million to repurchase and cancel US$312 million of notes due in 2015 and 2017. Nexen incurred a C$39 million loss on the repurchase. Approximately 90% of the loss represents the difference between market value and the carrying value of the bonds.

Nexen purchases crude oil put options to provide a base level of price protection without limiting its upside to higher prices. These options settle monthly or annually and unexpired options are recorded at fair value throughout their term. As a result, changes in forward crude oil prices create gains or losses on the options at each period end. In 2011, Nexen recorded a fair value loss of C$23 million on these put options (2010-C$41 million loss).

3. Liquidity and Capital Resources

Capital Structure

| (C$ millions) | December 31 2011 | December 31 2010 |
|---|---|---|
| Net Debt1 | | |
| Public Senior Notes | 3,929 | 4,647 |
| Subordinated Debt | 454 | 443 |
| Total Debt | 4,383 | 5,090 |
| Less: Cash and Cash Equivalents | (845) | (1,005) |
| Total Net Debt2 | 3,538 | 4,085 |
| Nexen Inc. Shareholders' Equity | 8,373 | 7,814 |

1 Includes all of Nexen's debt and is calculated as long-term debt and short-term borrowings less cash and cash equivalents. Net debt is a non-GAAP measure and is reconciled to the nearest GAAP measure on page II-215.

2 December 31, 2010 excludes net debt related to Nexen's chemical operations that was included in assets and liabilities held for sale (see Note 23 of Nexen's 2011 Consolidated Financial Statements). Nexen's remaining interest was sold in February 2011 for net proceeds of C$458 million.

Net Debt

Nexen's net debt levels are directly related to its operating cash flows, capital expenditures and acquisition and divestiture activity. Nexen ended the year with net debt of C$3,538 million, C$547 million lower than December 31, 2010. Over the last two years, Nexen has reduced net debt by over C$2 billion primarily as a result of proceeds from the sale of non-core assets. The year-over-year change in Nexen's net debt results from:

| (C$ millions) | 2011 | 2010 |
|---|---|---|
| Capital Investment | (2,575) | (2,724) |
| Net Proceeds from Non-core Asset Dispositions | 518 | 1,262 |
| Cash Flow from Operations | 2,368 | 2,150 |
| | 311 | 688 |
| Dividends on Common Shares | (105) | (104) |
| Issue of Common Shares | 46 | 55 |
| Debt Repayment Costs | (91) | – |
| Change in Non-Cash Working Capital | 576 | 279 |
| Reclassification of Canexus Net Debt Related to Sale | – | 391 |
| Other | (173) | (35) |
| Foreign Exchange Translation of US-dollar Debt and Cash | (17) | 203 |
| Decrease in Net Debt | 547 | 1,477 |

During 2011, Nexen's net debt decreased primarily as a result of proceeds from the disposition of Canexus and working capital reductions, which were principally reductions in energy marketing inventories. Although not effecting net debt, Nexen also repurchased and cancelled US$812 million of long-term debt using cash on hand early in the year.

Change in Working Capital

| (C$ millions) | December 31 2011 | December 31 2010 | Increase (Decrease) |
|---|---|---|---|
| Cash and Cash Equivalents | 845 | 1,005 | (160) |
| Restricted Cash | 45 | 40 | 5 |
| Accounts Receivable | 2,247 | 1,789 | 458 |
| Net Current Derivative Contracts | 16 | (10) | 26 |
| Inventories and Supplies | 320 | 550 | (230) |
| Accounts Payable and Accrued Liabilities | (2,867) | (2,223) | (644) |
| Current Income Taxes Payable | (458) | (345) | (113) |
| Other | 115 | 133 | (18) |
| Total | 263 | 939 | (676) |

Nexen's working capital balances decreased significantly from 2010. Cash and cash equivalents decreased C$160 million as Nexen used proceeds from the disposition program and cash on hand to repurchase and cancel approximately C$800 million of long-term debt. Accounts receivable increased with higher oil prices and volumes in the fourth quarter, while inventories decreased due to a reduction in crude oil inventory late in the year. Accrued liabilities increased due to higher capital spending late in the year.

At December 31, 2011, Nexen's restricted cash consisted of margin deposits of C$45 million (2010-C$40 million) related to exchange-traded derivative financial contracts used by its energy marketing group to economically hedge physical commodities, storage, transportation and customer sales contracts. Nexen is required to maintain margin for net out-of-the-money derivative financial contracts.

Liquidity

At December 31, 2011, Nexen had liquidity of C$4.2 billion, comprised of cash and undrawn committed credit facilities. Nexen had committed term credit facilities of C$3.8 billion, of which C$367 million was utilized to support letters of credit. Of this, C$700 million is available until 2014 and C$3.1 billion is available until 2016. Nexen also had C$393 million of uncommitted credit facilities.

The following table shows how Nexen financed its business activities over the last five years. When Nexen's operating cash flows exceed its investment requirements, Nexen generally pays down debt or return cash to shareholders. Nexen borrows money or may issue equity to fund investment requirements that exceed its operating cash flow.

| (C$ millions) | 2011 | 2010 | 2009 [1] | 2008 [1] | 2007 [1] |
|---|---|---|---|---|---|
| Cash Flow from Operating Activities | 2,497 | 2,392 | 1,886 | 4,354 | 2,830 |
| Cash Flow from Investing Activities | (1,757) | (1,465) | (3,743) | (3,189) | (3,281) |
| Surplus (Deficiency) | 740 | 927 | (1,857) | 1,165 | (451) |
| Cash Flow from Financing Activities | (932) | (1,506) | 1,821 | 322 | 677 |
| Net Cash Generated (Used) | (192) | (579) | (36) | 1,487 | 226 |

1 Prior to 2011, Nexen's financial statements were prepared in accordance with previous Canadian GAAP. In the first quarter of 2011, Nexen adopted IFRS with an effective date as at January 1, 2010 and restated the 2010 financial results to be in accordance with IFRS. Further details regarding Nexen's transition to IFRS are included in Note 26 of 2011 Consolidated Financial Statements. As such, amounts prior to 2010 are presented in accordance with previous Canadian GAAP and have not been restated.

In 2009 and 2010, Nexen's non-core asset disposition program raised almost C$1.8 billion of proceeds. In 2010, Nexen repaid C$1.5 billion of term credit facilities using proceeds from its non-core asset disposition program. In 2011, Nexen repurchased and cancelled US$812 million of long-term debt using cash on hand.

Contractual Obligations, Commitments and Guarantees

Nexen assumes various contractual obligations and commitments in the normal course of its operations and financing activities. They include:

| (C$ millions) | Total | < 1 year | Payments 1-3 years | 4-5 years | > 5 years |
|---|---|---|---|---|---|
| Long-Term Debt | 4,463 | – | – | 128 | 4,335 |
| Cumulative Interest on Long-Term Debt | 6,978 | 301 | 601 | 589 | 5,487 |
| Operating Leases1 | 316 | 66 | 110 | 51 | 89 |
| Finance Leases | 82 | 4 | 8 | 8 | 62 |
| Energy Commodity Contracts | 127 | 103 | 23 | 1 | – |
| Transportation, Processing, and Storage Commitments1 | 461 | 99 | 153 | 80 | 129 |
| Work Commitments and Purchase Obligations2 | 1,583 | 1,099 | 414 | 34 | 36 |
| Asset Retirement Obligations | 3,481 | 67 | 114 | 246 | 3,054 |
| Total | 17,491 | 1,739 | 1,423 | 1,137 | 13,192 |

1Payments for operating leases and transportation, processing, and storage commitments are deducted from Nexen's cash flow from operating activities.

2Some of these payments relate to work commitments that Nexen can cancel without penalties or additional fees. Drilling rig commitments are disclosed net of C$102 million of subleases.

## 4. Non-GAAP Measures

Cash Flow from Operations

| (C$ millions) | December 31 2011 | December 31 2010 |
|---|---|---|
| Cash Flow from Operating Activities | 2,497 | 2,392 |
| Changes in Non-Cash Working Capital | (255) | (338) |
| Other | 158 | 128 |
| Impact of Annual Crude Oil Put Options | (32) | (32) |
| Cash Flow from Operations | 2,368 | 2,150 |

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

Net Debt

| (C$ millions) | December 31 2011 | December 31 2010 |
|---|---|---|
| Public Senior Notes | 3,929 | 4,647 |
| Subordinated Debt | 454 | 443 |
| Total Debt | 4,383 | 5,090 |
| Less: Cash and Cash Equivalents | (845 ) | (1,005 ) |
| Total Net Debt | 3,538 | 4,085 |

Year Ended 31 December 2010 Compared to Year Ended 31 December 2009

The following should be read in conjunction with the Consolidated Financial Statements of Nexen as at and for the year ended December 31, 2010 as set out in the section entitled “Appendix II – Financial Information of Nexen Group – Published Financial Information of Nexen Group for each of the Three Years ended 31 December 2009, 2010 and 2011 and the Six Months Ended 30 June 2012”. The 2010 Consolidated Financial Statements of Nexen have been prepared in accordance with Canadian GAAP. The date of this discussion is 16 February 2011.

1. Executive Summary

| (C$ millions, except otherwise indicated) | 2010 | 2009 | 2008 |
|---|---|---|---|
| Production before royalties (mboe/d)1, 2 | 246 | 243 | 250 |
| Production after royalties (mboe/d)2 | 220 | 213 | 210 |
| Total Revenues and Other Income2 | 7,226 | 5,804 | 8,237 |
| Cash Flow from Operations2, 3 | 2,130 | 2,215 | 4,229 |
| Net Income from Continuing Operations | 572 | 512 | 1,602 |
| Net Income2 | 1,197 | 536 | 1,715 |
| Earnings per Common Share from Continuing Operations, Basic (C$/share) | 1.09 | 0.98 | 3.05 |
| Earnings per Common Share from Continuing Operations, Diluted (C$/share) | 1.08 | 0.96 | 3.01 |
| Earnings per Common Share, Basic2 (C$/share) | 2.28 | 1.03 | 3.26 |
| Earnings per Common Share, Diluted2 (C$/share) | 2.27 | 1.01 | 3.22 |
| Cash Dividend (C$/share) | 0.2 | 0.2 | 0.18 |
| Total Assets | 21,907 | 22,900 | 22,155 |
| Net Debt4 | 4,074 | 5,551 | 4,575 |

1Production before royalties reflects Nexen’s working interest before royalties. Nexen has presented its working interest before royalties as it measures its performance on this basis consistent with other Canadian oil and gas companies. Nexen reports bitumen as production.

2 Includes results of discontinued operations (see Note 20 of Nexen’s 2010 Consolidated Financial Statements).

3 Cash flow from operations is a non-GAAP measure and is reconciled to the nearest GAAP measure on page II-230.

4 Net debt is a non-GAAP measure and is reconciled to the nearest GAAP measure on pageII-231.

Strong production rates and strengthening commodity prices delivered solid financial results in 2010 as cash flow from operations during the year exceeded C$2.1 billion and net income was approximately C$1.2 billion. Nexen's successful non-core asset disposition program generated proceeds of almost C$1.3 billion and net pre-tax gains of C$740 million in 2010.

WTI and Brent crude oil prices both increased 29% from the previous year to average about US$80/bbl. The benefit from these higher commodity prices was muted by the stronger Canadian dollar as the US/Canadian average exchange rate strengthened from 88 cents in 2009 to 97 cents in 2010. Nexen's realized oil and gas price increased 17% over the same period to average C$70.11/boe.

Production before royalties averaged 246,000 boe/d in 2010, up slightly from 2009. Excluding the impact from the sale of the heavy oil assets midway through the year, production increased 5% over 2009. A full year of production at Longhorn in the Gulf of Mexico and at Ettrick in the North Sea, and continued bitumen ramp-up at Long Lake, increased production volumes in 2010. UK production was higher than 2009 despite third-party facilities outages as well as planned downtime to commission the Buzzard fourth platform that temporarily reduced production.

For the past several years, Nexen invested significant capital in a number of major development projects such as Buzzard and Long Lake. With the bulk of investment in these projects completed and new production from Ettrick, Longhorn and Long Lake on stream, Nexen expects to fund its next generation of new growth projects from operating cash flows. These projects include Golden Eagle in the UK North Sea, Usan offshore West Africa (approximately 85% complete), future oil sands insitu phases and shale gas in the Horn River Basin in northeast British Columbia, as well as several exploration prospects.

Nexen's net debt decreased 25% or approximately C$1.5 billion during the year primarily as a result of Nexen's non-core asset disposition program.

As at December 31, 2010, Nexen's available liquidity was C$4 billion, comprised of cash and undrawn committed credit facilities, most of which was available until 2014.

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

2. Financial Results

Year-to-Year Change in Net Income

| (C$ millions) | 2010 vs 2009 | 2009 vs 2008 |
|---|---|---|
| Net Income for 2009 and 2008[1] | 536 | 1,715 |
| Favourable (unfavourable) variances:[2] | | |
| Production Volumes, After Royalties | | |
| Crude Oil | 244 | (137) |
| Natural Gas | 57 | 36 |
| Change in Crude Oil inventory | 0 | (80) |
| Total Volume Variance | 371 | (181) |
| Realized commodity Prices | | |
| Crude Oil | 711 | (1,871) |
| Natural Gas | 27 | (313) |
| Total Price Variance | 738 | (2,184) |
| Oil & Gas Operating Expense | (385) | 9 |
| Oil & Gas Depreciation, Depletion, Amortization and Impairment | 29 | 241 |
| Exploration Expense | (26) | 100 |
| Non-core Asset Disposition Gains | 740 | – |
| Energy Marketing Revenue, Net | (322) | 605 |
| Chemicals Contribution | (48) | 73 |
| General and Administrative Expense | 15 | (240) |
| Interest Expense | (12) | (218) |
| Current Income Taxes | (356) | 83 |
| Future Income taxes | (148) | 1,114 |
| Change in Fair value of Crude Oil Put Options | 210 | (454) |
| Other | (145) | (127) |
| Net Income for 2010 and 2009[1] | 1,197 | 536 |

1 Includes results of discontinued operations (see Note 20 of Nexen's 2010 Consolidated Financial Statements).

2 All amounts are presented before provision for income taxes.

Significant variances in net income are explained in the sections that follow.

Higher Volumes Increased Income by C$371 Million

Production before royalties averaged 246,000 boe/d, slightly higher than 2009. After adjusting for the impact of heavy oil volumes disposed midway through the year, production increased 5% over 2009. A full year of production at Ettrick in the North Sea and at Longhorn in the Gulf of Mexico, and higher

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bitumen production at Long Lake, offset natural declines in Yemen. Production after royalties increased 3% from 2009 to average 220,000 boe/d, as Nexen produced more from lower royalty jurisdictions.

United Kingdom

UK production for the year increased 9% from 2009 to average 110,700 boe/ d, primarily as a result of a full year of production at Ettrick, which came on stream mid 2009.

Buzzard production was down slightly from 2009 due to planned downtime to complete installation and commissioning of the H2S processing facilities on the fourth platform. Commissioning is proceeding well and Nexen is near to having it fully integrated with the existing production systems. With the increased H2S handling capability, Nexen expects to be able to continue to maintain its high netback Buzzard production at plateau for many more years. Nexen has identified drilling locations to continue its development program at Buzzard into 2013, which is expected to extend its production plateau.

A full year of production from Nexen's Ettrick field contributed 14,500 boe/ d to Nexen's annual average volumes. This was higher than 2009 when it averaged 4,300 boe/d, as the facilities came on stream in the third quarter of 2009.

Scott/Telford averaged 13,900 boe/d, 3% higher than 2009. The increased production from the successful step-out development well drilled in the third quarter of 2009 was offset by an eight week shut-in during the third quarter of 2010 due to a valve failure on the third-party owned Forties pipeline system. Production in the fourth quarter was also affected by the repairs on the gas export system, which have since been resolved. Production from Nexen's non-operated fields at Duart and Farragon averaged 1,800 boe/d in 2010.

Canada

Production in Canada decreased 25% in 2010 primarily as a result of the disposition of Nexen's heavy oil assets. Excluding the impact of the disposition, Canadian production decreased 5% from 2009. Coalbedmethane (CBM) production decreased 9% from 2009 due to natural declines, while Nexen's maturing natural gas fields in the Medicine Hat region and the Balzac field were down 12% as Nexen limited investment in conventional natural gas as a result of low natural gas prices.

Nexen continued to invest in shale gas in the Dilly Creek area of the Horn River Basin in northeast British Columbia. During the year, Nexen successfully completed a 144 frac program on Nexen's eight-well pad.

Long Lake

Bitumen volumes have more than doubled following the successful facility turnaround in the third quarter of 2009 when Nexen replaced valves in the water treatment system, cleaned out the hot lime softeners and isolated the water treatment trains.

Syncrude

Syncrude production increased 5% from 2009 to average 21,200 boe/d for the year. Production in 2010 was impacted by several factors including a scheduled turnaround of the LC finer and Coker 8-1 as well as unscheduled maintenance on both the sour water treatment and vacuum distillation units.

United States

Production in the Gulf of Mexico increased 5,100 boe/d from 2009, primarily as a result of a full year of production from Nexen's non-operated Longhorn development, which came on stream in late 2009. This was partially offset by natural field declines at Aspen and Gunnison. Nexen's shelf production decreased 7% from 2009 as a result of natural declines and limited capital investment in these mature fields.

The drilling moratorium in the Gulf of Mexico had no significant impact on Nexen's shelf and deep-water production during the year.

Yemen

Production in Yemen decreased 17% compared to 2009, consistent with Nexen's expectations as the field matures and development drilling is reduced. During 2010, Nexen drilled 13 development wells at Masila and six development wells at Block 51, as Nexen concentrated its drilling program on maximizing reserve recoveries and economic returns during the remaining term of the contract.

Other Countries

Production from Guando in Colombia decreased to average approximately 2,100 boe/d in 2010. This decline reflected natural field declines and the reduced working interest in the field effective in the second quarter of 2009. Under the terms of Nexen's licence, its working interest in the Guando field decreased from 20% to 10% in May 2009 after cumulative production from the field reached 60 million barrels.

Higher Realized Prices Increased Net Income by C$738 Million

Crude oil prices continued to strengthen in 2010 with both WTI and Dated Brent increasing 29% compared to 2009, averaging about US$79.50/bbl for the year. The impact of higher crude oil prices was partially reduced by the stronger Canadian dollar, while Nexen's realized crude oil price was 18% higher than 2009. NYMEX natural gas prices increased 6% from the prior year, while AECO stayed flat at C$3.92/mcf. Nexen's realized natural gas price increased 12% to average C$4.54/mcf, primarily due to the stronger prices in the UK.

The Canadian dollar continued to strengthen against the US dollar in 2010 and exited the year above parity. This foreign exchange impact reduced Nexen's net sales by approximately C$600 million, as Nexen's realized crude oil and gas prices were C$8.58/bbl and C$0.49/mcf lower, respectively. However, Nexen's US-dollar denominated debt, operating expenses and capital expenditures are lower when translated to Canadian dollars.

Higher Operation Expenses Decreased Net Income by C$385 Million

Operating costs increased C$385 million from 2009 primarily due to costs associated with's Long Lake project. Long Lake operating costs of C$373 million were expensed during 2010. At January 1, 2010, Nexen ceased capitalizing its Long Lake start-up costs. As Long Lake operating costs are mainly fixed, increasing volumes improved Nexen's per unit operating cost by about 10% from earlier in the year. Elsewhere, a full year of operating costs at Ettrick were offset by reduced maintenance and workover costs in Yemen and the sale of Nexen's Canadian heavy oil properties in the third quarter. These production changes increased Nexen's corporate average by C$4.03/boe.

In the UK North Sea, Buzzard increased Nexen's corporate average by C$0.20/boe due to a combination of higher maintenance activity and slightly lower production. Elsewhere in the UK, higher North Sea costs increased Nexen's corporate average by C$0.33/boe. At Scott, the per unit cost increased due to maintenance downtime and third-party outages in the second half of 2010.

In Yemen, lower maintenance and workover costs only partially offset the impact of production declines, which increased Nexen's corporate average cost by C$0.16/boe. At Syncrude, the impact of additional operating costs was partially offset by higher production volumes. These changes increased Nexen's corporate average by C$0.07/boe.

In Canada, the sale of Nexen's heavy oil properties in July reduced operating costs by C$52 million as compared to 2009. Nexen's heavy oil properties had higher per unit operating costs than its corporate average.

The stronger Canadian dollar reduced Nexen's corporate average by C$0.80/ boe as operating costs of Nexen's international and US assets are denominated in US dollars.

Lower Oil and Gas DD&A Increased Net Income by C$29 Million

Nexen's average DD&A expense decreased C$0.97/boe from 2009. The stronger Canadian dollar reduced Nexen's corporate average by C$1.61/boe as depletion of Nexen's international and US assets is denominated in US dollars. This was more than offset by changes in Nexen's production mix which increased its corporate average rate by C$2.05/boe. The change in mix was mainly driven by higher sales volumes at Ettrick, Longhorn and Long Lake, all of which have depletion rates higher than Nexen's corporate average.

Higher Exploration Expense Decreased Net Income by C$26 Million

Nexen's exploration expense increased 9% from 2009. Nexen's exploration program focuses on opportunities in the US Gulf of Mexico, the North Sea and offshore West Africa. Unsuccessful drilling costs were 44% lower than 2009 and represented 15% of Nexen's exploration drilling capital. In 2009, Nexen expensed 26% of its exploration drilling capital. Nexen expensed costs related to three unsuccessful wells in the North Sea and costs related to CBM properties in Canada in 2010. The Brand well and the Deacon well in the North Sea failed to encounter hydrocarbons and Nexen expensed drilling costs of C$25 million and C$14 million, respectively. In Canada, Nexen expensed C$17 million of drilling costs related to its CBM exploration activities in central Alberta, where Nexen has no future development plans.

Seismic expenditures increased 23% compared to 2009. Additional purchases in the Gulf of Mexico and the United Kingdom were partially offset by lower spending in Norway and Canada. Seismic data costs will fluctuate depending on the level of Nexen's evaluation stage. Other exploration costs include support costs, lease rental expenses and unutilized drilling rig costs.

Oil & Gas Netbacks

Netbacks are the cash margins Nexen receives for every equivalent barrel sold before general and administrative expenses and cash taxes in the UK. Nexen's netbacks improved 36% since 2006, while WTI and Brent are up 20% and 22%, respectively. Nexen's cash netbacks are 63% of realized sales prices in 2010. This is caused by transitioning Nexen's production to lower royalty jurisdictions and stronger commodity prices.

| | 2010 | 2009 | 2008 | 2007 | 2006 |
|---|---|---|---|---|---|
| Oil and Gas Realized Sales Price (C$/boe) | 70.11 | 60.02 | 89.78 | 68.46 | 62.92 |
| Cash Netback (C$/boe) | 44.38 | 38.55 | 60.64 | 43.22 | 32.75 |
| Cash Netback as % of Realized Sales Price | 63% | 64% | 68% | 63% | 52% |

The following table includes the sales prices, per-unit costs and netbacks for Nexen's producing assets, calculated using Nexen's working interest production before and after royalties.

Before Royalties1

| 2010 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| (C$/boe) | UK | Canada | Long Lake | Syncrude | US | Yemen | Other | Total |
| Sales | 76.51 | 34.33 | 77.07 | 81.23 | 47.35 | 81.86 | 76.83 | 70.11 |
| Royalties and Other | – | (5.29 ) | (3.65 ) | (6.27 ) | (3.55 ) | (36.65) | (5.37 ) | (8.16 ) |
| Operating Expenses | (8.24 ) | (12.31) | (100.09) | (36.74 ) | (10.02) | (10.25) | (6.99 ) | (15.67) |
| In-country Taxes2 | – | – | – | – | – | (10.80) | – | (1.90 ) |
| Cash Netback | 68.27 | 16.73 | (26.67 ) | 38.22 | 33.78 | 24.16 | 64.47 | 44.38 |

| 2009 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| (C$/boe) | UK | Canada | Long Lake | Syncrude | US | Yemen | Other | Total |
| Sales | 65.93 | 34.58 | – | 70.96 | 46.27 | 68.49 | 59.05 | 60.02 |
| Royalties and Other | – | (5.75 ) | – | (6.04 ) | (4.89 ) | (28.94) | (4.52 ) | (8.06 ) |
| Operating Expenses | (6.87 ) | (12.76) | – | (35.92 ) | (12.58) | (10.69) | (6.03 ) | (11.66) |
| In-country Taxes2 | – | – | – | – | – | (8.31 ) | – | (1.75 ) |
| Cash Netback | 59.06 | 16.07 | – | 29.00 | 28.80 | 20.55 | 48.50 | 38.55 |

| 2008 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| (C$/boe) | UK | Canada | Long Lake | Syncrude | US | Yemen | Other | Total |
| Sales | 94.45 | 58.34 | – | 105.47 | 79.02 | 99.87 | 98.98 | 89.78 |
| Royalties and Other | – | (12.25) | – | (15.11 ) | (11.03) | (46.94) | (7.88 ) | (15.06) |
| Operating Expenses | (6.75 ) | (13.12) | – | (36.53 ) | (11.57) | (8.51 ) | (4.52 ) | (11.04) |
| In-country Taxes2 | – | – | – | – | – | (13.31) | – | (3.04 ) |
| Cash Netback | 87.70 | 32.97 | – | 53.83 | 56.42 | 31.11 | 86.58 | 60.64 |

After Royalties1

| 2010 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| (C$/boe) | UK | Canada | Long Lake | Syncrude | US | Yemen | Other | Total |
| Sales | 76.51 | 34.33 | 77.07 | 81.23 | 47.35 | 81.86 | 76.83 | 70.11 |
| Operating Expenses | (8.24 ) | (14.10) | (105.17) | (39.78 ) | (10.76) | (18.69) | (7.52 ) | (17.62) |
| In-country Taxes2 | – | – | – | – | – | (19.69) | – | (2.15 ) |
| Cash Netback | 68.27 | 20.23 | (28.10 ) | 41.45 | 36.59 | 43.48 | 69.31 | 50.34 |

APPENDIX IIFINANCIAL INFORMATION OF NEXEN GROUP

| 2009 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| (C$/boe) | UK | Canada | Long Lake | Syncrude | US | Yemen | Other | Total |
| Sales | 65.93 | 34.58 | – | 70.96 | 46.27 | 68.49 | 59.05 | 60.02 |
| Operating Expenses | (6.87 ) | (14.80) | – | (39.09 ) | (14.10) | (18.34) | (6.53 ) | (13.33) |
| In-country Taxes2 | – | – | – | – | – | (14.26) | – | (2.00 ) |
| Cash Netback | 59.06 | 19.78 | – | 31.87 | 32.17 | 35.89 | 52.52 | 44.69 |

| 2008 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| (C$/boe) | UK | Canada | Long Lake | Syncrude | US | Yemen | Other | Total |
| Sales | 94.45 | 58.34 | – | 105.47 | 79.02 | 99.87 | 98.98 | 89.78 |
| Operating Expenses | (6.75 ) | (16.38) | – | (42.04 ) | (13.48) | (15.88) | (4.91 ) | (13.18) |
| In-country Taxes2 | – | – | – | – | – | (24.83) | – | (3.63 ) |
| Cash Netback | 87.70 | 41.96 | – | 63.43 | 65.54 | 59.16 | 94.07 | 72.97 |

1Before-royalty cash netbacks are calculated by dividing sales, royalties and other, operating expenses and in-country taxes by production before royalties. After-royalty cash netbacks are calculated by dividing sales, operating expenses and in-country taxes by production after royalties.

2Comprises income taxes payable in Yemen that are included in the government's share of profit oil.

Lower Contributions from Energy Marketing Reduced Net Income by C$322 Million

Energy marketing generated C$224 million of proceeds in 2010 from dispositions including the sale of Nexen's European gas and power business, Nexen's North America natural gas trading operations and Nexen's crude oil lease gathering, pipeline and storage assets in North Dakota and Montana, thereby substantially completing the re-alignment of Nexen's energy marketing business to focus on marketing proprietary crude oil production from North America, the North Sea and Yemen.

Results from energy marketing for the year are lower compared to 2009 when Nexen's marketing contribution was buoyed by the increased value of its natural gas inventories with rising gas prices in late 2009. Gains generated during the fourth quarter of 2010 from capturing crude oil contango (increasing future prices) were offset by widening heavy oil differentials in 2010.

Lower Chemicals Contribution Decreased Net Income by C$48 Million

North America chlorate revenue decreased 2% in 2010, as an 11% decrease in prices was partially offset by a 10% increase in sales volumes. North America chlor-alkali revenue remained flat as weaker caustic prices were offset by higher

volumes. In Brazil, sales revenues increased by 2% as strong chlorate revenues were partially offset by lower acid revenues. Chlorate revenues increased by 4% as a result of higher prices. This was partially offset by lower acid revenues of 10% as a result of lower prices and sales volumes.

The Canadian dollar continued to strengthen during the year and chemicals contribution includes foreign exchange gains of C$15 million on the Canexus US-dollar denominated debt. The 2009 results included unrealized foreign exchange gains of C$50 million related to Canexus US-dollar denominated debt.

Lower G&A Costs Increased Net Income by C$15 Million

G&A costs decreased 3% from 2009 primarily as the impact of a recovery of stock-based compensation during the year was substantially offset by higher G&A costs. Changes in Nexen's share price create volatility in its net income as Nexen accounts for stock-based compensation using the intrinsic-value method. This method uses Nexen's share price at the end of the reporting period to determine Nexen's stock-based compensation obligations and related expense. During the year, Nexen recovered non-cash stock-based compensation costs of C$41 million as its stock price ended the year at C$22.80/share, compared to the previous year when it closed at C$25.22/share. This recovery was partially offset by cash payments for stock-based compensation programs of C$27 million, 66% lower than 2009.

G&A expenses before stock-based compensation increased C$68 million primarily due to non-recurring costs associated with Nexen's non-core asset disposition programs.

Higher Net Interest Expense Reduced Net Income by C$12 Million

Net financing costs increased C$12 million from 2009 as higher interest costs of C$22 million were partially offset by additional capitalized interest of C$10 million. The higher expense was due to additional borrowing costs of C$52 million on Nexen's long-term debt and additional stand-by fees of C$8 million on its term credit facilities. These costs were reduced by the impact of a stronger Canadian dollar, which lowered Nexen's US-dollar denominated interest costs by C$41 million.

Capitalized interest was C$10 million higher than 2009. Increases in capitalized interest at Usan and on the fourth platform at Buzzard, were partially offset by lower capitalized interest on Ettrick, which was completed in 2009.

Higher Taxes Decreased Net Income by C$504 Million

Nexen's total provision for income taxes increased from 2009 as a result of net gains on its non-core asset disposition program and stronger commodity prices, which improved Nexen's operating results. Nexen's income tax provision includes current taxes in the United Kingdom, Yemen, Norway, Colombia and the United States.

Other

In 2010, Nexen realized net gains of C$740 million on the disposition of non-core assets, consisting of the following:

heavy oil properties in Canada for proceeds of C$939 million, net of closing adjustments, realizing a gain of C$781 million;

North American natural gas energy marketing operations for proceeds of C$9 million, recognizing a non-cash loss of C$259 million, which were primarily related to the transfer of long-term physical transportation commitments;

crude oil lease gathering, pipelines and storage assets in north Dakota and Montana for proceeds of C$201 million, realizing a gain of C$121 million;

lands in the Athabasca region of northern Alberta for which Nexen had no near-term development plans for proceeds of C$81 million, realizing a gain of C$80 million; and

undeveloped lease in the UK North Sea for proceeds and gains of C$17million.

In 2010, Nexen purchased put options on 100,000 bbls/d of Nexen's 2011 crude oil production. These options establish a monthly WTI floor price of between US$50/bbl and US$63/bbl and provide a base level of price protection without limiting Nexen's upside to higher prices. The options settle monthly and are recorded at fair value throughout their term. As a result, changes in forward crude oil prices created gains or losses on these options at each period end. The put options were purchased for C$33 million and are carried at fair value. At December 31, 2010, the fair value of the options was approximately C$9 million and Nexen recorded a fair value loss of C$24 million in the year.

In late 2009, Nexen purchased put options on 90,000 bbls/d of Nexen's 2010 crude oil production. These options established a WTI floor price of US$50/bbl on these volumes. Options on 60,000 bbls/d settled monthly, while the remaining options settled annually. The put options were purchased for C$39 million and were carried at fair value. At December 31, 2009, higher crude oil prices reduced the fair value of the options to C$17 million, and Nexen recorded a fair value loss in 2009 of C$22 million. At December 31, 2010, higher forward crude oil prices reduced the fair value of the options to nil and Nexen expensed the remaining fair value of C$17 million in 2010.

## 3. Liquidity and Capital Resources

Capital Structure

| (C$ millions) | December 31, 2010 | December 31, 2009 |
|---|---|---|
| Net Debt1 | | |
| Bank Debt | – | 1,803 |
| Public Senior Notes | 4,636 | 4,982 |
| Total Senior Debt | 4,636 | 6,785 |
| Subordinated Debt | 443 | 466 |
| Total Debt | 5,079 | 7,251 |
| Less: Cash and Cash Equivalents | (1,005) | (1,700) |
| Total Net Debt2 | 4,074 | 5,551 |
| Nexen Inc. Shareholders' Equity3 | 8,707 | 7,582 |

1 Includes all of Nexen's debt and is calculated as long-term debt and short-term borrowings less cash and cash equivalents.

2 December 31, 2010 excludes Net Debt related to Nexen's chemical operations that is included in assets and liabilities held for sale (see Note 20 of Nexen's 2010 Consolidated Financial Statements). Nexen's remaining interest was sold in February 2011 for C$458 million.

3 Equity is the historical issue price of equity and accumulated retained earnings.

Net Debt

Nexen ended the year with net debt of approximately C$4,074 million, C$1,477 million lower than 2009. The year-over-year change in Nexen's net debt results from:

| (C$ millions) | 2010 | 2009 |
|---|---|---|
| Capital Investment | 2,523 | 2,742 |
| Proved Property Acquisitions | 79 | 755 |
| Net Proceeds from Non-core Asset Dispositions | (1,262) | (17) |
| Cash Flow from Operating Activities | (2,349) | (1,886) |
| Deficiency (Surplus) | (1,009) | 1,594 |
| Dividends on Common Shares | 104 | 104 |
| Issue of Common Shares | (55) | (57) |
| Reclassification of Canexus Net Debt Related to Sale | (391) | – |
| Other | 77 | 232 |
| Foreign Exchange Translation of US-dollar Debt and Cash | (203) | (897) |
| Increase (Decrease) in Net Debt | (1,477) | 976 |

Nexen's net debt decreased 27% from 2009 primarily as a result of its non-core asset disposition program. Nexen's 2010 disposition program included the sale of its heavy oil assets in Canada and the sale of various non-core energy marketing operations. Total proceeds from Nexen's disposition program in 2010 was approximately C$1.3 billion. Net debt related to Canexus of C$391 million has been included in liabilities held for sale at December 31, 2010.

In 2010, Nexen's capital investment and property acquisition costs were approximately C$900 million lower than 2009, when Nexen acquired its additional 15% interest in Long Lake. Cash flow from operating activities increased from 2009 as a result of higher production and stronger commodity prices. Nexen's oil and gas investment exceeded its operating cash flows by about C$250 million in 2010, largely due to the acquisition of acreage in the Horn River shale gas play. The stronger Canadian dollar relative to the US dollar reduced Nexen's US-dollar-denominated debt. As December 31, 2010, Nexen had liquidity of approximately C$4 billion, which was comprised of cash and undrawn committed credit facilities, most of which are available until July 2014.

Change in Working Capital

| (C$ millions) | December 31 2010 | December 31 2009 | Increase (Decrease) |
|---|---|---|---|
| Cash and Cash Equivalents | 1,005 | 1,700 | (695) |
| Restricted Cash | 40 | 198 | (158) |
| Accounts Receivable | 1,938 | 2,788 | (850) |
| Inventories and Supplies | 549 | 680 | (131) |
| Accounts Payable and Accrued Liabilities | (2,545) | (3,038) | 493 |
| Other | 33 | 70 | (37) |
| Total | 1,020 | 2,398 | (1,378) |

Nexen's working capital balances decreased significantly from 2009. Cash and cash equivalents decreased C$695 million as Nexen uses proceeds from the disposition program and cash on hand to fund its capital investment shortfall and repay its term credit facilities during the year. Accounts receivable, inventory and accounts payable reduced as a result of changes in its energy marketing group and the disposition of its heavy oil properties in Canada. The sale of Nexen's North American natural gas operations included the transfer of inventory, accounts receivable and payable balances to the purchaser. This, combined with reduced trading activity as Nexen focuses on supporting its core physical business as a producer/marketer, reduced its energy marketing working capital requirements from 2009.

Nexen's working capital balances at December 31, 2010 exclude accounts receivable, inventories and accounts payable related to its chemicals operations as these balances are included in assets and liabilities held for sale.

At December 31, 2010, Nexen's restricted cash consists of margin deposits of C$40 million (2009-C$198 million) related to exchange-traded derivative financial contracts used by its energy marketing group to economically hedge physical commodities, storage, transportation and customer sales contracts. Nexen is required to maintain margin for net out-of-the-money derivative financial contracts.

The weaker US dollar at the end of the year impacted Nexen's US-dollar denominated working capital by decreasing accounts receivable, inventories and accounts payable by approximately C$123 million, C$19 million and C$123 million, respectively.

Liquidity

At December 31, 2010, Nexen had term credit facilities of C$3 billion that were available until July 2014, of which C$322 million was utilized to support letters of credit. Nexen also had C$464 million of uncommitted, unsecured credit facilities, of which C$112 million was supporting letters of credit outstanding at December 31, 2010.

The following table shows how Nexen financed its business activities over the last five years. When Nexen's operating cash flows exceed its investment requirements, Nexen generally pays down debt or return cash to shareholders. Nexen borrows or issues equity to fund investment requirements that exceed its operating cash flow.

| (C$ millions) | 2010 | 2009 | 2008 | 2007 | 2006 |
|---|---|---|---|---|---|
| Cash Flow from Operating Activities | 2,349 | 1,886 | 4,354 | 2,830 | 2,374 |
| Cash Flow from Investing Activities | (1,422) | (3,743) | (3,189) | (3,281) | (3,388) |
| Surplus (Deficiency) | 927 | (1,857) | 1,165 | (451) | (1,014) |
| Cash Flow from Financing Activities | (1,506) | 1,821 | 322 | 677 | 1,081 |
| Net Cash Generated (Used) | (579) | (36) | 1,487 | 226 | 67 |

In 2009, Nexen's capital investment, including the acquisition of an additional working interest in Long Lake, exceeded its cash flow from operating activities. The purchase of Long Lake was funded primarily from accumulating excess cash in 2008. In response to improving credit markets, Nexen also issued US$1 billion of senior notes during the year, with US$300 million maturing in 2019 and US$700 million maturing in 2039. Proceeds from the debt issue were used to repay a portion of Nexen's outstanding term credit facilities as well as for general corporate purposes.

In 2010, Nexen repaid C$1.5 billion of term credit facilities using proceeds from its non-core asset disposition program. Repaying Nexen's outstanding term credit facilities increased the average term-to-maturity of Nexen's debt to 21 years.

Contractual Obligations, Commitments and Guarantees

Nexen assumes various contractual obligations and commitments in the normal course of its operations and financing activities. They include:

| (C$ millions) | Payments Total | < 1 year | 1-3 years | 4-5 years | > 5 years |
|---|---|---|---|---|---|
| Long-Term Debt | 5,171 | – | 497 | 249 | 4,425 |
| Cumulative Interest on Long-Term Debt | 7,286 | 336 | 670 | 612 | 5,668 |
| Operating Leases1 | 423 | 98 | 163 | 84 | 78 |
| Capital Leases | 86 | 4 | 8 | 8 | 66 |
| Energy Commodity Contracts | 283 | 168 | 105 | 5 | 5 |
| Transportation and Storage Commitments1 | 435 | 134 | 196 | 75 | 30 |
| Work Commitments and Purchase Obligations2 | 1,735 | 961 | 654 | 75 | 45 |
| Asset Retirement Obligations | 2,552 | 55 | 84 | 145 | 2,268 |
| Total | 17,971 | 1,756 | 2,377 | 1,253 | 12,585 |

1Payments for operating leases and transportation and storage commitments are deducted from Nexen's cash flow from operating activities.

2Some of these payments relate to work commitments that Nexen can cancel without penalties or additional fees.

4. Non-GAAP Measures

Cash Flow from Operations

| (C$ millions) | 2010 | 2009 | 2008 |
|---|---|---|---|
| Cash Flow from Operating Activities | 2,349 | 1,886 | 4,354 |
| Changes in Non-Cash Working Capital | (338) | 25 | (119) |
| Other | 159 | 318 | 18 |
| Impact of Annual Crude Oil Put Options | (40) | (14) | (24) |
| Cash Flow from Operations | 2,130 | 2,215 | 4,229 |

Net Debt

| (C$ millions) | 2010 | 2009 | 2008 |
|---|---|---|---|
| Bank Debt | – | 1,803 | 1,448 |
| Public Senior Notes | 4,636 | 4,982 | 4,582 |
| Total Senior Debt | 4,636 | 6,785 | 6,030 |
| Subordinated Debt | 443 | 466 | 548 |
| Total Debt | 5,079 | 7,251 | 6,578 |
| Less: Cash and Cash Equivalents | (1,005) | (1,700) | (2,003) |
| Total Net Debt | 4,074 | 5,551 | 4,575 |

## II. CHARGE ON ASSETS

None of Nexen's property or assets has been pledged as security for borrowed money. There are no other liens or encumbrances on Nexen's property or assets other than those that are customary in the oil and gas industry. As at June 30, 2012, Nexen had restricted cash of C$102 million (December 31, 2011 – C$45 million; December 31, 2010 – C$40 million and December 31, 2009 – C$198 million), which consisted of margin deposits relating to exchange-traded derivative contracts.

## III. GEARING RATIO

The gearing ratio of Nexen is set out below.

| (C$ million) | 30 June 2012 | 31 December 2011 | 31 December 2010 | 31 December 2009 |
|---|---|---|---|---|
| Long-term Debt | 4,391 | 4,383 | 5,090 | 7,259 |
| Less: Cash and Cash Equivalents | (1,255) | (845) | (1,005) | (1,700) |
| Total Net Debt1 | 3,136 | 3,538 | 4,085 | 5,559 |
| Shareholder's Equity | 8,839 | 8,373 | 7,814 | 6,787 |
| Gearing Ratio2 | 35% | 42% | 52% | 82% |

1 Net debt is a non-GAAP measure.
2 Gearing ratio is a non-GAAP measure.

## IV. MARKET RISKS

Nexen is exposed to normal market risks inherent in the oil and gas business, including commodity price risk, foreign currency rate risk, interest rate risk and credit risk. Nexen recognizes these risks and manage its operations to minimize its exposures to the extent practical.

Commodity Price Risk

Commodity price risk related to crude oil prices is Nexen's most significant market risk exposure. Crude oil and natural gas prices are sensitive to numerous worldwide factors, many of which are beyond Nexen's control, and are generally sold at contract or posted prices. Changes in crude oil and natural gas prices may significantly affect Nexen's results of operations and cash generated from operating activities. Consequently, these changes may also affect the value of Nexen's oil, gas properties, Nexen's level of spending for exploration and development, and its ability to meet its obligations as they become due.

Nexen's realized crude oil prices are based on various reference prices, primarily WTI and Brent and other prices that generally track the movement of WTI and Brent. Actual prices realized differ from the reference prices to reflect quality differentials and transportation. WTI, Brent and other international reference prices are affected by numerous and complex worldwide factors such as supply and demand fundamentals, economic outlooks, production quotas set by the Organization of Petroleum Exporting Countries and political events. Quality differentials are affected by local supply and demand factors.

Nexen is also exposed to natural gas price movements. Natural gas prices are generally influenced by regional supply and demand fundamentals and, to a lesser extent, local market conditions and oil prices.

The majority of Nexen's oil and gas production is sold under short-term contracts, exposing Nexen to the risk of price movements. Other energy contracts Nexen enters into also expose it to commodity price risk between the time it purchases and sells contracted volumes. Nexen actively manages these risks by using derivative contracts such as commodity put options.

Nexen's energy marketing group's primary focus is to market proprietary crude oil and natural gas production. Nexen also buys and sells third-party production. In order to manage the commodity and foreign exchange price risks that come from this activity, Nexen uses financial derivative contracts, including energy-related futures, forwards, swaps and options, as well as currency swaps or forwards.

Nexen's risk management activities make use of tools such as Value-at-Risk ("VaR") and stress testing. VaR is a statistical estimate of the expected profit or loss of a portfolio of positions assuming normal market conditions. Nexen uses a 95% confidence interval and an assumed five-day holding period in its measure, although actual results can differ from this estimate in abnormal market conditions, or if positions are held longer than five days based on market views or a lack of market liquidity to exit them. Nexen estimates VaR primarily by using the Variance-Covariance method based on historical commodity price volatility and correlation inputs where available, and by historical simulation in other situations. Nexen's estimate is based upon the following key assumptions:

- changes in commodity prices are either normally or "T" distributed;

price volatility is comparable to prior periods; and

price correlation relationships remain stable.

Nexen has defined VaR limits for different segments of its energy marketing business. These limits are calculated on an economic basis and include physical and financial derivatives, as well as physical transportation and storage capacity contracts accounted for as executory contracts in Nexen's financial statements. Nexen monitors its positions against these VaR limits daily.

If a significant market shock occurred, the key assumptions underlying Nexen's VaR estimate could be exceeded and the potential loss could be greater than its estimate. Nexen performs stress tests on a regular basis to complement VaR and assess the impact of abnormal changes in prices on its positions.

Foreign Currency Risk

Foreign currency risk is created by fluctuations in the fair values or cash flows of financial instruments due to changes in foreign exchange rates. A substantial portion of Nexen's activities are transacted in or referenced to US dollars including:

sales of crude oil and natural gas products;

capital spending and expenses in Nexen's oil and gas activities;

commodity derivative contracts used primarily by Nexen's energy marketing group; and

short-term borrowings and long-term debt.

Nexen manages its exposure to fluctuations between the US and Canadian dollar by matching its expected net cash flows and borrowings in the same currency. Cash flows generated by Nexen's foreign operations and borrowings on Nexen's US-dollar debt facilities are generally used to fund US-dollar capital expenditures and debt repayments. Nexen maintains revolving Canadian and US-dollar borrowing facilities that can be drawn upon or repaid depending on expected net cash flows. Nexen designates most of its US-dollar borrowings as a hedge against its US-dollar net investment in its foreign operations.

Nexen does not have any material exposure to highly inflationary foreign currencies.

Interest Rate Risk

Nexen is exposed to changes in interest payments on any floating-rate debt as interest rates fluctuate. Nexen's only floating-rate debt is its term credit facilities which are expected to be used minimally and, therefore, Nexen expects its sensitivity to changes in interest rates in 2012 to be immaterial.

Credit Risk

Credit risk affects Nexen's oil and gas operations and its energy marketing activities, and is the risk of loss if counterparties do not fulfill their contractual obligations. Most of Nexen's credit exposures are with counterparties in the energy industry, including integrated oil companies and refiners, and are subject to normal industry credit risk. Over 75% of Nexen's exposure is with these large energy companies. This concentration of risk within the energy industry is reduced because of Nexen's broad base of domestic and international counterparties. Nexen takes the following measures to reduce this risk:

assess the financial strength of Nexen's counterparties through a credit analysis process;

limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;

routinely monitor credit risk exposures, including sector, geographic and corporate concentrations of credit, and report these to management and the board of directors;

set and regularly review counterparty credit limits based on rating agency credit ratings and internal assessments of company and industry analysis; and

use standard agreements where possible that allow for the netting of exposures associated with a single counterparty.

Nexen believes these measures minimize its overall credit risk; however, there can be no assurance that these processes will protect Nexen against all losses from non-performance.

V. EMPLOYEES

Nexen had 2,938, 3,067, 3,925 and 4,594 employees on 30 June 2012, 31 December 2011, 31 December 2010 and 31 December 2009, respectively. Nexen's remuneration programs for employees consist of a combination of salary, annual cash incentives and long-term incentives (stock-based compensation). Nexen uses third-party compensation surveys to compare its pay levels and practices to its peers. Annual cash incentives are calculated as a percentage of salary based on targets. The amount the employee actually receives may be higher or lower than the target, and depends on both company and individual performance.

Nexen has adopted stock-based compensation programs which consist of tandem option (TOPs), stock appreciation right (STARs), restricted share unit (RSUs) and deferred share unit (DSUs) plans. TOPs to purchase Common Shares are granted to officers and employees at the discretion of Nexen Board. Each TOP gives the holder a right to either purchase one Common Share at the exercise price or to receive a cash payment equal to the excess of the market price of the Common Share over the exercise price. Under the STARs plan, employees are entitled to cash payments equal to the excess of market price of the Common Share over the exercise price of the right. Under the RSU plan, employees are entitled to receive a cash payment equal to the average closing market price of one Common Share for the 20 days prior to the vesting date for each RSU granted. Certain TOPs, STARs and RSUs granted contain a performance vesting condition. DSUs are equity-based awards granted to directors of Nexen. The units accumulate over a director's term of service and vest when the director leaves the board.

Nexen has also adopted defined benefit and defined contribution pension plans, as well as other post-retirement benefit programs, which cover substantially all employees. For the defined benefit plans, Nexen provides retirement benefits to employees based on their length of service and final average earnings. The defined contribution pension plan benefits are based on plan contributions. Other post-retirement benefits include group life and supplemental health insurance for eligible employees and their dependents.

## VI. OUTLOOK FOR REMAINDER OF 2012

The date of this discussion is October 24, 2012.

| | Average Daily Annual Production before Royalties | | | | |
|---|---|---|---|---|---|
| Crude Oil, NGLs and Natural Gas (mboe/d) | Q1 2012 Actual | Q2 2012 Actual | Q3 2012 Actual | Q4 2012 (estimate) | FY 2012 (estimate) |
| UK – Buzzard | 82 | 84 | 60 | 50-60 | 70-85 |
| UK – Other | 29 | 30 | 26 | 25-32 | 24-32 |
| Oil Sands – Long Lake Bitumen | 22 | 22 | 14 | 22-28 | 19-25 |
| Canada – Oil & Gas | 22 | 20 | 18 | 15-20 | 15-19 |
| Oil Sands – Syncrude | 21 | 17 | 23 | 22-24 | 21-23 |
| United States | 16 | 14 | 14 | 15-17 | 15-19 |
| Nigeria | 3 | 20 | 20 | 22-30 | 14-28 |
| Other Countries | 7 | 6 | 6 | 2 | 2 |
| Total | 202 | 213 | 181 | ~180-200 | ~185-220 |

Nexen expects to be on-track to meet annual production guidance of 185,000 – 220,000 boe/d. Buzzard, Usan and Long Lake continue to be the critical drivers of the guidance range.

Nexen adjusted its fourth quarter guidance to 180,000 – 220,000 boe/d to reflect the timing and the length of the turnaround at Buzzard, as well as updated expectations of production at Usan. Nexen's expectations for annual production guidance at Buzzard and Usan remain unchanged.

Nexen expects net debt to increase in the fourth quarter as capital investment is expected to exceed cash flow from operations, depending on oil prices.

## A.UNAUDITED PRO FORMA FINANCIAL INFORMATION OF THE ENLARGED GROUP

### INTRODUCTION

The following is an illustrative and unaudited pro forma consolidated statement of assets and liabilities as at 30 June 2012 (“Unaudited Pro Forma Financial Information”) of CNOOC Limited (the “Company”) and its subsidiaries (the “Group”) and Nexen Inc. (“Nexen”) and its subsidiaries (the “Nexen Group”) (hereinafter collectively referred to as the “Enlarged Group”), which has been prepared on the basis of the notes set out below for the purpose of illustrating the effect of the Proposed Acquisition, as if it had taken place on 30 June 2012. The Unaudited Pro Forma Financial Information has been prepared by the directors of the Company in accordance with paragraph 4.29 of The Rules Governing the Listing of Securities on The Stock Exchange of Hong Kong Limited (“Listing Rules”), on the basis which is consistent with the accounting policies and presentation format of the Group.

The Unaudited Pro Forma Financial Information has been prepared for illustrative purposes only and is based on a number of assumptions, estimates, uncertainties and currently available information. Because of its hypothetical nature, it may not give a true picture of the financial position of the Enlarged Group had the Proposed Acquisition been completed as at 30 June 2012 or at any future dates.

The Unaudited Pro Forma Financial Information has been prepared based on the unaudited interim condensed consolidated statement of financial position of the Group as at 30 June 2012 as set out in Appendix I to this circular and the unaudited interim condensed consolidated statement of financial position of Nexen Group as at 30 June 2012 as set out in Appendix II to this circular after giving effect to the unaudited pro forma adjustments as described in the accompanying notes. A narrative description of the pro forma adjustments of the Proposed Acquisition that are (i) directly attributable to the transaction; and (ii) factually supportable, is summarised in the accompanying notes.

The Unaudited Pro Forma Financial Information should be read in conjunction with the unaudited financial information of the Group as set out in Appendix I and the unaudited financial information of Nexen Group as set out in Appendix II to this circular and other financial information included elsewhere in this circular.

APPENDIX III UNAUDITED PRO FORMA FINANCIAL INFORMATION OF THE ENLARGED GROUP

UNAUDITED PRO FORMA CONSOLIDATED STATEMENT OF THE ASSETS AND LIABILITIES OF THE ENLARGED GROUP

| RMB million | Unaudited consolidated statement of assets and liabilities of the Group as of 30 June 2012 Note 1 | Unaudited consolidated statement of assets and liabilities of the Nexen Group as of 30 June 2012 Note 2 | Unaudited pro forma adjustments Adjustment Note 3(a)-(e) | Adjustment Note 3(f) | Adjustment Note 4 | Adjustment Note 5 | Unaudited pro forma consolidated statement of assets and liabilities of the Enlarged Group as of 30 June 2012 |
|---|---|---|---|---|---|---|---|
| NON-CURRENT ASSETS | | | | | | | |
| Property, plant and equipment | 236,764 | 98,140 | 59,710 | | | | 394,614 |
| Intangible assets | 949 | – | | | | | 949 |
| Goodwill | – | 1,788 | 7,904 | | | | 9,692 |
| Investments in associates | 2,886 | – | | | | | 2,886 |
| Investment in a joint venture | 19,045 | – | | | | | 19,045 |
| Available-for-sale financial assets | 6,407 | – | | | | | 6,407 |
| Deferred tax assets | 57 | 2,706 | | | | | 2,763 |
| Derivative contracts | – | 31 | | | | | 31 |
| Other non-current assets | 420 | 686 | | | | | 1,106 |
| Total non-current assets | 266,528 | 103,351 | | | | | 437,493 |
| | | | | | | | |
| CURRENT ASSETS | | | | | | | |
| Inventories and supplies | 5,189 | 1,733 | | | | | 6,922 |
| Trade receivables | 18,241 | 10,316 | | | | | 28,557 |
| Derivative contracts | – | 949 | | | | | 949 |
| Held-to-maturity financial assets | 1,544 | – | | | | | 1,544 |
| | 63,317 | – | | | | (37,691) | 25,626 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Available-for-sale financial assets | | | | | | |
| Other current assets | 8,816 | 839 | | | | 9,655 |
| Time deposits with maturity over three months | 36,785 | 624 | | | (17,809) | 19,600 |
| Cash and cash equivalents | 13,801 | 7,683 | (94,845) | (474) | 93,449 | 19,614 |
| | | | | | | |
| Total current assets | 147,693 | 22,144 | | | | 112,467 |
| | | | | | | |
| TOTAL ASSETS | 414,221 | 125,495 | | | | 549,960 |

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APPENDIX III UNAUDITED PRO FORMA FINANCIAL INFORMATION OF THE ENLARGED GROUP

| | | | Unaudited pro forma adjustments | | | | |
|---|---|---|---|---|---|---|---|
| | Unaudited consolidated statement of assets and liabilities of the Group as of 30 June 2012 | Unaudited consolidated statement of assets and liabilities of the Nexen Group as of 30 June 2012 | Adjustment | Adjustment | Adjustment | Adjustment | Unaudited pro forma consolidated statement of assets and liabilities of the Enlarged Group as of 30 June 2012 |
| RMB million | Note 1 | Note 2 | Note 3(a)-(e) | Note 3(f) | Note 4 | Note 5 | |
| CURRENT LIABILITIES | | | | | | | |
| Loans and borrowings | 25,643 | – | | | | 37,949 | 63,592 |
| Derivative contracts | – | 643 | | | | | 643 |
| Trade and accrued payables | 19,589 | 13,989 | | | | | 33,578 |
| Other payables and accrued liabilities | 12,288 | – | 1,624 | (1,624) | | | 12,288 |
| Taxes payable | 7,372 | 5,198 | | | | | 12,570 |
| Total current liabilities | 64,892 | 19,830 | | | | | 122,671 |
| NON-CURRENT LIABILITIES | | | | | | | |
| Loans and borrowings | 29,347 | 26,883 | 3,242 | | | | 59,472 |
| Provision for dismantlement | 26,351 | 12,367 | | | | | 38,718 |
| Deferred tax liabilities | 5,902 | 9,557 | 23,642 | | | | 39,101 |
| Derivative contracts | – | 31 | | | | | 31 |
| Other non-current liabilities | 3,504 | 2,712 | | | | | 6,216 |
| Total non-current liabilities | 65,104 | 51,550 | | | | | 143,538 |
| TOTAL LIABILITIES | 129,996 | 71,380 | | | | | 266,209 |

Notes:

1.

The amounts are extracted from the unaudited interim condensed consolidated statement of financial position of the Group as at 30 June 2012 included in the published interim report of the Group for the six months ended 30 June 2012.

2. The amounts are extracted from the unaudited interim condensed consolidated statement of financial position of the Nexen Group as at 30 June 2012 as set out in Appendix II to this circular. The functional currency and the presentation currency of the Nexen Group are Canadian dollars. For illustrative purpose, the assets and liabilities of the Nexen Group as at 30 June 2012 are translated into RMB, the presentation currency of the Group, at the exchange rate of C$1.00 to RMB 6.1223 prevailing as at 30 June 2012.

3. The adjustments reflect the allocation of the cost of the Proposed Acquisition to the identifiable assets acquired and liabilities assumed by the Company. Upon completion of the Proposed Acquisition, the identifiable assets and liabilities of the Nexen Group will be accounted for in the consolidated financial statements of the Enlarged Group at fair value under the purchase method of accounting in accordance with IFRS/HKFRS 3 (Revised) “Business Combinations” (“IFRS/HKFRS 3”).

For the purpose of this Unaudited Pro Forma Financial Information, the directors of the Company have estimated the fair value of the identifiable assets and liabilities of the Nexen Group based on the assumption that the Proposed Acquisition was completed on 30 June 2012. The details of the fair value adjustments are as follows:

(a) the recognition of the fair value adjustment on property, plant and equipment of RMB59,710 million, which represents fair value uplifts of RMB51,083 million on Nexen’s proved oil and gas properties and of RMB8,627 million on Nexen’s unproved oil and gas properties. The total fair value attributed to these proved and unproved oil and gas properties is assessed by management.

(b)the increase of RMB1,624 million in other payables and accrued liabilities is for cash settlement of incentive plans awarded to management and employees, including tandem options, stock appreciation rights and share unit plans, and is payable before completion of the Proposed Acquisition.

(c)the increase of RMB3,242 million in non-current loans and borrowings represents excess of fair value over its book value which is carried at amortised cost using the effective interest method.

(d)deferred tax liabilities of RMB23,642 million are also recognised in the Unaudited Pro Forma Financial Information of the Enlarged Group as at 30 June 2012 as a result of the aforesaid fair value adjustments on property, plant and equipment, current and non-current liabilities.

(e)The increase of RMB7,904 million in goodwill represents the difference between the goodwill arising from the Proposed Acquisition (RMB9,692 million) and the carrying amount of goodwill on Nexen's books as of 30 June 2012 (RMB1,788 million).

For the purpose of preparation of the Unaudited Pro Forma Financial Information and for illustrative purpose, the recognition of goodwill arising from the Proposed Acquisition is analyzed as follows:

| | RMB million |
|---|---|
| Consideration (f) | 93,221 |
| Less: Carrying amount of the net assets acquired less goodwill currently carried in Nexen's books | (52,327 ) |
| Fair value adjustments | (54,844 ) |
| Add: Deferred tax liabilities recognized as a result of the fair value adjustments | 23,642 |
| | |
| Goodwill | 9,692 |

(f) The adjustments reflect cash settlement of employee incentive plans of RMB1,624 million (note c) and payment of consideration of RMB93,221 million (note e).

The fair value of the consideration (RMB93,221 million) is calculated based on the assumptions that 1) the Company will acquire 529,335,905 common shares of Nexen (which account for 100% of the issued and outstanding common shares of Nexen as of 30 June 2012) at US$27.50 for each consenting common share and for dissenting common shares, at its fair value as of the date before the shareholder resolution on approval of the Proposed Acquisition; 2) the Company will acquire 8,000,000 preferred shares of Nexen (which account for 100% of the issued and outstanding preferred shares of Nexen as of 30 June 2012) at C$26.00 for each consenting preferred share and for dissenting preferred shares, at its fair value as of the date before the shareholder resolution on approval of the Proposed Acquisition. The consideration is translated into RMB at the exchange rates of US$1.00 to RMB6.3249 and C$1.00 to RMB6.1223 prevailing as at 30 June 2012;

Since the consideration and the fair values of the identifiable assets and liabilities of the Nexen Group on the date of completion of the Proposed Acquisition may be substantially different from their respective values used in the Unaudited Pro Forma Financial Information, the final amount of the goodwill arising from the completion of the Proposed Acquisition may be different from the amount presented above.

4. The adjustment represents the payment of RMB474 million for legal and professional fees related to the Proposed Acquisition. The expenses are charged to income statement directly.

5. The Unaudited Pro Forma Financial Information has been prepared based on the assumption that the Company will obtain and utilise external banking facility of US$6 billion (or approximately RMB37,949 million) and receive gross cash proceeds of approximately RMB37,691 million from corporate wealth management products and RMB17,809 million from time deposits with maturity over three months, which will be mature on or before the completion of the Proposed Acquisition, to satisfy the cash consideration for the Proposed Acquisition.

6. The Unaudited Pro Forma Financial Information has been prepared based on the assumption that the transaction will proceed with Nexen providing substantive evidence that all regulatory approvals are officially obtained and valid.

7. The Unaudited Pro Forma Financial Information has been prepared based on the assumption that the Nexen Group will maintain its current group structure and no change is made for operational and tax planning purpose.

8. Save as aforesaid, no adjustment has been made to reflect any trading result or other transaction of the Enlarged Group entered into subsequent to 30 June 2012. In particular, the Unaudited Pro Forma Financial Information has not taken into account the sale of a 40% interest in Nexen's northeast British Columbia shale gas assets to a consortium led by INPEX CORPORATION of Japan.

## B.LETTER ON UNAUDITED PRO FORMA FINANCIAL INFORMATION OF THE ENLARGED GROUP

The following is the text of a report dated 20 December 2012, received from Ernst & Young, Certified Public Accountants, Hong Kong, for the purpose of incorporation in this circular.

22nd Floor, CITIC Tower
1 Tim Mei Avenue, Central
Hong Kong

20 December 2012

The Directors
CNOOC Limited

Dear Sirs,

We report on the unaudited pro forma consolidated statement of assets and liabilities of CNOOC Limited (the "Company") and its subsidiaries (collectively, the "Group"), Nexen Inc. ("Nexen") and its subsidiaries (collectively, the "Nexen Group") (the Group and the Nexen Group combined are collectively referred to as the "Enlarged Group") (the "Unaudited Pro Forma Financial Information") set out on pages III-1 to III-5 under the heading of "Unaudited Pro Forma Financial Information of The Enlarged Group" in Appendix III of the circular dated 20 December 2012 (the "Circular"), in connection with the proposed acquisition of 100% of the issued and outstanding common shares and preferred shares of Nexen (the "Proposed Acquisition") by the Company. The Unaudited Pro Forma Financial Information has been prepared by the directors of the Company (the "Directors"), for illustrative purposes only, to provide information about how the Proposed Acquisition might have affected the financial information presented. The basis of preparation of the Unaudited Pro Forma Financial Information is set out on pages III-1 to III-5 in Appendix III of the Circular.

Respective Responsibilities of the Directors and Reporting Accountants

It is the responsibility solely of the Directors to prepare the Unaudited Pro Forma Financial Information in accordance with paragraph 4.29 of the Rules Governing the Listing of Securities on The Stock Exchange of Hong Kong Limited (the "Listing Rules") and with reference to Accounting Guideline 7 "Preparation of Pro Forma Financial Information for Inclusion in Investment Circulars" issued by the Hong Kong Institute of Certified Public Accountants (the "HKICPA").

It is our responsibility to form an opinion, as required by paragraph 4.29(7) of the Listing Rules, on the Unaudited Pro Forma Financial Information and to report our opinion to you. We do not accept any responsibility for any reports previously given by us on any financial information used in the compilation of the Unaudited Pro Forma Financial Information beyond that owed to those to whom those reports were addressed by us at the dates of their issue.

Basis of Opinion

We conducted our engagement in accordance with Hong Kong Standard on Investment Circular Reporting Engagements 300 “Accountants’ Reports on Pro Forma Financial Information in Investment Circulars” issued by the HKICPA. Our work consisted primarily of comparing the unadjusted financial information with the source documents, considering the evidence supporting the adjustments, and discussing the Unaudited Pro Forma Financial Information with the Directors. This engagement did not involve independent examination of any of the underlying financial information.

Our work did not constitute an audit or a review made in accordance with Hong Kong Standards on Auditing, Hong Kong Standards on Review Engagements or Hong Kong Standards on Assurance Engagements issued by the HKICPA, and accordingly, we do not express any such audit or review assurance on the Unaudited Pro Forma Financial Information.

We planned and performed our work so as to obtain the information and explanations we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the Unaudited Pro Forma Financial Information has been properly compiled by the Directors on the basis stated, that such basis is consistent with the accounting policies of the Group and that the adjustments are appropriate for the purposes of the Unaudited Pro Forma Financial Information as disclosed pursuant to paragraph 4.29(1) of the Listing Rules.

Our work has not been carried out in accordance with the auditing standards or other standards and practices generally accepted in the United States of America or auditing standards of the Public Company Accounting Oversight Board (United States) and accordingly should not be relied upon as if it had been carried out in accordance with those standards.

The Unaudited Pro Forma Financial Information is for illustrative purposes only, based on the judgements and assumptions of the Directors, and, because of its hypothetical nature, does not provide any assurance or indication that any event will take place in the future and may not be indicative of the financial position of the Group as at 30 June 2012 or any future dates.

Opinion

In our opinion:

a. the Unaudited Pro Forma Financial Information has been properly compiled by the Directors on the basis stated;

b. such basis is consistent with the accounting policies of the Group; and

c. the adjustments are appropriate for the purposes of the Unaudited Pro Forma Financial Information as disclosed pursuant to paragraph 4.29(1) of the Listing Rules.

Yours faithfully,
Ernst & Young
Certified Public Accountants
Hong Kong

# APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

Executive Summary

In accordance with NI51-101, as at December 31, 2011, Nexen's proved plus probable reserves estimates were approximately 2.0 billion boe, of which 922 million boe are proved and 1,095 million boe are probable. Over 60% of these reserves relate to Canadian oil sands properties while the remainder is widely distributed throughout the world. Approximately half of Nexen's proved reserves are undeveloped of which 80% relate to Canadian oil sands developments.

The basis of the reserves estimates, the quantities by country and product type, their net present value of future net revenue, and other information such as land acreage and exploration and production activities are contained in the section titled "Reserves, Production And Related Information" on pages 20-40 of the 2011 AIF.

# APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

## I.2011 AIF

The following is the text of the 2011 AIF of Nexen.

ANNUAL INFORMATION FORM (AIF)

# APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

ANNUAL INFORMATION FORM (AIF)

Below is a list of terms specific to the oil and gas industry. They are used throughout this AIF.

| | | | |
|---|---|---|---|
| /d | = per day | boe | = barrel of oil equivalent on the basis of 1 bbl to 6 mcf of natural gas |
| bbl | = barrel | mboe | = thousand barrels of oil equivalent |
| mbbls | = thousand barrels | mmboe | = million barrels of oil equivalent |
| mmbbls | = million barrels | mcf | = thousand cubic feet |
| mmbtu | = million British thermal units | mmcf | = million cubic feet |
| km | = kilometre | bcf | = billion cubic feet |
| MW | = megawatt | WTI | = West Texas Intermediate |
| GWh | = gigawatt hours | Brent | = Dated Brent |
| GJ | = gigajoules | NGL | = natural gas liquid |
| PSCTM | = Premium Synthetic CrudeTM | NYMEX | = New York Mercantile Exchange |
| AECO | = natural gas storage facility located in Alberta | $000s or $M | = thousands of dollars |
| $MM | = millions of dollars | US$ | = United States dollars |

## GENERAL INFORMATION

In this Annual Information Form (AIF), references to “we”, “our”, “us”, “Nexen” or the “Company” mean Nexen Inc., our subsidiaries and partnerships.

Unless we indicate otherwise, all dollar amounts ($) are in Canadian dollars, and oil and gas volumes, reserves and related performance measures are presented on a working interest before-royalties basis. Where appropriate, information on an after-royalties basis is provided. The information contained in this AIF is dated December 31, 2011, unless otherwise indicated. The date of this discussion is February 15, 2012.

Conversions of gas volumes to boe in this AIF were made on the basis of 1 boe to 6 mcf of natural gas. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. Using the forecast prices applied to our reserves estimates, the boe conversion ratio based on wellhead value is approximately 30 mcf:1 bbl.

### Accounting Matters

In February 2008, the Canadian Institute of Chartered Accountants announced that publicly accountable enterprises must adopt International Financial Reporting Standards (IFRS) by January 1, 2011. Accordingly, our consolidated balance sheet as at January 1, 2010 and the results of operations for the years ended December 31, 2011 and 2010 have been prepared in accordance with IFRS. The financial information presented in the 2011 AIF, Management's Discussion & Analysis (MD&A) and Consolidated Financial Statements has been prepared in accordance with IFRS as issued by the International Accounting Standards Board (IASB). In accordance with the Canadian IFRS transition rules, financial information before 2010 has not been restated. A description of the transition from previous Canadian generally accepted accounting principles (GAAP) to IFRS is included in Note 26 of our Consolidated Financial Statements.

Non-GAAP Measures

Certain financial measures referred to in this AIF, namely "cash flow from operations" and "net debt" do not have a standardized meaning prescribed by GAAP and are therefore unlikely to be comparable to similar measures presented by others. These non-GAAP measures are included to assist investors in analyzing Nexen's operating performance, leverage and liquidity. Reconciliations of these non-GAAP measures to their nearest GAAP equivalent are included in our MD&A.

Foreign Exchange

The noon-day Canadian to US dollar exchange rates for Cdn$1.00, as reported by the Bank of Canada, were:

| (US$) | December 31 | Average | High | Low |
|---|---|---|---|---|
| 2007 | 1.0120 | 0.9304 | 1.0905 | 0.8437 |
| 2008 | 0.8166 | 0.9381 | 1.0289 | 0.7711 |
| 2009 | 0.9555 | 0.8757 | 0.9716 | 0.7692 |
| 2010 | 1.0054 | 0.9709 | 1.0054 | 0.9278 |
| 2011 | 0.9833 | 1.0117 | 1.0583 | 0.9430 |

On January 31, 2012, the noon-day exchange rate was US$0.9948 for Cdn$1.00.

## FORWARD-LOOKING STATEMENTS

Certain statements in this AIF constitute "forward-looking statements" (within the meaning of the United States Private Securities Litigation Reform Act of 1995, as amended) or "forward-looking information" (within the meaning of applicable Canadian securities legislation). Such statements or information (together "forward-looking statements") are generally identifiable by the forward-looking terminology used such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook", "forecast" or other similar words and include statements relating to, or associated with, individual wells, regions or projects. Any statements as to possible future crude oil or natural gas prices; future production levels; future royalties and tax levels; future capital expenditures, their timing and their allocation to exploration and development activities; future earnings; future asset acquisitions or dispositions; future sources of funding for our capital program; future debt levels; availability of committed credit facilities; possible commerciality of our projects; development plans or capacity expansions; the expectation that we have the ability to substantially grow production at our oil sands facilities through controlled expansions; the expectation of achieving the production design rates from our oil sands facilities; the expectation that our oil sands production facilities continue to develop better and more sustainable practices; the expectation of cheaper and more technologically advanced operations; the expected design size of our facilities; the expected timing and associated production impact of facility turnarounds and maintenance; the expectation that we can continue to operate our offshore exploration, development and production facilities safely and profitably; future ability to execute dispositions of assets or businesses; future sources of liquidity, cash flows and their uses; future drilling of new wells; ultimate recoverability of current and long-term assets; ultimate recoverability of reserves or resources; expected finding and development costs; expected operating costs; the expectation of our ability to comply with the new safety and environmental rules at a minimal incremental cost, and of receiving necessary drilling permits for our US offshore operations; estimates on a per share basis; future foreign currency exchange rates; future expenditures and future allowances relating to environmental matters and our ability to comply therewith; dates by which certain areas will be developed, come on-stream or reach expected operating capacity; and changes in any of the foregoing are forward-looking statements.

Statements relating to "reserves" or "resources" are forward-looking statements, as they involve the implied assessment, based on estimates and assumptions that the reserves and resources described exist in the quantities predicted or estimated and can be profitably produced in the future.

All of the forward-looking statements in this AIF are qualified by the assumptions that are stated or inherent in such forward-looking statements. Although we believe that these assumptions are reasonable based on the information available to us on the date such assumptions were made, this list is not exhaustive of the factors that may affect any of the forward-looking statements and the reader should not place an undue reliance on these assumptions and such forward-looking statements. The key assumptions that have been made in connection with the forward-looking statements include the following: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve volumes; commodity price and cost assumptions; the continued availability of adequate cash flow and debt and/or equity financing to fund our capital and operating requirements as needed; and the extent of our liabilities. We believe the material factors, expectations and assumptions reflected in the forward-looking statements are reasonable, but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

Forward-looking statements are subject to known and unknown risks and uncertainties and other factors, many of which are beyond our control and each of which contributes to the possibility that our forward-looking statements will not occur or that actual results, levels of activity and achievements may differ materially from those expressed or implied by such statements. Such factors include, but are not limited to: market prices for oil and gas; our ability to explore, develop, produce, upgrade and transport crude oil and natural gas to markets; ultimate effectiveness of design or design modifications to facilities; the results of exploration and development drilling and related activities; the cumulative impact of oil sands development on the environment; the impact of technology on operations and processes and how new complex technology may not perform as expected; the availability of pipeline and global refining capacity; risks inherent to the operations of any large, complex refinery units, especially the integration between production operations and an upgrader facility; availability of third-party bitumen for use in our oil sands production facilities; labour and material shortages; risks related to accidents, blowouts and spills in connection with our offshore exploration, development and production activities, particularly our deep-water activities; direct and indirect risks related to the imposition of moratoriums, suspensions or cancellations of our offshore exploration, development and production operations, particularly our deep-water activities; the impact of severe weather on our offshore exploration, development and production activities, particularly our deep-water activities; the effectiveness and reliability of our technology in harsh and unpredictable environments; risks related to the actions and financial circumstances of our agents, contractors, counterparties and joint-venture partners; volatility in energy trading markets; foreign currency exchange rates; economic conditions in the countries and regions in which we carry on business; governmental actions including changes to taxes or royalties, changes in environmental and other laws and regulations including without limitation, those related to our offshore exploration, development and production activities; renegotiations of contracts; results of litigation, arbitration or regulatory proceedings; political uncertainty, including actions by terrorists, insurgent or other groups, or other armed conflict, including conflict between states; and other factors, many of which are beyond our control. These risks, uncertainties and other factors and their possible impact are discussed more fully in the sections titled “Risk Factors” in this AIF and “Quantitative and Qualitative Disclosures About Market Risk” in our MD&A. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and management’s future course of action would depend on our assessment of all information at that time. Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity and achievements. Undue reliance should not be placed on the forward-looking statements contained herein, which are made as of the date hereof as the plans, intentions, assumptions or expectations upon which they are based might not occur or come to fruition. Except as required by applicable securities laws, Nexen undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. Included herein is information that may be considered financial outlook and/or future-oriented financial information (FOFI). Its purpose is to indicate the potential results of our intentions and may not be appropriate for other purposes. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

CORPORATE STRUCTURE

Nexen Inc. is incorporated under the Canada Business Corporations Act. Our registered and head office is located at 801 – 7th Avenue S.W., Calgary, Alberta, Canada T2P 3P7.

Our material operating subsidiaries owned directly or indirectly and their jurisdictions of incorporation as at December 31, 2011 are as follows:

| Name of Subsidiary | Jurisdiction of Incorporation/ Formation/Continuation |
|---|---|
| Nexen Petroleum UK Limited | England & Wales |
| Nexen Petroleum Nigeria Limited | Nigeria |
| Nexen Petroleum Offshore USA Inc. | Delaware |
| Nexen Marketing | Alberta |
| Canadian Nexen PetroleumYemen | Yemen |
| Nexen Oil Sands Partnership | Alberta |

All material operating subsidiaries are 100% beneficially owned, controlled or directed by us.

BUSINESS OVERVIEW

Nexen Inc. is an independent, Canadian-based, global energy company. We were formed in Canada in 1971 as Canadian Occidental Petroleum Ltd. when Occidental Petroleum Corporation combined their Canadian crude oil, natural gas, sulphur and chemical operations into one company.

Strategy

We create value by producing the energy resources that fuel people's lives. Our strategy is to capture resource early, maintain a portfolio of opportunities and create competitive advantage through technology, talent and experience. We seek to build a sustainable energy company focused on delivering on execution and exploiting our three key growth areas: i) conventional oil and gas; ii) oil sands; and iii) shale gas.

CONVENTIONAL OIL AND GAS

Our conventional oil and gas assets are comprised of large acreage positions in select basins including the UK North Sea, deep-water Gulf of Mexico and offshore West Africa. Strategically, we focus on these basins due to: i) past successes; ii) existing infrastructure in place; iii) significant potential in remaining resource; and iv) attractive fiscal terms. We assess our global portfolio of opportunities to identify prospects that we believe will generate the highest value in our selected basins.

In the UK North Sea, we are a significant regional player with concentrated assets, infrastructure and exploration potential for future growth. In addition to other producing properties, we operate the Buzzard field and platform, which is the largest discovery in the UK North Sea in over a decade. Other recent discoveries at Golden Eagle, Telford TAC and Rochelle are under development and are expected to provide new sources of production in the short-term. We continue to actively explore the UK North Sea basin including relatively under-explored areas such as west of the

Shetland Islands.

In the Gulf of Mexico, we hold deep-water and shelf producing assets as well as several undeveloped deep-water discoveries including Appomattox, Vicksburg and Knotty Head. We are a significant leaseholder in the Gulf with access to deep-water drilling rigs. The deep-water Gulf of Mexico is near infrastructure and continental US markets.

We have several significant discoveries offshore West Africa, including Usan, Usan West, Ukot and Owowo. Development of the Usan field is nearing completion and first oil is expected in the next month or two. We are actively exploring the basin with several follow up prospects to pursue.

## OIL SANDS

Our oil sands investments include interests in the Long Lake project, the Syncrude joint venture and 656,000 undeveloped acres (gross) in the Athabasca oil sands in northern Alberta. Our oil sands strategy is to generate steady and predictable cash flow for decades. While the cost to produce from the Athabasca oil sands is higher relative to conventional oil deposits, the significant discovered resource base and stable fiscal jurisdiction make this a key source of future oil development.

We first entered the oil sands by acquiring an interest in the Syncrude joint venture. Syncrude produces synthetic crude oil from mined bitumen-saturated sands.

Our in situ oil sands project at Long Lake produces and upgrades bitumen in the Athabasca oil sands. Steam-assisted-gravity-drainage (SAGD) bitumen production began in 2008 and production of PSCTM from the upgrader began in 2009. Our near-term plans include development of the Kinosis lease, a source of in situ bitumen to provide additional feedstock for the Long Lake upgrader.

## SHALE GAS

We have over 300,000 acres of shale gas lands in the Horn River, Cordova and Liard basins in northeast British Columbia. Our shale gas strategy is currently focused primarily on the Horn River basin. The Horn River basin is a significant shale gas play with high resource density and strong well productivity. In November 2011, we signed an agreement to farm-out a 40% working interest in our shale gas lands in northeast British Columbia to a consortium led by INPEX Corporation. The sale is expected to close in the second quarter of 2012. In 2011, we expanded our shale gas portfolio by acquiring a non-operated interest in Poland and by beginning to test shale gas opportunities in Colombia.

Shale gas balances our corporate portfolio, which consists predominantly of large-scale, capital-intensive and long cycle-time projects. It provides natural gas exposure and short cycle-time projects where we control the scale and pace of development depending on the current price environment.

Three–Year Overview

20091
- Generated cash flow from operations of $2.2 billion and net income of $536 million
- Discovered the Hobby field in the UK North Sea, the first discovery of our Golden Eagle area
- Acquired an additional 15% working interest in the Long Lake project and completed first major turnaround to address steam reliability issues
- Produced first PSCTM from Long Lake
- Issued $1 billion of 10-year and 30-year senior notes
- Discovered Owowo field, offshore West Africa

2010
- Generated cash flow from operations of $2.2 billion and net income of $1.1 billion
- Discovered the Appomattox field in the deep-water Gulf of Mexico
- Disposed of non–core, heavy oil properties in Western Canada for $939 million
- Divested of non–core marketing businesses including North American natural gas marketing

- Doubled bitumen production at Long Lake with improved steam reliability
- More than doubled our British Columbia shale gas acreage, adding lands in the Cordova and Liard basins

2011

- Generated cash flow from operations of $2.4 billion and net income of $697 million
- Completed a non-core asset disposition program with the sale of our interest in Canexus for $458 million
- Repaid approximately $800 million of long-term debt
- Moored the Usan floating production and storage offloading vessel (FPSO) at site in offshore West Africa with final commissioning underway
- Developed action plans to increase production at Long Lake and fill the upgrader; ramped-up pad 11, drilled pads 12 and 13 and progressed regulatory process for pads 14, 15 and Kinosis K1A
- Commissioned the Buzzard fourth platform to handle higher levels of $H_2S$ from the field
- Achieved first oil at our Blackbird field in the UK North Sea
- Received government approval and sanctioned the Golden Eagle development in the UK
- Brought a nine-well pad on-stream and began drilling an 18-well pad at Horn River
- Entered into an agreement to farm-out a 40% working interest in our northeast British Columbia shale gas operations for $700 million

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1 Financial amounts for 2009 and earlier were prepared under previous Canadian Generally Accepted Accounting Principles and have not been restated for IFRS. Amounts for 2010 and 2011 were prepared under IFRS.

In 2012, we expect the following changes to our businesses:

- UK North Sea—progress development of our Golden Eagle discovery, bring tie-backs at Telford TAC and Rochelle on-stream and continue to explore the UK North Sea basin with seven exploration and appraisal wells planned.

- Gulf of Mexico—complete the Kakuna exploration well, continue appraisal of the Appomattox discovery and test other identified deep-water Gulf of Mexico opportunities with six exploration and appraisal wells planned.

- Offshore West Africa—complete commissioning of the Usan FPSO with first oil production in the next month or two and continue exploration of our acreage.

- Long Lake—progress towards filling the upgrader to capacity by optimizing bitumen production from additional Long Lake well pads and accelerating development of the Kinosis bitumen resource.

- Shale Gas—close the sale of the 40% working interest in our northeast British Columbia shale gas operations, bring the first 18-well pad on stream and expand field processing capacity at Horn River and continue exploration activities in Poland and Colombia.

OIL AND GAS

In this AIF, we provide estimates of remaining quantities of proved and probable crude oil, synthetic oil, bitumen, coal bed methane (CBM), shale gas and natural gas reserves (oil and gas reserves) for our various properties as at December 31, 2011. These reserves estimates and related disclosures have been prepared in accordance with National Instrument 51-101—Standards of Disclosure for Oil and Gas Activities (NI 51-101). We have also prepared reserves estimates and disclosures in accordance with SEC requirements, which are included in Appendix B of this AIF. Reserves estimates and disclosures prepared in accordance with NI 51-101 requirements differ from reserves estimates prepared in accordance with SEC requirements. Significant qualitative differences between NI 51-101 and SEC reserves estimates and disclosures are described in the section entitled "Special Note to Investors" on page 40.

Our proved and probable reserve estimates have been internally prepared. For our reserves estimates prepared in accordance with NI 51-101 requirements, we had 96% of our proved reserves assessed (either evaluated or audited as described on pages 37 to 38) by independent reserves consultants. Their assessment of the proved reserves is performed at varying levels of property aggregation, and we work with them to reconcile any difference on the portfolio of properties to within 10% in the aggregate. Estimates pertaining to individual properties within the portfolio may differ by more than 10% either positively or negatively, however, we believe such differences are not material relative to our total proved reserves.

We also had 98% of our NI 51-101 proved plus probable oil and gas reserves estimates assessed by independent reserves consultants. By definition, proved reserves must be determined together with probable reserves (see definition on page 39). As such, the independent reserves consultants' assessments are prepared on a combined proved plus probable basis. Like proved reserves, their assessment of the proved plus probable reserves is performed at varying levels of property aggregation, and we work with them to reconcile any difference on the portfolio of properties to within 10% in the aggregate. Estimates pertaining to individual properties within the portfolio may differ by more than 10% either positively or negatively, however, we believe such differences are not material relative to our total proved plus probable reserves.

Refer to the section on Basis of Reserves Estimates on pages 21 to 22 for a description of our internal reserves process and the nature and scope of the independent assessments performed on our proved and probable reserves estimates and the results thereof.

## UNDERSTANDING THE OIL AND GAS INDUSTRY

The oil and gas industry is highly competitive. With strong global demand for energy and limited exploration opportunities, there is intense competition to find and develop new sources of supply. Yet, barrels from different reservoirs around the world do not have equal value. Their value depends on the costs to find, develop and produce the oil or gas, the fiscal terms of the host regime and the price that products attract based on quality, location and marketing efforts. We captured an inventory of opportunities in our core growth areas, and our goal is to extract the maximum value from each barrel of oil equivalent so that every dollar of capital we invest generates an attractive return.

Numerous factors can affect this. Changes in crude oil and natural gas prices can significantly affect our net income and cash flow generated from operations. Consequently, these prices may also affect the carrying value of our oil and gas properties and how much we invest in oil and gas exploration and development. We attempt to reduce these impacts by investing in projects we believe will generate positive returns at relatively low commodity prices, and we maintain liquidity that provides us with the ability to sustain capital investment in high-quality projects during periods of low commodity prices.

The prices we receive for our oil and gas products are determined by global crude oil and regional natural gas markets, all of which can be volatile. With many alternative customers, the loss of any one customer is not expected to have a materially adverse effect on the price of our products or revenues. Oil and gas producing operations are generally not seasonal. However, demand for some of our products such as natural gas can fluctuate season to season, which impacts price. We manage our operations on a country-by-country basis, reflecting differences in the regulatory regime, competitive environments and risk factors associated with each country.

Presentation of our oil and gas operations is separated between conventional oil and gas activities, and oil sands activities. Our conventional operations include our oil and gas operations in the UK North Sea, North America (excluding oil sands) and other countries (Yemen, offshore West Africa, Colombia and other). Our oil sands activities are segregated between in situ oil sands operations (primarily at Long Lake) and our interest in Syncrude. Our shale gas results are included in the North America segment until they become significant.

Production, revenues, net income, capital expenditures and identifiable assets for these segments appear in Note 25 to the Consolidated Financial Statements and in our MD&A.

CONVENTIONAL OIL AND GAS

United Kingdom (UK) – North Sea

- We are the second largest oil producer in the UK North Sea.
- We are developing our Golden Eagle discovery, with first oil expected in late 2014.
- We continue to actively explore the North Sea, with seven exploration and appraisal wells planned for 2012.

The UK North Sea is a key producing area for Nexen. Our primary assets, which we operate, include a 43.2% interest in the Buzzard field and facilities, a 41.9% interest in the Scott field and production platform, an 80.4% interest in the Telford field, a 79.7% interest in the Ettrick field and a 90.6% interest in the Blackbird field, along with interests in several undeveloped discoveries and approximately 971,000 net undeveloped exploration acres. We are a significant regional player with concentrated assets, infrastructure and exploration potential for future growth. Our UK North Sea operations complement our global portfolio with significant cash flow generation and the opportunity for short cycle-time production growth.

Our UK strategy is to grow our existing North Sea production and identify new sources of production. To do this, we identify exploration and exploitation opportunities near existing infrastructure that can be tied-in economically in a short time period. We also seek to establish new core areas through exploration in relatively unexplored areas of the basin (e.g. west of Shetlands, the Central Graben and the northern North Sea). We target oil-focused assets that are early life and generate strong cash margins.

BUZZARD

The Buzzard field is located about 60 miles northeast of Aberdeen in the Outer Moray Firth, central North Sea, in 317 feet of water. Buzzard is the largest discovery in the UK North Sea in over a decade. It was discovered in 2001 and came on stream in early 2007. The Buzzard development was initially comprised of three platforms capable of processing at least 200,000 bbls/d of oil and 60 mmcf/d of gas. A fourth platform with production-sweetening facilities to handle higher levels of hydrogen sulphide was completed in 2011. Oil from Buzzard is exported via the Forties pipeline to the Kinneil Terminal in Scotland. Gas is exported via the Frigg system to the St. Fergus Gas Terminal in northeast Scotland.

We expect to produce the Buzzard field through 36 production wells and maintain reservoir pressure with an active water-flood program. We have drilled 30 of these wells to date. Our share of production in 2011 was 62,400 boe/d. In 2012, we expect to drill five additional production wells and one appraisal well in the Buzzard field.

SCOTT/TELFORD

The Scott field began producing in 1993, while Telford was tied back to the Scott platform and came on stream in 1996. Most of our oil and gas from these fields is produced through subsea wells tied back to the Scott platform. Oil is delivered to the third-party Kinneil Terminal in Scotland via the Forties pipeline, while gas is exported via the SAGE pipeline to the St. Fergus Gas Terminal in northeast Scotland. Recently, successful extension drilling of the Telford field exceeded expectations and extended the field's proved reserves. The TAC and TAE Telford development wells are expected to be on stream in 2012 and 2013, respectively. The nearby Rochelle gas field is planned to be tied back to the Scott platform in 2012. Scott/Telford produced 13,000 boe/d (net to us) in 2011. We plan to drill two additional development wells in 2012 at Telford.

ETTRICK/BLACKBIRD

Ettrick is a producing field originally discovered in 1981 and brought on stream in 2009. Oil and gas is produced from the fields through seven subsea wells tied back to a leased FPSO. The FPSO is designed to handle 30,000 bbls/d of oil and 35 mmcf/d of gas and to re-inject 55,000 bbls/d of water. The produced oil is offloaded from the FPSO onto tankers and typically delivered to ports in the North Sea. Production from the nearby Blackbird field came on stream late in 2011 and is produced through the Ettrick FPSO. Our share of production from Ettrick/Blackbird in 2011 was 14,000 boe/d. We expect to drill two development wells in 2012, one in each field.

GOLDEN EAGLE

In 2007, we made a discovery at Golden Eagle, followed by Peregrine (formerly Pink) in 2008 and Hobby in 2009. We refer to these three discoveries as the Golden Eagle area and hold a 36.5% operated interest. Since the original discovery, we successfully completed a comprehensive appraisal program, which included drilling nine appraisal wells, two drill-stem tests and one injection test. In 2011, we completed the appraisal work, explored additional acreage, sanctioned the development plan and received government approval. The Golden Eagle development will include a two-platform stand-alone facility with production capacity of about 70,000 boe/d (26,000 boe/d net to us) at full rates. In 2012, we expect to advance the development of the Golden Eagle area and begin to fabricate the platforms and facilities. Development drilling in the field is expected to start in 2013 and first oil is expected in late 2014. Our net investment is expected to be $1.2 billion over the next three years.

EXPLORATION

We hold approximately 68 blocks in the UK North Sea. We continue to actively explore the basin and hold several undeveloped discoveries on operated blocks near the Golden Eagle, Scott and Buzzard facilities as follows:

| Field | Interest (%) | Operator Status | Comments |
|---|---|---|---|
| Blackhorse | 50 | operated | discovery near Scott, evaluating development alternatives |
| Bright | 80 | operated | discovery near Buzzard, evaluating development alternatives |
| Bugle | 100 | operated | discovery near Scott, evaluating development alternatives |
| Kildare | 50 | operated | discovery near Scott; evaluating development alternatives |
| Marten | 40 | operated | discovery near Buzzard, evaluating development alternatives |
| Polecat | 100 | operated | discovery near Buzzard; evaluating development alternatives |
| Samedi | 100 | operated | discovery near Golden Eagle, evaluating development alternatives |

In the UK North Sea, we plan to drill a total of four exploration wells and three appraisal wells in 2012.

United States (US) — Gulf of Mexico

- We are a significant leaseholder in the deep-water Gulf of Mexico.
- We are appraising our Appomattox discovery in the emerging Norphlet play.

The deep-water Gulf of Mexico is an integral part of our growth strategy. Existing production infrastructure, the potential for material discoveries and attractive fiscal terms make the deep-water Gulf of Mexico one of the world's most prospective basins for oil and gas. While costs of deep-water exploration are typically higher, prospects generally have multiple sands and higher production rates—factors that can enhance economics. The deep-water Gulf is near infrastructure and continental US markets, so discoveries can be brought on stream in reasonable time frames relative to less developed or more remote areas of the world. We currently focus our exploration program on Miocene sub-salt plays and Norphlet targets in the central Gulf of Mexico.

Over the past few years, we have built our resources and capabilities to explore in the deep water by accumulating a large inventory of high-quality acreage and gained access to two new-build deep-water drilling rigs.

Our existing Gulf of Mexico production and reserves are primarily concentrated in six deep—water and four shallow—water (shelf) areas. Our oil and natural gas production is transported to the continental US for sale via third-party pipelines and infrastructure. Our share of production from the Gulf of Mexico in 2011 was 22,600 boe/d (20,400 boe/d after royalties).

DEEP WATER

Most of our deep-water production comes from our 25% non-operated Longhorn field, our 100% operated Aspen field, our 50% non-operated Wrigley field, and our 30% non-operated Gunnison field. Our share of 2011 deep-water production before royalties was 16,400 boe/d (15,300 boe/d after royalties).

Our Longhorn property is on Mississippi Canyon Blocks 502 and 546 in 2,400 feet of water. The project is a non-operated four-well subsea tie-back to the Corral platform located 19 miles north of the field. Longhorn came on stream in late 2009 and produced 7,900 boe/d (net to us) in 2011.

Aspen is on Green Canyon Block 243 in 3,150 feet of water. The project was developed using four subsea oil wells tied back to the third-party operated Bullwinkle platform 16 miles away and began producing in late 2002.

Wrigley is on Mississippi Canyon Block 506 in 3,300 feet of water. The project began gas production in 2007 and consists of a single subsea well tied back to the Shell-operated Cognac platform 17 miles away.

Gunnison is in 3,100 feet of water and includes Garden Banks Blocks 667, 668 and 669. Gunnison began production in late 2003 through a truss SPAR platform that can handle 40,000 bbls/d of oil and 200 mmcf/d of gas.

Green Canyon 6/137 is in water depths of 650 feet. Production from this field is currently suspended as the third-party platform that processed our oil and gas was destroyed by Hurricane Ike in September 2008. A tie-back to existing third-party facilities to restore production is under construction and production is expected to resume in 2012.

SHELF

Our shelf producing assets are offshore Louisiana, primarily in four 100%-owned field areas: Eugene Island 255/257/258/259, Eugene Island 295, Vermilion 76 and West Delta. Given the mature nature of these assets, our 2012 capital investment on these assets is expected to be minimal.

EXPLORATION

We hold approximately 205 blocks in the Gulf of Mexico and expect this acreage and future exploration opportunities to position us for growth. Our undeveloped deep-water discoveries include:

| Well | Interest (%) | Operator Status | Comments |
|---|---|---|---|
| Appomattox | 20 | non-operated | discovery; appraisal underway |
| Knotty Head | 25 | non-operated | discovery; currently evaluating development options |
| Vicksburg | 25 | non-operated | discovery; further appraisal required |

In 2010, we completed a successful exploration well and sidetrack at Appomattox, approximately six miles west of our Vicksburg discovery. Results of these activities indicated a significant oil discovery with the potential to extend the discovery. In 2011, appraisal drilling recommenced at Appomattox following the end of the US Government drilling moratorium. In early 2012, a successful well on the northeast fault block encountered oil play and we are completing an evaluation to determine the size of the discovery. Additional wells are planned in 2012 to further delineate these discoveries. During 2011, we progressed development studies at Knotty Head and began drilling operations at Kakuna, a 52.5% operated deep-water exploration well targetting the Miocene sub-salt play. Results from this well are expected in 2012. In 2011, we received a drilling permit from the US Government to drill the deep-water Angel Fire prospect, which we expect to spud during 2012.

In 2012, we plan to drill up to six exploration and appraisal wells in the deep-water Gulf of Mexico, focusing on the Miocene sub-salt play and following up on the success in the Norphlet play.

Other International

- Our entry into Yemen kicked off our international expansion in the early 1990s, which provided us with other international opportunities.
- Development of the Usan field, offshore Nigeria is nearing completion and first oil production is expected in the next month or two.
- In Nigeria, we have several discoveries and additional exploration prospects beyond Usan.

NIGERIA

Offshore West Africa is a core area with several discoveries that offer relatively low risk exploration for prolific reservoirs supported by 3D seismic data. Our strategy here is to complete development of the Usan discovery and continue to explore our existing portfolio of multiple prospects in this oil-rich region to provide medium to long-term growth.

In 1998, we acquired a 20% non-operated interest in Block OPL-222, which covers 448,000 acres approximately 80 km offshore in water depths ranging from 200 to 1,200 metres. In 1998, we discovered the Ukot field comprised of three oil-bearing intervals and in 2002, the Usan field was discovered, with seven successful wells confirming the presence of significant hydrocarbon accumulations. In 2007, OPL-222 was converted to two Oil Mining Leases, OML-138 and 139. The Usan development is within OML-138.

Development of the Usan field is progressing and expected to come on stream in the next month or two, with peak facility capacity of 180,000 bbls/d (36,000 bbls/d, net to us). The FPSO and initial subsea facilities were completed and installed in the field during 2011. The FPSO, capable of storing up to two million barrels of oil, is undergoing final hook-up and commissioning. Oil will be offloaded onto tankers for delivery to customers.

In 2008, we acquired an 18% non-operated interest in Block OPL-223, covering 230,000 acres, which provides us with significant exploration potential contiguous with our other licenses. In 2009, we drilled the Owowo South B-1 exploration well in the southern portion of Block OPL-223, in 670 metres of water, 20 km east of the Usan field. Under the Production Sharing Contract governing OPL-223, the Nigerian National Petroleum Corporation is the concessionaire of the license. All of our licenses in Nigeria are operated by Total Exploration & Production Nigeria Ltd. We are planning a multi-well exploration and appraisal drilling program in 2012 to test and delineate our Nigeria portfolio.

As is typical in many jurisdictions, the Nigerian government is reviewing its existing petroleum fiscal terms, including those applicable to our interests, the impact of which could negatively affect the economics of our projects.

## YEMEN

Yemen was a significant international region for us since we first began production at Masila on Block 14 in 1993. We operated Masila, the country's largest oil project, for 18 years and developed strong relationships with the government and local communities. On December 17, 2011, the Masila production sharing agreement (PSA) expired and production, operations, central processing facility, main oil pipeline and export facilities were transferred to the Yemen Government. We continue to operate the East Al Hajr facility (Block 51) and our strategy is to maximize the remaining value of the block.

Production from Yemen in 2011 was 32,900 bbls/d (18,100 bbls/d after royalties).

### East Al Hajr Block (Block 51)

The first successful exploratory well was drilled in 2003 and development of the block began in 2004, which included a central processing facility (CPF), gathering system and a 22 km tie-back to an export oil pipeline. Production commenced in late 2004 and approximately 69 wells are currently on stream. Oil is delivered to customers via tankers in the Gulf of Aden.

We operate Block 51, which is governed by the Block 51 PSA between the Government of Yemen and the East Al Hajr partners (EAH Partners); The Yemen Company (TYCO) (12.5% carried working interest) and Nexen (87.5% working interest). Under the PSA, TYCO has no obligation to fund capital or operating expenditures and, therefore, our effective interest is 100% and, for purposes of accounting and reserves recognition, we treat TYCO's 12.5% participating interest as a royalty interest. The PSA expires in 2023.

## COLOMBIA

In 2000, we made a discovery at Guando on our 20% non-operated Boqueron Block, and production from the Guando field began in 2001. Boqueron is in the Upper Magdalena Basin of central Colombia, approximately 100 km southwest of Bogota. Under terms of our licence, our working interest in Guando decreased from 20 to 10% during the second quarter of 2009, as cumulative oil production from the field reached 60 million barrels. Our share of production in Colombia in 2011 was 1,700 bbls/d (1,600 bbls/d after royalties).

We currently hold interests in six exploration and production blocks in the Upper Magdalena Basin and the Eastern Cordillera area. In the Upper Magdalena Basin, we hold a 10% interest in the Boqueron block and a 50% non-operating interest in the Villarrica Norte Block. In the Eastern Cordillera area, we hold a 100% interest in the Chiquinquira, Sueva, Barbosa and Garagoa exploration and production blocks.

## OIL SANDS

- We operate the Long Lake project, an integrated SAGD and upgrader process.
- Syncrude has been operating for over 30 years and provides steady predictable cash flows.
- We have significant undeveloped acreage in the Athabasca oil sands, totaling over 656,000 acres (gross).

The Athabasca oil sands deposit in northeast Alberta is a key growth area for us. Our strategy is to economically develop our bitumen resource in phases to provide low-risk, stable, future growth. Our operated project at Long Lake involves integrating SAGD bitumen production with field-upgrading technology to produce PSCTM for sale, and synthetic gas, which significantly reduces our need to purchase natural gas for operations. We have a 7.23% investment in the Syncrude oil sands mining and upgrading operation, as well as significant undeveloped acreage.

### In Situ Oil Sands

In 2001, we formed a joint venture with OPTI Canada Inc. (OPTI) to develop the Long Lake lease using SAGD for in situ bitumen production and proprietary OrCrudeTM technology for the first stage of upgrading the bitumen to PSCTM. OPTI has the exclusive Canadian licence for the OrCrudeTM technology. We acquired the exclusive right to use this technology with OPTI within approximately 160 km of Long Lake, and the right to use the technology elsewhere in Canada and the rest of the world (excluding Israel) subject to certain rights of OPTI to participate.

SAGD bitumen operations at Long Lake started mid-2008 and we began producing PSCTM from the upgrader in 2009. Early in 2009, we acquired an additional 15% interest in the Long Lake project and the joint venture lands from OPTI, increasing our ownership level to 65%. Following the acquisition, we are responsible for operating the entire project.

In 2011, Chinese National Offshore Oil Company acquired OPTI, which included the 35% non-operated interest in the Long Lake project and joint venture lands.

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## SAGD AND UPGRADER INTEGRATION

The SAGD process involves drilling two parallel horizontal wells about 16 feet apart, with horizontal portions generally between 2,300 and 3,300 feet long. Steam is injected into the shallower well, where it heats the bitumen that then flows by gravity to the deeper producing well. The OrCrudeTM technology, using conventional distillation, solvent de-asphalting and thermal cracking, separates the produced bitumen into partially upgraded sour crude oil and liquid asphaltenes. By coupling the OrCrudeTM process with commercially available hydrocracking and gasification technologies, sour crude oil is upgraded to light (39° API) PSCTM , and the asphaltenes are converted to a low-energy, synthetic fuel gas. This gas is available as a low-cost fuel for generating steam and as a source of hydrogen for the hydrocracking process. The gas is also consumed in a dual 85 MW unit cogeneration plant to produce electricity for on-site use and sale to the provincial electricity grid. The energy conversion efficiency for our Long Lake upgrader is about 90%, compared to 75% for a typical bitumen-fed coker based plant.

## LONG LAKE AND KINOSIS PROJECTS

The Long Lake project is located approximately 40 km southeast of Fort McMurray, Alberta and operations include steam generation and water treatment facilities, cogeneration plant, SAGD operations and an onsite upgrader. Bitumen is produced from the McMurray reservoir through 90 well pairs located on 11 pads. Steam generation capacity is 228,000 bbls/d from six once-through steam boilers (46% of total capacity) and two cogeneration units (54% of total capacity).

The first several months of steam injection into a well pair largely involve heating the reservoir, followed by a ramp-up of bitumen production to peak rates over 12 to 24 months. At the start of production, steam-to-oil ratios (SORs) are high but are expected to decline as bitumen production ramps up to our target rates. We expect the SOR to be in the range of three to four over the long term.

We completed drilling 10 wells on pad 11 during 2011 with first production from the initial wells mid year. We currently produce 4,500 bbls/d (gross) from this pad and expect to produce 4,000 to 8,000 bbls/d (gross) at maturity. We expect to begin steaming the 18 well pairs on pads 12 and 13 in the spring and fall of 2012, respectively, with first oil expected three months later, thereafter ramping up over 12 to 18 months. We expect production from these two pads will contribute 11,000 to 17,000 bbls/d (gross) at maturity.

SAGD bitumen production in 2011 averaged 28,600 bbls/d gross (18,600 bbls/d net to us) and we are currently producing approximately 35,000 bbls/d gross (22,800 bbls/d net to us).

Initially, we expected to fill the upgrader from the first 11 pads that are now on-stream; however, we underestimated the impact lean zones and shales would have on production rates and steam-oil ratio (SOR). We better understand the correlation between reservoir characteristics, production and SOR, based on the range of well performance we experienced in the initial wells. This understanding allows us to target the best quality resource for development that is analogous to the wells in our initial set that are exhibiting good performance. It also confirms that our oil sands lands, including undeveloped areas on the Long Lake lease, contain attractive resource. We expect production from pads 1 to 11 to continue to increase over time from additional steam, heating through the lean zones, the ramp-up of wells as they mature, and well work-over activities.

In 2011, we adjusted our oil sands resource development strategy to accelerate increasing bitumen production for filling the upgrader. Our strategy for filling the upgrader includes:

- maintain production from the initial 10 pads;
- ramp-up of pad 11;
- start-up of pads 12 and 13, where steaming is expected in 2012;
- drilling of pads 14 and 15, which are expected to commence drilling in 2012, with first steam in 2013;
- acceleration of development of high quality resource from Kinosis (K1A);
- drilling additional core holes to identify future drilling locations on the Long Lake and Kinosis leases; and
- processing third-party sourced bitumen in the interim to enhance returns.

We are working through the engineering and regulatory processes to develop 25 to 30 well pairs on the Kinosis lease, which is located along the southern border of Long Lake (known as K1A). These wells will be drilled in bitumen resource where our extensive core hole analysis and reservoir understanding indicates that the geological characteristics, including minimal lean zones and shale barriers, are similar to our higher producing areas. Assuming regulatory approval, drilling is expected in 2012 or 2013, with first steam injection in early 2014. We expect production from these wells will contribute 15,000 to 25,000 bbls/d (gross).

To further evaluate our Long Lake and Kinosis leases for future development, a 200 well core-hole drilling program is expected to be completed this winter. This program supports our sustaining development activities to keep the Long Lake upgrader full and to begin developing the remainder of the Kinosis lease.

We expect to maintain bitumen production over the project’s life, estimated in excess of 50 years, by periodically drilling additional SAGD well pairs.

Initial production of PSCTM oil from the upgrader began in 2009. The upgrader consists of the OrCrudeTM unit, air separation unit, hydro-cracker, sulphur recovery facilities and gasifier. Production design capacity for the Long Lake upgrader is approximately 60,000 bbls/d (39,000 bbls/d net to us) of PSCTM. We are progressing projects that will increase the operating independence between our SAGD facilities and upgrader while maintaining the benefits of integration. The facilities are able to import between 10,000 and 15,000 bbls/d of third party bitumen to process into PSCTM through the upgrader.

In 2011, we processed about 31,500 bbls/d gross (20,500 bbls/d net to us) of proprietary and third-party bitumen through the upgrader, producing 22,800 bbls/d gross (14,800 bbls/d net to us) of PSCTM. Our operations include storage capacity of 430,000 bbls on site. PSCTM is transported via the Athabasca Pipeline to Hardisty and sold to customers in Canada and the US.

Combined SAGD, cogeneration and upgrading operating costs are expected to average about $35/bbl once we reach design capacities. We expect ongoing capital costs to average approximately $10/bbl depending on well spacing, well length and recovery factor. The full-cycle capital costs of producing and upgrading bitumen using this technology are comparable to those for surface mining and coking upgrading on a barrel-of-daily production basis.

OTHER PROJECTS

Engineering and regulatory work is underway on the non-operated SAGD project at Hangingstone. We have a 25% interest in this project. Project sanctioning is expected in 2012 with first steam in 2016. Our share of production at full rates is expected to be 6,000 bbls/d.

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Syncrude

We hold a 7.23% participating interest in the Syncrude joint venture. This joint venture was established in 1975 to mine shallow oil sand deposits using open-pit mining methods, extract the bitumen and upgrade it to a high-quality, light (32° API), sweet, synthetic crude oil. Syncrude's operating strategy is to develop this resource, focusing on safe, reliable and profitable operations.

Syncrude exploits a portion of the Athabasca oil sands that contains bitumen in the unconsolidated sands of the McMurray formation. Ore bodies are buried beneath 50 to 150 feet of over-burden, have bitumen grades ranging from 4 to 14% by weight and ore-bearing sand thickness of 100 to 160 feet. Syncrude's operations are on eight leases (10, 12, 17, 22, 29, 30, 31 and 34) covering 248,300 acres, 40 km north of Fort McMurray in northeast Alberta. Syncrude currently mines oil sands at two mines: Mildred Lake North and Aurora North. Trucks and shovels are used to collect the oil sands in the open-pit mines. The oil sands are transferred for processing using a hydro-transport system.

The extraction facilities, which separate bitumen from oil sands, are capable of processing more than 310 million tons of oil sands per year and between 140 and 160 million barrels of bitumen per year depending on the average bitumen ore grade. To extract bitumen, the oil sands are mixed with water to form a slurry. Air and chemicals are added to separate bitumen from the sand grains. The process at the Mildred Lake North Mine uses hot water, steam and caustic soda to create a slurry, while at the Aurora North Mine, the oil sands are mixed with warm water. Close to 90% of the water used in operations is recycled from the upgrader and mine sites. Incremental water is drawn from the Athabasca River in accordance with existing licences.

The extracted bitumen is fed into a vacuum distillation tower and three cokers for primary upgrading, which ultimately become light, sweet, synthetic crude oil. Sulphur and coke, which are by-products of the process, are stockpiled for possible future sale.

The high quality of Syncrude's synthetic crude oil allows it to be sold at prices approximating WTI. In 2011, about 45% of the synthetic crude oil was sold to refineries in Eastern Canada, 40% to those in the mid-western United States and the remaining 15% was sold to refineries in the Edmonton area. Electricity is provided to Syncrude from two generating plants on site: a 270 MW plant and an 80 MW plant.

Since operations started in 1978, Syncrude has shipped more than two billion barrels of synthetic crude oil to Edmonton by Alberta Oil Sands Pipeline Ltd. The pipeline was expanded in 2004 and 2009 to accommodate increased Syncrude production.

In 1999, the Alberta Energy and Utilities Board (AEUB) extended Syncrude's operating licence for the eight oil sands leases through to 2035. The licence permits Syncrude to mine oil sands and produce synthetic crude oil from approved development areas on the oil sands leases. The leases are automatically renewable as long as oil sands operations are ongoing or the leases are part of an approved development plan. All eight leases are included in a development plan approved by the AEUB. There were no known commercial operations on these leases prior to the start-up of operations in 1978.

In 1999, the AEUB approved an increase in Syncrude's production capacity to 465,700 bbls/d. At the end of 2001, Syncrude increased its synthetic crude oil capacity to 246,500 bbls/d with the development of the Aurora North Mine, which involved extending mining operations to a new location about 40 km north of the main Syncrude site. The next expansion of Syncrude came on stream in 2006, increasing capacity to 360,000 bbls/d with the completion of the Stage 3 project.

Syncrude pays royalties to the Alberta government. Effective January 1, 2009, and consistent with other oil sands producers, Syncrude began paying royalties based on bitumen, rather than paying royalties calculated on fully upgraded synthetic crude oil. As a part of this conversion, the Alberta government will recapture royalties related to upgrader capital expenses of about $5 billion (gross) that were deducted against prior royalties from future production over a 25-year period. In connection with the transition to the revised Alberta royalty framework, Syncrude will continue to pay base royalty rates (being the greater of 25% of net bitumen-based revenues, or 1% of gross bitumen-based revenues) plus an incremental royalty of up to $975 million (our share $70.5 million) until December 31, 2015. The incremental royalty is subject to certain minimum bitumen production thresholds and is to be paid in six annual payments. This agreement is in lieu of the Syncrude owners converting to the Province of Alberta's new royalty framework that became effective January 1, 2009. After January 1, 2016, the rates under the new Alberta royalty framework will apply to the Syncrude project.

SHALE GAS

- We reached a joint venture agreement for our northeast British Columbia shale gas play to accelerate value realization.

- We brought on stream a nine—well pad in the Horn River basin during the year.

- We expanded our shale gas exploration portfolio by acquiring a non-operated exploration interest in Poland and by testing shale gas opportunities in Colombia.

As part of our growth strategy in unconventional Canadian resource plays, we have accumulated over 300,000 acres of prospective shale gas lands in northeast British Columbia. Shale gas is natural gas produced from reservoirs composed of organic shale. The gas is stored in pore spaces and fractures, or absorbed into organic matter. Recent advances in drilling and completion technology have allowed companies to access this considerable potential resource.

Our shale gas resource allows us to take advantage of emerging markets such as growing oil sands demand and potential liquid natural gas (LNG) export opportunities off the west coast. Shale gas complements our corporate oil and gas portfolio with natural gas exposure and relatively short cycle-time projects where we control the scale and pace of development of the resource. We can match the pace of drilling and field development to forecasted economic conditions.

Our Canadian production (excluding the Athabasca oil sands) is comprised of unconventional shale gas assets in northeast British Columbia and conventional producing natural gas and CBM assets in Alberta and Saskatchewan. Prior to the sale of our heavy oil assets in July 2010, Canadian production included heavy oil volumes from east-central Alberta and west-central Saskatchewan. Proceeds from the sale were $939 million and the properties were producing approximately 15,000 boe/d.

In addition to our development of the Athabasca oil sands, our strategy for Canada is three-fold: i) significantly expand our shale gas reserves and production; ii) generate new material resource play opportunities; and iii) continue to optimize value from our conventional and CBM producing assets.

NORTHEAST BRITISH COLUMBIA

We hold approximately 300,000 acres in the Horn River, Cordova and Liard basins in northeast British Columbia. Approximately 50 to 55 mmcf/d of natural gas is generated from our shale gas properties in the Horn River. This basin is a significant shale gas play with high resource density and excellent well productivity.

In 2011, we invested $398 million progressing development of our shale gas assets at Horn River. In addition to our eight-well pad completed in 2010, we drilled and completed a nine-well pad which was brought on stream in late 2011. We began drilling an 18-well pad during the year with start-up scheduled for late 2012 and associated peak volumes expected in early 2013. Our current field processing capacity is approximately 50 to 55 mmcf/d and production from our Horn River assets is limited by this constraint. We are expanding this capacity to 175 mmcf/d in 2012 in order to process additional volumes from development of the field. Current operations are produced from 23 horizontal wells via pad developments, which minimize surface disturbances. Natural gas is compressed and dehydrated with infield facilities before export to final treating facilities via producer-owned and third-party pipelines. We hold long-term take or pay capacity on the third party pipelines and facilities.

During the year, we entered into a joint venture agreement to farm-out a 40% non-operated interest in our northeast British Columbia shale gas lands for proceeds of $700 million. The sale is expected to close in the second quarter of 2012 and Nexen will remain as operator under the joint venture.

Primary tenure in the Horn River Basin is four years and drilling activity and extensions can increase this up to 18 years. Our drilling activity to date has secured tenure for 10 years on all of our Horn River lands with extensions available of up to another three years. With the tenure secured, we are able to control the pace of field development during periods of low gas prices.

Limited gas pipeline infrastructure and processing capacity in the Horn River Basin could potentially constrain early development of the play. To ensure sufficient gathering, processing and transportation capacity for our development programs, we contracted gas pipeline capacity and associated treating capacity at the Spectra-operated Fort Nelson plant. We also entered into additional agreements that allow us to participate in regional infrastructure expansion projects.

## OTHER CANADA

Conventional natural gas properties in Alberta and Saskatchewan account for 40% of our 2011 Canadian natural gas production. This production is primarily generated from our Medicine Hat/Hatton conventional fields with over 2,200 shallow gas wells on production. These properties are mature but have low decline rates and numerous infill drilling opportunities. Our future investment here is limited as a result of low natural gas prices.

Approximately 30% of our current Canadian natural gas is produced from our CBM developments in the Fort Assiniboine area of central Alberta. We began commercial operations in the Upper Mannville coals in 2005 and progressively developed opportunities on our land base with horizontal well technology. We have limited activity planned here currently as a result of lower natural gas prices.

## OTHER INTERNATIONAL

During 2011, we entered into a joint venture agreement to explore 10 concessions in Poland's Paleozoic shale play. We acquired a 40% non-operated working interest in the concessions, which encompass more than two million acres. Total capital investment by Nexen for exploration activities is estimated to be approximately $100 million over the next two years. The opportunity provides shale gas exposure to growing European gas demand where prices are significantly higher than in North America. The initial exploration well was spudded in late 2011 and results are expected in 2012.

In 2011, we commenced a drilling program for four shale gas wells on two Colombian blocks (totaling 1.5 million acres). One well was drilled in late 2011 with a total depth of 5,800 feet and we expect the remainder to be spudded during 2012. We are in the early stages of shale gas exploration here and are one of the first companies to test shale gas opportunities in Colombia.

## ENERGY MARKETING

Our energy marketing group's primary focus is to market Nexen's proprietary crude oil and natural gas production. We also engage in market optimization activities including the purchase and sale of third-party production which provides us with additional market intelligence and opportunities in order to obtain competitive pricing for our proprietary volumes. Our team leverages regional knowledge and holds capacity on key North American infrastructure. In addition to physical marketing, we take advantage of quality, time and location spreads to generate returns. We also use financial contracts, including futures, forwards, swaps and options to manage our business. Results of these activities are included in Corporate and Other.

## RESERVES, PRODUCTION AND RELATED INFORMATION

Nexen prepares and discloses reserves estimates and other information in accordance with National Instrument 51-101—Standards of Disclosure for Oil and Gas Activities (NI 51-101) and with SEC requirements. Prior to 2010, Nexen and many of our Canadian peer companies relied upon a discretionary exemption from certain requirements of NI 51-101 granted by Canadian securities regulators which permitted disclosure of reserves information in accordance with SEC requirements only. In order to maintain comparability with Canadian peer companies who began disclosing their reserves under NI 51-101, we have presented our NI 51-101 reserves and related information in this AIF. As our reserves estimates were prepared only in accordance with SEC requirements prior to 2010, our NI 51-101 reserves information is limited to 2010 and 2011.

In order to provide comparability to non-Canadian oil and gas companies, we have also prepared reserves estimates and related information in accordance with SEC requirements, which are included in Appendix B of this AIF. Refer to the Special Note to Investors on page 40 for an explanation of differences between reserves estimates prepared under NI 51-101 and SEC requirements.

Nexen has not filed with nor included in reports to any Canadian or United States federal authority or agency with any estimates of its total proved oil or gas reserves since the beginning of 2011.

Basis of Reserves Estimates

The process of estimating reserves requires complex judgments and decision-making based on available geological, geophysical, engineering and economic data. To estimate the economically recoverable oil and gas reserves and related future net cash flows, we consider many factors and make various assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs.

We believe these factors and assumptions are reasonable based on the information available to us at the time we prepared our estimates. However, there is no guarantee that the estimated reserves will be recovered and these estimates may change substantially as additional data from ongoing development activities and production performance becomes available, and as economic conditions impacting oil and gas prices and costs change. For more information as to the risks involved in the recovery of oil and gas, see "Risk Factors" on pages 44 to 51 of this AIF.

Our estimates of reserves and future net revenue are based on internal evaluations. Reserves estimates for each property are prepared at least annually by the property's reservoir engineer and geoscientists, and by divisional management familiar with the property. Our internal reserves evaluation staff consists of over 180 individuals in multifunctional teams with relevant experience in reserves evaluation, engineering and geoscience, and over 140 of these individuals are qualified reserves evaluators for the purposes of NI 51-101. These individuals are dedicated to the development and operations of the properties evaluated and have a thorough knowledge of them. We support the technical staff with up-to-date tools for geological mapping, seismic interpretation, reservoir simulation and other technical analysis. Our reserves processes are designed to use all available information to provide accurate estimates for internal business needs and external reporting requirements. Due to the extent and expertise of our internal reserves evaluation resources, our staff's familiarity with our properties, and the controls applied to the evaluation process, we believe the reliability of our internally generated estimates of reserves and future net revenue are not materially less than would be generated by an independent qualified reserves evaluator.

Our internal qualified reserves evaluator (IQRE) is responsible for the reserves data and related disclosures. This position, required under NI 51-101, was appointed by the board in December 2003. The IQRE is a professional engineer and meets all professional and statutory requirements in regards to experience, education and professional membership associated with the role. With over 29 years of experience, the IQRE has an in-depth knowledge of reserves estimation techniques and professional guidelines, and with Canadian and SEC reserves regulations and related reporting requirements. The IQRE's primary duty includes assessing whether the reserves estimates and related disclosures have been prepared in accordance with applicable regulatory requirements.

Although we have received an exemption from the NI 51-101 requirements to have our reserves estimates independently assessed, our policy is to have at least 80% of our NI 51-101 reserves estimates either evaluated or audited annually by independent qualified reserves consultants. The section entitled "Independent Reserves Evaluation" on pages 37 to 38 of the AIF describes the nature and scope of the work performed by the independent consultants and their opinions from performing this work.

An Executive Reserves Committee, including our CEO, CFO and IQRE, meet with divisional reserves personnel to review the estimates and any changes from previous estimates. The board of directors has a Reserves Review Committee (Reserves Committee) to assist the board and the Audit and Conduct Review Committee to oversee the annual review of our oil and gas reserves and related disclosures. The Reserves Committee is comprised of three or more directors, the majority of whom are independent and familiar with estimating oil and gas reserves and disclosure requirements. The Reserves Committee meets with management periodically to review the reserves process, the portfolio of properties selected by management for independent assessment, results and related disclosures. The Reserves Committee appoints and meets with the IQRE and independent qualified reserves consultants to review the scope of their work, whether they have had access to sufficient information, the nature and satisfactory resolution of any material differences of opinion, and in the case of the independent qualified reserves consultants, their independence. In the event of a proposed change to the areas of responsibility of either an independent qualified reserves consultant or the IQRE, the Reserves Committee inquires whether there have been disputes between the respective party and management.

The Reserves Committee has reviewed our procedures for preparing the reserves estimates and related disclosures, and the properties selected by management for independent assessment. The Committee reviewed the information with management and met with the IQRE and the independent qualified reserves consultants. As a result, the Reserves Committee is satisfied that the internally generated reserves estimates are reliable and free of material misstatement. Based on the recommendation of the Reserves Committee, the board has approved the reserves estimates and related disclosures in this AIF.

We have adopted a corporate policy that prescribes the procedures and standards to be followed in the evaluation of our reserves. This policy is reviewed and amended annually as required to conform to changes in law or industry accepted evaluation practices. A copy can be found on our corporate website at www.nexeninc.com.

Reserves Estimates

The reserves data set forth on the following pages summarizes our crude oil and natural gas reserves and the net present value of the future net revenue for the reserves using forecast prices and costs. The information has been prepared in accordance with the requirements of NI 51-101. The estimates and other information has an effective date of December 31, 2011 and was prepared on February 15, 2012.

Readers should review the definitions and information contained in the “Definitions” section on pages 38 to 39 in conjunction with the following tables and notes.

Figures in this statement have been rounded to the nearest 1 mmbbls or 1 bcf. As a result, some columns may not add due to rounding.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

SUMMARY OF OIL AND GAS RESERVES AS AT DECEMBER 31, 2011
Forecast prices and Costs

| | Total (mmboe) | | Synthetic Oil (mmbbls) | | Bitumen (mmbbls) | | Light & Medium Oil (mmbbls) | | Natural Gas (bcf) | | CBM (bcf) | | Shale Gas (bcf) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| Canada | | | | | | | | | | | | | | |
| Proved Developed Producing | 264 | 232 | 219 | 190 | — | — | — | — | 115 | 107 | 62 | 58 | 94 | 92 |
| Proved Developed Non-Producing | 11 | 10 | 9 | 8 | — | — | — | — | 13 | 12 | — | — | — | — |
| Proved Undeveloped | 454 | 412 | 415 | 374 | — | — | — | — | — | — | 7 | 6 | 225 | 219 |
| Total Proved | 729 | 654 | 643 | 572 | — | — | — | — | 128 | 119 | 69 | 64 | 319 | 311 |
| Probable | 1,072 | 890 | 277 | 230 | 661 | 542 | — | — | 33 | 31 | 24 | 22 | 742 | 655 |
| Total Proved Plus Probable | 1,801 | 1,544 | 920 | 802 | 661 | 542 | — | — | 161 | 150 | 93 | 86 | 1,061 | 966 |
| United Kingdom | | | | | | | | | | | | | | |
| Proved Developed Producing | 147 | 147 | — | — | — | — | 141 | 141 | 30 | 30 | — | — | — | — |
| Proved Developed Non-Producing | 5 | 5 | — | — | — | — | 5 | 5 | 1 | 1 | — | — | — | — |
| Proved Undeveloped | 50 | 50 | — | — | — | — | 45 | 45 | 34 | 34 | — | — | — | — |
| Total Proved | 202 | 202 | — | — | — | — | 191 | 191 | 65 | 65 | — | — | — | — |
| Probable | 105 | 105 | — | — | — | — | 98 | 98 | 41 | 41 | — | — | — | — |
| Total Proved Plus Probable | 307 | 307 | — | — | — | — | 289 | 289 | 106 | 106 | — | — | — | — |
| United States | | | | | | | | | | | | | | |
| Proved Developed Producing | 13 | 11 | — | — | — | — | 7 | 6 | 37 | 32 | — | — | — | — |
| Proved Developed Non-Producing | 12 | 11 | — | — | — | — | 4 | 4 | 46 | 40 | — | — | — | — |
| Proved Undeveloped | 9 | 8 | — | — | — | — | 5 | 4 | 23 | 21 | — | — | — | — |
| Total Proved | 34 | 30 | — | — | — | — | 16 | 14 | 106 | 93 | — | — | — | — |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Probable | 82 | 69 | — | — | — | — | 65 | 55 | 101 | 87 | — | — | — | — |
| Total Proved Plus Probable | 116 | 99 | — | — | — | — | 81 | 69 | 207 | 180 | — | — | — | — |
| | | | | | | | | | | | | | | |
| Other 1 | | | | | | | | | | | | | | |
| Proved Developed Producing | 5 | 4 | — | — | — | — | 5 | 4 | — | — | — | — | — | — |
| Proved Developed Non-Producing | 18 | 16 | — | — | — | — | 18 | 16 | — | — | — | — | — | — |
| Proved Undeveloped | 20 | 16 | — | — | — | — | 20 | 16 | — | — | — | — | — | — |
| Total Proved | 43 | 36 | — | — | — | — | 43 | 36 | — | — | — | — | — | — |
| Probable | 39 | 31 | — | — | — | — | 39 | 31 | — | — | — | — | — | — |
| Total Proved Plus Probable | 82 | 67 | — | — | — | — | 82 | 67 | — | — | — | — | — | — |
| | | | | | | | | | | | | | | |
| Total Company | | | | | | | | | | | | | | |
| Proved Developed Producing | 429 | 394 | 219 | 190 | — | — | 153 | 151 | 182 | 169 | 62 | 58 | 94 | 92 |
| Proved Developed Non-Producing | 46 | 42 | 9 | 8 | — | — | 27 | 25 | 60 | 53 | — | — | — | — |
| Proved Undeveloped | 533 | 486 | 415 | 374 | — | — | 70 | 65 | 57 | 55 | 7 | 6 | 225 | 219 |
| Total Proved | 1,008 | 922 | 643 | 572 | — | — | 250 | 241 | 299 | 277 | 69 | 64 | 319 | 311 |
| Probable | 1,298 | 1,095 | 277 | 230 | 661 | 542 | 202 | 184 | 175 | 159 | 24 | 22 | 742 | 655 |
| Total Proved Plus Probable | 2,306 | 2,017 | 920 | 802 | 661 | 542 | 452 | 425 | 474 | 436 | 93 | 86 | 1,061 | 966 |

1 Other includes Yemen, Nigeria and Colombia.

At December 31, 2011, our proved plus probable reserves estimates were approximately 2.3 billion boe, of which about 1 billion boe are proved and 1.3 billion boe are probable.

Over 60% of our reserves relate to our Canadian oil sands properties. The synthetic oil reserves relate to our Long Lake and Kinosis K1A projects and our non-operated interest in Syncrude. These reserves reflect bitumen which is upgraded on site into synthetic oil and are expected to be developed and produced through the existing facilities over the next 50 years. The bitumen reserves relate to our Kinosis and Hangingstone properties, where we have not yet committed to building upgrading facilities at this time. Project planning at Kinosis and Hangingstone is underway.

Our oil sands reserves estimates and development plans are continually evolving to reflect production performance and other information. This year, as part of our reserves process, we revised our expectations of bitumen recoverability from our oil sands reservoirs. Our previous interpretation underestimated the productivity of thick clean sand, and overestimated the productivity of poorer quality sand and the effects of shale. As a result, in the high-quality areas, we increased the bitumen recovery factors. Conversely, we reduced our reserve estimates on the poor quality reservoir and removed proved acreage in lower quality areas that we are less likely to develop. This revised understanding of the reservoir productivity caused us to change our resource development strategy to fill the Long Lake upgrader. Our plans now include accelerating development of the Kinosis K1A lands, a subset of the original Kinosis lease, where extensive core hole testing indicates higher quality resource. These lands can be brought on stream sooner than other Long Lake areas as we are further advanced in the planning process.

In accordance with our reserves policy, we have our in situ oil sands properties evaluated by a third-party qualified reserves consultant, McDaniel & Associates Consultants Ltd. (McDaniel). They have extensive experience in estimating reserves for oil sands properties as they also regularly conduct evaluations for a significant number of other oil sands companies. Each year, McDaniel updates their estimates using all available technical, economic and company data including core, well, seismic, pressure and production data, our development plans, and experience they gain from evaluating other oil sands properties. McDaniel has generated proved and proved plus probable reserves estimates and revenue forecasts for each of our in situ oil sands properties from this information. McDaniel has provided an opinion that their independently-determined estimates are, in aggregate, within 10% of our estimates. We believe that the independent evaluation provides the highest level of scrutiny to our estimates as each estimate is based upon independent work and differs from an audit, which may not require the evaluator to independently generate detailed estimates that can be used for comparison.

The remainder of our reserves are widely distributed throughout our oil and gas properties around the world. Our light and medium oil reserves relate to our offshore oil and gas operations in the UK North Sea, US Gulf of Mexico, Nigeria, and onshore Colombia. Our natural gas reserves relate to our properties in the US Gulf of Mexico, UK North Sea, and southern Alberta. Our CBM reserves are located primarily in central Alberta and our shale gas reserves are located in the Horn River basin in northeast British Columbia.

All of our reserves estimates are subject to the same standard of rigor in their preparation and independent evaluation as our oil sands reserves. See the section entitled "Independent Reserves Evaluations" on pages 37 to 38 of this AIF.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

RECONCILIATION OF CHANGES IN RESERVES

The following table provides a reconciliation of Nexen's total proved, probable and proved plus probable reserves (before royalties) as at December 31, 2011 using forecast prices and costs.

GROSS RESERVES (NEXEN RESERVES BEFORE ROYALTIES)

| (Before Royalties) | Total (mmboe) | Canada Synthetic Oil Syncrude (mmbbls) | Canada Synthetic Oil In Situ (mmbbls) | Canada Bitumen2 In Situ (mmbbls) | Canada Natural Gas (bcf) | Canada CBM (bcf) | Canada Shale Gas (bcf) | United Kingdom Light and Medium Oil (mmbbls) | United Kingdom Natural Gas (bcf) | United States Light and Medium Oil (mmbbls) | United States Natural Gas (bcf) | Other1 Light and Medium Oil (mmbbls) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Proved Reserves | | | | | | | | | | | | |
| December 31, 2010 | 1,011 | 324 | 314 | — | 155 | 115 | 151 | 195 | 67 | 19 | 134 | 55 |
| Discoveries | 7 | — | — | — | — | — | 44 | — | — | — | — | — |
| Extensions and Improved Recovery | 121 | 8 | 94 | — | 9 | — | 94 | 1 | 7 | — | 1 | 1 |
| Technical Revisions | (53) | — | (84) | — | — | (25) | 40 | 26 | 4 | — | 2 | 1 |
| Economic Factors | (2) | — | — | — | (20) | (6) | 4 | 1 | (2) | — | 1 | — |
| Production | (76) | (8) | (5) | — | (16) | (15) | (14) | (32) | (11) | (3) | (32) | (14) |
| December 31, 2011 | 1,008 | 324 | 319 | — | 128 | 69 | 319 | 191 | 65 | 16 | 106 | 43 |
| Total Probable Reserves | | | | | | | | | | | | |
| December 31, 2010 | 1,123 | 46 | 882 | — | 44 | 32 | 33 | 106 | 59 | 7 | 80 | 41 |
| Discoveries | 145 | — | — | 49 | — | — | 165 | 3 | 1 | 58 | 37 | — |
| Extensions and Improved Recovery | 97 | 8 | — | — | 1 | — | 500 | — | — | 1 | 5 | 4 |
| Technical Revisions | 32 | — | 27 | — | (16) | (3) | 28 | 11 | (6) | — | (9) | (4) |
| Conversions3 | (130) | (8) | (94) | — | (1) | — | — | (21) | (12) | (1) | (12) | (2) |
| Economic Factors | (64) | — | (67) | — | 5 | (5) | 16 | (1) | (1) | — | — | — |
| Reclassification to Bitumen4 | 95 | — | (517) | 612 | — | — | — | — | — | — | — | — |
| December 31, 2011 | 1,298 | 46 | 231 | 661 | 33 | 24 | 742 | 98 | 41 | 65 | 101 | 39 |
| Total Proved Plus Probable Reserves | | | | | | | | | | | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| December 31, 2010 | 2,134 | 370 | 1,196 | — | 199 | 147 | 184 | 301 | 126 | 26 | 214 | 96 |
| Discoveries | 152 | — | — | 49 | — | — | 209 | 3 | 1 | 58 | 37 | — |
| Extensions and Improved Recovery | 218 | 16 | 94 | — | 10 | — | 594 | 1 | 7 | 1 | 6 | 5 |
| Technical Revisions | (21) | — | (57) | — | (16) | (28) | 68 | 37 | (2) | — | (7) | (3) |
| Conversions3 | (130) | (8) | (94) | — | (1) | — | — | (21) | (12) | (1) | (12) | (2) |
| Economic Factors | (66) | — | (67) | — | (15) | (11) | 20 | — | (3) | — | 1 | — |
| Reclassification to Bitumen4 | 95 | — | (517) | 612 | — | — | — | — | — | — | — | — |
| Production | (76) | (8) | (5) | — | (16) | (15) | (14) | (32) | (11) | (3) | (32) | (14) |
| December 31, 2011 | 2,306 | 370 | 550 | 661 | 161 | 93 | 1,061 | 289 | 106 | 81 | 207 | 82 |

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1 Other includes Yemen, Nigeria and Colombia.
2 Includes reserves for which there are no definitive plans for upgrading at this time.
3 Technical revisions.
4 Economic factors.

PROVED RESERVES

During the year, proved reserves decreased by 3 mmboe as our net additions of 73 mmboe were slightly less than production.

Discoveries of 7 mmboe at Horn River were due to the recognition of shale gas reserves in an additional shale gas zone.

Extensions and improved recovery of 121 mmboe were primarily due to recognizing Kinosis K1A reserves that are now being dedicated to the Long Lake upgrader and recognition of shale gas reserves for an 18-well Horn River pad that we expect to drill. The extensions of 94 mmboe at Kinosis K1A are included in our proved synthetic oil reserves as we are developing the area to feed the Long Lake upgrader. The remaining Kinosis lands are expected to be developed using SAGD well pairs to provide bitumen sales as we have not committed to build upgrading facilities at this time.

Technical revisions resulted in a 53 mmboe net reduction, which primarily relate to changes in our Long Lake expectations. These were partially offset by positive performance at Buzzard, Telford and Ettrick in the UK North Sea, and at our Horn River shale gas development. The 84 mmboe reduction of Long Lake synthetic oil reserves was the result of our re-assessment of the resource on the Long Lake lease which reflects a net reduction in recoverable oil in some areas. It also reflects a downgrade of proved reserves that will be deferred by a change in our development plans to dedicate Kinosis K1A to the Long Lake project. The Kinosis K1A reserves have priority since they can be brought on stream faster.

Economic factors primarily reflect lower future gas prices.

PROBABLE RESERVES

During the year, our probable reserves increased by 175 mmboe. This is due to additions of 274 mmboe, which includes our Appomattox discovery, recognition of our Hangingstone bitumen property, extensions at the Horn River shale gas properties, and 95 mmboe from reclassifying synthetic oil reserves at Kinosis to bitumen reserves. This was partially offset by reductions of 64 mmboe due to negative economic factors and conversions of 130 mmboe to proved reserves.

Discoveries of 145 mmboe include recognition of probable reserves for successes in the south fault block on our Appomattox discovery in the US Gulf of Mexico, our Hangingstone non-operated oil sands property where we are advancing plans to construct a 174-well SAGD development, the Solitaire property in the UK North Sea and recognizing shale gas reserves in a lower shale gas zone in the Horn River wells.

Extensions and improved recoveries of 97 mmboe primarily relate to additional drilling at Horn River, which is expected over the next five years.

Technical revisions resulted in a 32 mmboe increase primarily related to Long Lake, Kinosis and Horn River. Increases at Long Lake reflect the re-assessment of the resource and the reclassification of some proved reserves to probable reserves. Increases at Kinosis are a result of the re-evaluation of bitumen in place and recovery factors. Horn River reflects positive production performance supporting increased expected recoveries. Reductions are largely due to lower performance on our Canadian gas and CBM properties.

Conversions reflect probable reserves that were converted to proved reserves as a result of increased expectations of producing the reserves based on advancement of development plans, production performance and drilling results. The largest change reflects the acceleration of the Kinosis K1A area development.

Economic factors relate to changes in timing of our development plans at Long Lake and limiting the reserves to a 50-year production period and net royalty increases due to changes in price and operating costs.

Synthetic oil probable reserves reflect the reclassification of synthetic oil to bitumen as a result of our expectations regarding future development plans for Kinosis. Currently, we do not have sufficient certainty as to when we will build upgrading facilities at Kinosis and therefore, are required to classify the reserves as bitumen.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

## UNDEVELOPED RESERVES

The following table discloses volumes of proved undeveloped and probable undeveloped reserves that were first attributed in the last two years.

| | Proved Undeveloped (Before Royalties) | | | | Probable Undeveloped (Before Royalties) | | | |
|---|---|---|---|---|---|---|---|---|
| | 2010[1] | | 2011 | | 2010[1] | | 2011 | |
| | First Attributed | Booked at Year-End | First Attributed | Booked at Year-End | First Attributed | Booked at Year-End | First Attributed | Booked at Year-End |
| Synthetic Oil—In Situ (mmbbls) | 3 | 266 | 93 | 284 | — | 861 | — | 221 |
| Synthetic Oil—Syncrude (mmbbls) | 7 | 123 | 8 | 131 | 17 | 46 | 8 | 46 |
| Bitumen (mmbbls) | — | — | — | — | — | — | 49 | 661 |
| Light and Medium Oil (mmbbls) | 38 | 100 | 1 | 70 | 7 | 89 | 67 | 121 |
| Shale Gas (bcf) | 103 | 103 | 129 | 225 | 19 | 19 | 656 | 695 |
| Natural Gas (bcf) | 32 | 81 | 7 | 57 | 20 | 61 | 43 | 74 |
| CBM (bcf) | 12 | 13 | — | 7 | 3 | 3 | — | 2 |
| Total (mmboe) | 73 | 522 | 125 | 533 | 31 | 1,010 | 241 | 1,178 |

1 Reserves data is unavailable prior to 2010 when Nexen received an exemption from certain requirements of NI 51-101.

Approximately half of our proved reserves are undeveloped at December 31, 2011. More than 75% of these proved undeveloped reserves (PUDs) are located on our oil sands properties at Long Lake and Syncrude which will be developed as we need bitumen feedstock to supply the upgraders during their expected lives. Other PUDs relate to ongoing development activity in the UK North Sea at Buzzard, Golden Eagle, Rochelle and Telford, in Canada at our CBM and Horn River shale gas properties, and in the US Gulf of Mexico.

The in situ synthetic oil PUDs relate to reserves needed to supply the Long Lake upgrader over its expected life. They are expected to be converted to proved developed reserves over the next 28 years as we drill additional SAGD wells at Long Lake and Kinosis K1A to offset declines from the initial wells. These wells were part of the initial field development plan and included in the project investment decision. The Syncrude synthetic oil PUDs relate to Syncrude's Aurora South mine. The mine is included in the Syncrude development plan and was contemplated in the project investment decision relating to the Stage 3 expansion completed in 2005. We do not consider this mine to be developed as the extraction equipment required to access the reserves has not yet been moved to the mine site. We are proceeding with planning for the development of the mine and other mining leases and expect to commence construction in five to seven years. The Aurora South mine PUDs of 131 mmboe are expected to be converted to proved developed reserves in eight to ten years.

Our light and medium oil PUDs are primarily located in the UK North Sea, offshore West Africa, and the US Gulf of Mexico. In the UK North Sea, 45 mmboe of light and medium oil PUDs primarily relate to development projects underway at Golden Eagle and Rochelle, and ongoing development of the Buzzard, Ettrick and Blackbird fields. We have 20 mmboe of PUDs at our offshore West Africa properties, which are expected to be converted to proved developed reserves before the end of 2013 as additional facilities and development drilling is completed and tied into the production facilities that are currently being commissioned. The remaining PUDs are located in the US Gulf of Mexico.

Our shale gas PUDs are reserves related to planned development of additional pads at Horn River in northeast British Columbia, which are expected to be completed over the next two years.

Our natural gas PUDs are located in the UK North Sea and US Gulf of Mexico, and connected to our light and medium oil projects.

We expect to convert all of our PUDs to proved developed in the next four years except at Long Lake and Syncrude, which are expected to be converted to developed as required to keep the upgraders full for the next 35 years.

We expect our ongoing exploration and development activities will continue to add new PUDs.

The majority of our probable reserves are undeveloped and primarily reflects incremental synthetic oil reserves related to future drilling to keep the Long Lake upgrader full for 50 years, expected SAGD development of the bitumen resource at Kinosis, and extension of the plant life and expected higher future yields at Syncrude. These probable reserves will typically be developed in conjunction with proved reserves, but can take longer periods to develop. The remaining probable undeveloped reserves relate to ongoing pad development of Horn River, Appomattox in the Gulf of Mexico and discoveries offshore West Africa. We expect these remaining probable undeveloped reserves will be developed over the next seven years.

Our oil sands projects are large-scale developments with significantly longer production lives than conventional oil and gas projects. The proved and probable reserves associated with these projects are developed over a period of decades within the limits of facility capacity.

Net Present Value of Future Net Revenue

The estimates of future net revenues presented in the following tables do not represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material.

Future net revenue includes estimated future abandonment costs related to wells and production facilities required to produce the reserves which have been developed or are anticipated to be developed.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

NET PRESENT VALUE OF FUTURE NET REVENUE BEFORE INCOMETAXES
AS AT DECEMBER 31, 2011
Forecast Prices and Costs

| | Before IncomeTaxes Discounted at (%/year) (Cdn$ millions) | | | | | Unit Value Before Tax1 Discounted at 10% ($/boe) |
|---|---|---|---|---|---|---|
| | 0% | 5% | 10% | 15% | 20% | |
| Proved | | | | | | |
| Canada | | | | | | |
| Proved Developed Producing | 8,676 | 5,090 | 3,395 | 2,483 | 1,937 | 14.64 |
| Proved Developed Non-Producing | 306 | 254 | 206 | 166 | 134 | 19.86 |
| Proved Undeveloped | 14,753 | 4,702 | 1,464 | 213 | (348) | 3.56 |
| | 23,735 | 10,046 | 5,065 | 2,862 | 1,723 | 7.74 |
| United Kingdom | | | | | | |
| Proved Developed Producing | 10,213 | 8,951 | 7,981 | 7,226 | 6,626 | 54.47 |
| Proved Developed Non-Producing | 494 | 446 | 412 | 387 | 367 | 77.88 |
| Proved Undeveloped | 2,069 | 1,484 | 1,032 | 696 | 446 | 20.53 |
| | 12,776 | 10,881 | 9,425 | 8,309 | 7,439 | 46.64 |
| United States | | | | | | |
| Proved Developed Producing | (191) | (57) | 23 | 72 | 103 | 1.98 |
| Proved Developed Non-Producing | 519 | 400 | 318 | 258 | 214 | 30.07 |
| Proved Undeveloped | 395 | 301 | 234 | 186 | 150 | 31.04 |
| | 723 | 644 | 575 | 516 | 467 | 19.30 |
| Other2 | | | | | | |
| Proved Developed Producing | 189 | 173 | 159 | 147 | 137 | 39.43 |
| Proved Developed Non-Producing | 1,052 | 916 | 807 | 718 | 646 | 50.33 |
| Proved Undeveloped | 959 | 797 | 670 | 570 | 489 | 40.75 |
| | 2,200 | 1,886 | 1,636 | 1,435 | 1,272 | 44.81 |
| Total Company | | | | | | |
| Proved Developed Producing | 18,887 | 14,157 | 11,558 | 9,928 | 8,803 | 29.32 |
| Proved Developed Non-Producing | 2,371 | 2,016 | 1,743 | 1,529 | 1,361 | 41.22 |
| Proved Undeveloped | 18,176 | 7,284 | 3,400 | 1,665 | 737 | 7.00 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Total Proved | 39,434 | 23,457 | 16,701 | 13,122 | 10,901 | 18.10 |
| | | | | | | |
| Probable | | | | | | |
| Canada | 35,632 | 9,183 | 3,121 | 1,157 | 354 | 3.51 |
| United Kingdom | 8,811 | 6,652 | 5,250 | 4,292 | 3,602 | 50.35 |
| United States | 4,583 | 2,682 | 1,661 | 1,081 | 734 | 23.96 |
| Other2 | 1,681 | 1,268 | 993 | 805 | 674 | 32.14 |
| Total Probable | 50,707 | 19,785 | 11,025 | 7,335 | 5,364 | 10.07 |
| | | | | | | |
| Proved Plus Probable | | | | | | |
| Canada | 59,367 | 19,229 | 8,186 | 4,019 | 2,077 | 5.30 |
| United Kingdom | 21,587 | 17,533 | 14,675 | 12,601 | 11,041 | 47.90 |
| United States | 5,306 | 3,326 | 2,236 | 1,597 | 1,201 | 22.56 |
| Other2 | 3,881 | 3,154 | 2,629 | 2,240 | 1,946 | 39.01 |
| Total Proved Plus Probable | 90,141 | 43,242 | 27,726 | 20,457 | 16,265 | 13.74 |

1 The unit values are based on net reserve volumes.

2 Represents reserves in Yemen, Nigeria and Colombia.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

NET PRESENT VALUE OF FUTURE NET REVENUE AFTER INCOME TAXES
AS AT DECEMBER 31, 2011
Forecast Prices and Costs

| | After Income Taxes Discounted at (%/year)1 (Cdn$ millions) | | | | |
|---|---|---|---|---|---|
| | 0% | 5% | 10% | 15% | 20% |
| Proved | | | | | |
| Canada | | | | | |
| Proved Developed Producing | 8,676 | 5,089 | 3,394 | 2,482 | 1,937 |
| Proved Developed Non-Producing | 306 | 258 | 212 | 171 | 138 |
| Proved Undeveloped | 11,081 | 3,554 | 1,055 | 48 | (424) |
| | 20,063 | 8,901 | 4,661 | 2,701 | 1,651 |
| United Kingdom | | | | | |
| Proved Developed Producing | 3,649 | 3,359 | 3,056 | 2,794 | 2,576 |
| Proved Developed Non-Producing | 195 | 177 | 164 | 154 | 146 |
| Proved Undeveloped | 730 | 546 | 382 | 255 | 159 |
| | 4,574 | 4,082 | 3,602 | 3,203 | 2,881 |
| United States | | | | | |
| Proved Developed Producing | (191) | (57) | 23 | 72 | 103 |
| Proved Developed Non-Producing | 519 | 400 | 318 | 258 | 214 |
| Proved Undeveloped | 395 | 301 | 234 | 186 | 150 |
| | 723 | 644 | 575 | 516 | 467 |
| Other2 | | | | | |
| Proved Developed Producing | 136 | 125 | 115 | 107 | 99 |
| Proved Developed Non-Producing | 1,053 | 917 | 807 | 718 | 647 |
| Proved Undeveloped | 959 | 797 | 671 | 570 | 489 |
| | 2,148 | 1,839 | 1,593 | 1,395 | 1,235 |
| Total | | | | | |
| Proved Developed Producing | 12,270 | 8,516 | 6,588 | 5,455 | 4,715 |
| Proved Developed Non-Producing | 2,073 | 1,752 | 1,501 | 1,301 | 1,145 |
| Proved Undeveloped | 13,165 | 5,198 | 2,342 | 1,059 | 374 |
| Total Proved | 27,508 | 15,466 | 10,431 | 7,815 | 6,234 |
| | | | | | |
| Probable | | | | | |
| Canada | 26,365 | 6,743 | 2,230 | 759 | 154 |
| United Kingdom | 3,311 | 2,551 | 2,015 | 1,644 | 1,377 |
| United States | 3,100 | 1,844 | 1,157 | 762 | 524 |
| Other2 | 1,596 | 1,210 | 952 | 775 | 650 |
| Total Probable | 34,372 | 12,348 | 6,354 | 3,940 | 2,705 |
| | | | | | |
| Proved Plus Probable | | | | | |
| Canada | 46,428 | 15,644 | 6,891 | 3,460 | 1,805 |
| United Kingdom | 7,885 | 6,633 | 5,617 | 4,847 | 4,258 |
| United States | 3,823 | 2,488 | 1,732 | 1,278 | 991 |

| | | | | | |
|---|---|---|---|---|---|
| Other2 | 3,744 | 3,049 | 2,545 | 2,170 | 1,885 |
| Total Proved Plus Probable | 61,880 | 27,814 | 16,785 | 11,755 | 8,939 |

1 We have estimated the after-tax net present value after including the existing tax positions at a corporate level of aggregation. As a result, our after tax economics are not estimated on a project stand-alone basis and therefore the valuation of individual properties on a stand-alone basis may differ significantly from our estimates. We also have not included costs related to corporate activities such as financing and corporate G&A associated with administration and planning activities.

2 Represents reserves in Yemen, Nigeria and Colombia.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS AT DECEMBER 31, 2011
Forecast Prices and Costs

| (Cdn$ millions) | Revenue | Royalties | Operating Costs | Development Costs | Abandonment and Reclamation Costs | Future Net Revenue Before Income Taxes | Income Taxes | Future Net Revenue After Income Taxes |
|---|---|---|---|---|---|---|---|---|
| Proved Reserves | | | | | | | | |
| Canada | 88,157 | 9,962 | 46,392 | 7,177 | 891 | 23,735 | 3,672 | 20,063 |
| United Kingdom | 21,073 | 18 | 5,173 | 1,608 | 1,498 | 12,776 | 8,202 | 4,574 |
| United States | 2,179 | 248 | 419 | 210 | 579 | 723 | — | 723 |
| Other1 | 4,361 | 624 | 845 | 552 | 140 | 2,200 | 52 | 2,148 |
| Total | 115,770 | 10,852 | 52,829 | 9,547 | 3,108 | 39,434 | 11,926 | 27,508 |
| Proved Plus Probable Reserves | | | | | | | | |
| Canada | 214,026 | 31,928 | 98,656 | 22,496 | 1,579 | 59,367 | 12,939 | 46,428 |
| United Kingdom | 32,244 | 43 | 7,159 | 1,825 | 1,630 | 21,587 | 13,702 | 7,885 |
| United States | 10,421 | 1,540 | 1,181 | 1,634 | 760 | 5,306 | 1,483 | 3,823 |
| Other1 | 8,448 | 1,504 | 1,306 | 1,518 | 239 | 3,881 | 137 | 3,744 |
| Total | 265,139 | 35,015 | 108,302 | 27,473 | 4,208 | 90,141 | 28,261 | 61,880 |

1 Represents reserves in Yemen, Nigeria and Colombia.

TOTAL FUTURE NET REVENUE BY PRODUCT GROUP AS AT DECEMBER 31, 2011
Forecast Prices and Costs

| | Future Net Revenue Before Income Taxes (discounted at 10%/year) (Cdn$ millions) | Unit Value Before Income Taxes1 (discounted at 10%/year) ($/bbl) | ($/mcf) |
|---|---|---|---|
| Proved Reserves | | | |
| Light and Medium Oil2 | 11,673 | 46.16 | — |
| Synthetic Oil | 4,899 | 8.57 | — |
| Natural Gas | 46 | — | 0.22 |
| CBM | 59 | — | 0.93 |
| Shale Gas | 24 | — | 0.08 |
| Proved Plus Probable Reserves | | | |
| Light and Medium Oil2 | 19,596 | 44.25 | — |
| Synthetic Oil | 6,848 | 8.54 | — |

| | | | |
|---|---|---|---|
| Bitumen | 700 | 12.63 | — |
| Natural Gas | 77 | — | 0.23 |
| CBM | 93 | — | 1.09 |
| Shale Gas | 412 | — | 0.43 |

1 Unit values are based upon net reserves volumes.
2 Including solution gas and other by-products.

FORECAST PRICES AND COSTS USED IN ESTIMATES

NI 51-101 requires that the forecast prices and costs used in preparation of the reserves estimates represent a reasonable outlook of the future. The pricing and cost assumptions were determined with reference to benchmark and inflationary forecasts obtained from a number of qualified reserves evaluation firms and other information sources. Field pricing was estimated by applying typical adjustments such as quality and transportation costs to a benchmark price.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

The forecast cost and price assumptions used in the reserve estimates are summarized in the following tables:

PRICING AND INFLATION RATE ASSUMPTIONS AS AT DECEMBER 31, 2011
Forecast Prices and Costs

| | Light and Medium Oil | | | Synthetic Crude Oil | Natural Gas | | | Inflation Rates | Exchange Rate |
|---|---|---|---|---|---|---|---|---|---|
| Year | WTI Cushing Oklahoma (US$/bbl) | Brent (US$/bbl) | Vasconia (US$/bbl) | MSW Edmonton (Cdn$/bbl) | Henry Hub Gas Price (US$/mmbtu) | National Balancing Pt (£/therm) | AECO Gas Price (Cdn$/GJ) | %/Year | (US$/Cdn$) |
| Historical | | | | | | | | | |
| 2011 | 95.26 | 111.38 | 107.65 | 96.78 | 4.05 | 0.56 | 3.47 | n/a | 1.02 |
| Forecast | | | | | | | | | |
| 2012 | 95 | 105 | 102 | 97 | 4.15 | 0.62 | 3.50 | 2.0 | 0.95 |
| 2013 | 95 | 105 | 97 | 94 | 4.70 | 0.66 | 4.00 | 2.0 | 1.00 |
| 2014 | 95 | 100 | 94 | 94 | 5.25 | 0.69 | 4.50 | 2.0 | 1.00 |
| 2015 | 100 | 100 | 95 | 96 | 5.80 | 0.69 | 5.00 | 2.0 | 1.00 |
| 2016 | 100 | 100 | 97 | 99 | 6.25 | 0.69 | 5.40 | 2.0 | 1.00 |
| Thereafter | 2% infl. | 2% infl. | 2% infl. | 2% infl. | 2% infl. | 2% infl. | 2% infl. | 2% infl. | 1.00 |

The forecast price and cost assumptions assume the continuance of current laws and regulations. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. These assumptions may differ from internal assumptions that are used for project economics and planning purposes.

Weighted average realized prices for the year ended December 31, 2011 are summarized in the section entitled Production History on pages 36 to 37.

SUMMARY OF OIL AND GAS FUTURE DEVELOPMENT COSTS AS AT DECEMBER 31, 2011
Forecast Prices and Costs

| | Total Proved Reserves | | | | | Total Proved Plus Probable Reserves | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Cdn$ millions | Canada | United Kingdom | United States | Other | Total | Canada | United Kingdom | United States | Other | Total |
| 2012 | 860 | 714 | 50 | 384 | 2,008 | 914 | 793 | 73 | 384 | 2,164 |
| 2013 | 815 | 406 | 22 | 126 | 1,369 | 1,078 | 481 | 38 | 126 | 1,723 |
| 2014 | 328 | 303 | 68 | 39 | 738 | 1,159 | 339 | 197 | 194 | 1,889 |
| 2015 | 201 | 141 | 35 | 3 | 380 | 1,104 | 169 | 218 | 318 | 1,809 |
| 2016 | 127 | 44 | 20 | — | 191 | 601 | 43 | 222 | 361 | 1,227 |
| Thereafter | 4,846 | — | 15 | — | 4,861 | 17,640 | — | 886 | 135 | 18,661 |
| Total (undiscounted) | 7,177 | 1,608 | 210 | 552 | 9,547 | 22,496 | 1,825 | 1,634 | 1,518 | 27,473 |

We believe internally generated cash flow from operations, supplemented if required by existing credit facilities, access to debt and equity markets, and future asset dispositions, are sufficient to fund future growth plans. There can be no guarantee that funds will be available in the future or that we will allocate funding to develop all of the reserves.

Failure to develop those reserves would have a negative impact on future production and cash flow and could result in negative revisions to our reserves.

Interest and other costs of external funding requirements are not included in the future net revenue estimates. Since our investment decisions are based on expected returns on investment, interest or other funding costs do not directly affect the reserves estimates. We do not expect that interest or other costs of external funding would make the development of any property uneconomic.

# APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

Other Oil and Gas Information
PRODUCING AND NON-PRODUCING WELLS

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2011.

| | Oil | | Gas | | Total | |
|---|---|---|---|---|---|---|
| (number of wells) | Gross | Net | Gross | Net | Gross | Net |
| Producing Wells | | | | | | |
| United Kingdom | 63 | 31 | — | — | 63 | 31 |
| Canada—Alberta | 17 | 6 | 1,470 | 1,242 | 1,487 | 1,248 |
| Canada—British Columbia | — | — | 27 | 27 | 27 | 27 |
| Canada—Saskatchewan | — | — | 1,322 | 1,259 | 1,322 | 1,259 |
| Canada—Oil Sands | 90 | 58 | — | — | 90 | 58 |
| US—Alabama | 12 | — | 6 | — | 18 | — |
| US—Louisiana | 51 | 40 | 50 | 40 | 101 | 80 |
| US—Texas | 15 | 3 | 9 | 2 | 24 | 5 |
| Yemen | 56 | 56 | — | — | 56 | 56 |
| Colombia | 111 | 11 | — | — | 111 | 11 |
| Total | 415 | 205 | 2,884 | 2,570 | 3,299 | 2,775 |
| Non-Producing Wells | | | | | | |
| United Kingdom | 15 | 8 | — | — | 15 | 8 |
| Canada—Alberta | 2 | 2 | 295 | 172 | 297 | 174 |
| Canada—British Columbia | — | — | 22 | 22 | 22 | 22 |
| Canada—Saskatchewan | 1 | 1 | 9 | 7 | 10 | 8 |
| Canada—Oil Sands | 18 | 12 | 21 | 14 | 39 | 26 |
| US—Alabama | 11 | — | 2 | — | 13 | — |
| US—Louisiana | 49 | 34 | 63 | 64 | 112 | 98 |
| US—Texas | 19 | 1 | 33 | 2 | 52 | 3 |
| Yemen | 48 | 48 | 1 | 1 | 49 | 49 |
| Nigeria | 25 | 5 | — | — | 25 | 5 |
| Total | 188 | 111 | 446 | 282 | 634 | 393 |

PROPERTIES WITH NO ATTRIBUTED RESERVES

The following table sets out the unproved properties in which we have an interest for which we have no attributed reserves, as at December 31, 2011.

| (thousands of acres) | Gross | Net | To Expire Within One Year1 |
|---|---|---|---|
| United Kingdom | 1,579 | 971 | 25 |
| Canada | 1,806 | 997 | 197 |
| United States | 1,206 | 564 | 77 |
| Yemen2 | 511 | 511 | — |
| Colombia3 | 1,617 | 1,531 | — |

| | | | |
|---|---|---|---|
| Nigeria2,4 | 230 | 41 | — |
| Poland | 2,258 | 903 | — |
| Norway | 188 | 90 | — |
| Total | 9,395 | 5,608 | 299 |

---

1 Net acres of unproved properties for which we expect our rights to explore, develop and exploit to expire within one year.
2 The acreage is covered by production-sharing contracts.
3 The acreage is covered by an association contract.
4 The acreage is covered by joint venture agreements.

Our properties with no attributed reserves are geographically and technically diverse and require a variety of capital investment activities ranging from seismic acquisition to drilling and development in order to explore and potentially prove-up reserves. Some properties are in the early evaluation stages of exploration while others have discovered hydrocarbons. Our property portfolio is continuously reviewed on the basis of prospectivity, risk, and economics to prioritize the opportunities we choose to invest in and develop. As a result, some properties are prioritized for capital investment, while others are held as inactive pending the results of future reviews, or sold, traded, relinquished, or allowed to expire.

The practice of requiring companies to pledge to carry out work commitments such as seismic acquisition, geophysical studies or exploration drilling in exchange for property exploration and development rights is common particularly in undeveloped or unexplored areas. We estimate work commitments of about $100 million to retain the related properties located in offshore UK, offshore Nigeria and Poland over the next three years. We continue to assess, and if warranted, explore these lands prior to their expiry. There are no significant factors or uncertainties associated with the economic viability and development of these properties other than those discussed generally in the “Risk Factors” section on page 44 to 51 of this AIF.

## ADDITIONAL INFORMATION CONCERNING ABANDONMENT AND RECLAMATION COSTS

We are required to remove or remedy the effect of our activities at our present and future operating sites by dismantling and removing production facilities and remediating the related damage. In estimating our future abandonment and reclamation costs (A&R costs), we make estimates and judgments on activities that will occur many years from now. In estimating A&R costs, we consider many factors including existing contracts, regulations, A&R techniques, industry conditions and past experience. As such, factors are constantly changing and our estimates are uncertain.

As of December 31, 2011, our expected undiscounted A&R costs are $3,108 million ($1,038 million, discounted at 10%) for proved reserves, including $159 million of costs to be incurred within the next three financial years. These costs relate to approximately 3,168 existing net wells and additional wells planned to be drilled in the future to access proved reserves.

The total amount of A&R costs in our proved reserves estimate is higher than the asset retirement obligation on our balance sheet primarily due to retirement costs related to planned future capital expenditures. These future obligations are relevant for determining the economic viability of our reserves but do not constitute an existing liability in our financial statements as the wells or facilities potentially giving rise to these costs have not yet been constructed.

## TAX HORIZON

We are currently cash taxable in the UK, Colombia and Yemen. In Canada, the US and Nigeria, our estimated tax horizon is beyond five years.

## COSTS INCURRED

The following table summarizes the costs incurred in our oil and gas activities for the year ended December 31, 2011.

| | Oil and Gas |
|---|---|

| (Cdn$ millions) | Total Oil and Gas | Canada | United Kingdom | United States | Other1 |
|---|---|---|---|---|---|
| Year Ended December 31, 2011 | | | | | |
| Property Acquisition Costs | | | | | |
| Proved | — | — | — | — | — |
| Unproved | 17 | 3 | 12 | 2 | — |
| Exploration Costs | 902 | 505 | 87 | 154 | 156 |
| Development Costs | 2,123 | 656 | 644 | 229 | 594 |
| Total Costs Incurred 2 | 3,042 | 1,164 | 743 | 385 | 750 |

1 Represents costs incurred in Yemen, Nigeria, Norway, Poland and Colombia.

2 Total costs incurred include asset retirement costs of $526 million and excludes costs related to chemicals, energy marketing, corporate and other of $59 million.

# APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

## EXPLORATION AND DEVELOPMENT ACTIVITIES

The following table sets forth the gross and net exploratory and development wells that were completed during 2011.

| | Exploratory Wells | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Oil Wells | | Gas Wells | | Service Wells1 | | Stratigraphic Wells | | Dry Holes | | Total | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| United Kingdom | — | — | — | — | — | — | — | — | 5.0 | 3.9 | 5.0 | 3.9 |
| Canada | 3.0 | 3.0 | 10.0 | 10.0 | — | — | — | — | — | — | 13.0 | 13.0 |
| United States | — | — | — | — | — | — | — | — | — | — | — | — |
| Other2 | — | — | — | — | — | — | — | — | 1.0 | 0.5 | 1.0 | 0.5 |
| Total | 3.0 | 3.0 | 10.0 | 10.0 | — | — | — | — | 6.0 | 4.4 | 19.0 | 17.4 |

| | Development Wells | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Oil Wells | | Gas Wells | | Service Wells1 | | Stratigraphic Wells | | Dry Holes | | Total | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| United Kingdom | 4.0 | 1.7 | — | — | — | — | — | — | 2.0 | 0.9 | 6.0 | 2.6 |
| Canada | 18.0 | 11.7 | 33.0 | 16.8 | 47.0 | 30.1 | 142.0 | 75.9 | — | — | 240.0 | 134.6 |
| United States | — | — | — | — | — | — | — | — | — | — | — | — |
| Other2 | 8.0 | 5.6 | — | — | 1.0 | 0.2 | — | — | — | — | 9.0 | 5.8 |
| Total | 30.0 | 19.0 | 33.0 | 16.8 | 48.0 | 30.3 | 142.0 | 75.9 | 2.0 | 0.9 | 255.0 | 143.0 |

| | Total Wells | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Oil Wells | | Gas Wells | | Service Wells1 | | Stratigraphic Wells | | Dry Holes | | Total | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| United Kingdom | 4.0 | 1.7 | — | — | — | — | — | — | 7.0 | 4.8 | 11.0 | 6.5 |
| Canada | 21.0 | 14.7 | 43.0 | 26.8 | 47.0 | 30.1 | 142.0 | 75.9 | — | — | 253.0 | 147.6 |
| United States | — | — | — | — | — | — | — | — | — | — | — | — |
| Other2 | 8.0 | 5.6 | — | — | 1.0 | 0.2 | — | — | 1.0 | 0.5 | 10.0 | 6.3 |
| Total | 33.0 | 22.0 | 43.0 | 26.8 | 48.0 | 30.3 | 142.0 | 75.9 | 8.0 | 5.3 | 274.0 | 160.4 |

---

1 Service wells include injector wells, waste water wells and other wells not intended to produce oil and gas.
2 Represents activity in Yemen, Nigeria, Norway and Colombia.

## PRODUCTION ESTIMATES

The following table sets out our estimated production for 2012 from our estimates of gross proved reserves and gross probable reserves.

| | Total | Synthetic Oil | Light and Medium Oil | Natural Gas | CBM | Shale Gas |
|---|---|---|---|---|---|---|

| | (mmboe) | (mmbbls) | | (mmbbls) | | | | (bcf) | | | (bcf) | (bcf) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (Before Royalties) | Company | Canada | United Kingdom | United States | Other1 | Total | Canada | United Kingdom | United States | Total | Canada | Canada |
| Total Proved | 72 | 13 | 33 | 3 | 8 | 44 | 16 | 13 | 22 | 51 | 12 | 21 |
| Total Probable | 8 | 1 | 3 | — | 3 | 6 | — | 4 | 5 | 9 | 1 | - |
| Total Proved Plus Probable | 80 | 14 | 36 | 3 | 11 | 50 | 16 | 17 | 27 | 60 | 13 | 21 |

1 Represents production in Yemen and Colombia.

Our Buzzard field in the UK is the only field which accounts for more than 20% of our estimated 2012 production volumes. Our reserves analysis estimates the field will produce 27 mmboe of primarily light and medium oil on a proved plus probable basis for the year ended December 31, 2012.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

PRODUCTION HISTORY

The following table summarizes certain information in respect of our production, prices received, royalties paid, production costs and resulting netback for the year ended December 31, 2011.

| Cash Netback1 | Quarters—2011 | | | | Total Year |
|---|---|---|---|---|---|
| (Cdn$, unless noted) | 1st | 2nd | 3rd | 4th | 2011 |
| United Kingdom | | | | | |
| Crude Oil: | | | | | |
| Sales (mbbls/d) | 104.2 | 73.3 | 75.2 | 92.7 | 86.3 |
| Price Received ($/bbl) | 99.97 | 110.67 | 107.58 | 110.46 | 106.76 |
| Natural Gas: | | | | | |
| Sales (mmcf/d) | 36 | 37 | 26 | 22 | 30 |
| Price Received ($/mcf) | 7.29 | 8.20 | 7.28 | 6.52 | 7.42 |
| Total Sales Volume (mmboe/d) | 110.2 | 79.5 | 79.5 | 96.4 | 91.3 |
| Price Received ($/boe) | 96.91 | 105.87 | 104.13 | 107.70 | 103.32 |
| Royalties and Other ($/boe) | — | 0.11 | 0.82 | 0.54 | 0.36 |
| Operating Costs ($/boe) | 9.85 | 8.48 | 14.46 | 9.99 | 10.60 |
| In-country Taxes ($/boe) | 42.46 | 42.76 | 41.00 | 43.24 | 42.41 |
| Netback ($/boe) | 44.60 | 54.52 | 47.85 | 53.93 | 49.95 |
| Canada—Natural Gas | | | | | |
| Sales (mmcf/d) | 97 | 85 | 79 | 112 | 93 |
| Price Received ($/mcf) | 3.65 | 3.62 | 3.51 | 3.08 | 3.44 |
| Royalties and Other ($/mcf) | 0.28 | 0.24 | 0.27 | 0.17 | 0.23 |
| Operating Costs ($/mcf) | 1.70 | 1.54 | 1.65 | 1.70 | 1.65 |
| Netback 2 ($/mcf) | 1.67 | 1.84 | 1.59 | 1.21 | 1.56 |
| Canada—Oil Sands In Situ3 | | | | | |
| Sales (mbbls/d) | 12.9 | 14.3 | 11.8 | 16.7 | 13.9 |
| Price Received ($/bbl) | 89.82 | 108.78 | 94.15 | 97.28 | 98.33 |
| Royalties and Other ($/bbl) | 3.58 | 6.05 | 5.07 | 5.29 | 5.05 |
| Operating Costs ($/bbl) | 89.43 | 95.34 | 85.42 | 67.41 | 83.44 |
| Netback ($/bbl) | (3.19) | 7.39 | 3.66 | 24.58 | 9.84 |
| Canada—Oil Sands Syncrude | | | | | |
| Sales (mbbls/d) | 23.2 | 20.4 | 21.6 | 18.2 | 20.8 |
| Price Received ($/bbl) | 94.60 | 111.79 | 97.65 | 104.32 | 101.73 |
| Royalties and Other ($/bbl) | 4.30 | 13.82 | 4.65 | 10.59 | 8.10 |
| Operating Costs ($/bbl) | 36.11 | 39.98 | 37.10 | 38.24 | 37.78 |
| Netback 2 ($/bbl) | 54.19 | 57.99 | 55.90 | 55.49 | 55.85 |

1 Netbacks are defined as average sales price less royalties and other, operating costs, and in-country taxes in Yemen. The unit values are based on gross reserve volumes.

2 Average sales price, royalties, and operating costs for Canadian CBM and shale gas are included in Canada—Natural Gas.

3

Excludes activities related to third-party bitumen purchased, processed and sold. Sales volumes and amounts relate to PSCTM sales made to third parties during the period.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

| Cash Netback1 | | Quarters—2011 | | | Total Year |
|---|---|---|---|---|---|
| (Cdn$, unless noted) | 1st | 2nd | 3rd | 4th | 2011 |
| United States | | | | | |
| Crude Oil: | | | | | |
| Sales (mbbls/d) | 9.2 | 8.9 | 7.7 | 7.2 | 8.2 |
| Price Received ($/bbl) | 91.39 | 101.89 | 96.00 | 110.89 | 99.65 |
| Natural Gas: | | | | | |
| Sales (mmcf/d) | 103 | 96 | 81 | 66 | 86 |
| Price Received ($/mcf) | 4.36 | 4.42 | 4.27 | 3.59 | 4.21 |
| Total Sales Volume (mboe/d) | 26.3 | 24.9 | 21.2 | 18.2 | 22.6 |
| Price Received ($/boe) | 48.91 | 53.56 | 50.72 | 57.27 | 52.31 |
| Royalties and Other ($/boe) | 5.65 | 6.11 | 5.63 | 3.31 | 5.30 |
| Operating Costs ($/boe) | 10.43 | 10.72 | 11.18 | 16.73 | 11.96 |
| Netback ($/boe) | 32.83 | 36.73 | 33.91 | 37.23 | 35.05 |
| Yemen | | | | | |
| Sales (mbbls/d) | 34.9 | 39.3 | 31.8 | 27.8 | 33.4 |
| Price Received ($/bbl) | 101.57 | 111.77 | 107.98 | 111.14 | 108.11 |
| Royalties and Other ($/bbl) | 46.98 | 52.26 | 49.72 | 45.94 | 48.97 |
| Operating Costs ($/bbl) | 10.75 | 9.18 | 13.20 | 20.48 | 12.92 |
| In-country Taxes ($/bbl) | 13.48 | 16.26 | 15.49 | 14.03 | 14.89 |
| Netback ($/bbl) | 30.36 | 34.07 | 29.57 | 30.69 | 31.33 |
| Other Countries | | | | | |
| Sales (mbbls/d) | 1.8 | 1.7 | 1.6 | 1.6 | 1.7 |
| Price Received ($/bbl) | 93.52 | 106.57 | 101.28 | 110.46 | 102.71 |
| Royalties and Other ($/bbl) | 6.22 | 6.93 | 6.57 | 7.03 | 6.68 |
| Operating Costs ($/bbl) | 8.11 | 10.19 | 8.58 | 9.65 | 9.11 |
| Netback ($/mcf) | 79.19 | 89.45 | 86.13 | 93.78 | 86.92 |
| Company-Wide | | | | | |
| Oil and Gas Sales (mboe/d) | 225.5 | 194.3 | 180.7 | 197.6 | 199.2 |
| Price Received ($/boe) | 85.98 | 95.31 | 91.06 | 94.11 | 91.46 |
| Royalties and Other ($/boe) | 8.74 | 13.47 | 10.83 | 8.62 | 10.34 |
| Operating and Other Costs ($/boe) | 17.32 | 18.68 | 20.80 | 19.56 | 19.00 |
| In-countryTaxes ($/boe) | 22.84 | 20.78 | 20.76 | 23.08 | 21.92 |
| Netback ($/boe) | 37.08 | 42.38 | 38.67 | 42.85 | 40.20 |

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1 Netbacks are defined as average sales price less royalties and other, operating costs, and in-country taxes in Yemen. The unit values are based on gross reserve volumes.

INDEPENDENT RESERVES EVALUATIONS

The following provides an overview of the nature and scope of the independent evaluations and audits that we have had performed on our reserves estimates. An independent evaluation is a process whereby we request a third-party engineering firm to prepare an estimate of our proved and probable reserves by assessing and interpreting all available data on a reservoir. An independent audit is a process whereby we request a third-party engineering firm to prepare an estimate of our reserves by reviewing our estimates, supporting working papers and other data as they feel is necessary. The primary difference is that an evaluator uses the reservoir data to prepare their own estimate, whereas an auditor reviews our work and estimate in preparing their estimate.

We have at least 80% of our NI 51-101 reserves estimates either evaluated or audited annually by independent qualified reserves consultants using applicable NI 51-101 requirements. Given that reserves estimates are based on numerous assumptions, interpretations and judgments, differences frequently arise between the estimates prepared by different qualified estimators. When the initial estimate of proved reserves on the portfolio of properties differs by greater than 10%, we work with the independent reserves consultant to reconcile the difference to within 10%. Estimates pertaining to individual properties within the portfolio may differ by more than 10%, either positively or negatively. We do not attempt to resolve each property to within 10% as it would be time and cost prohibitive given the number of wells in which we have an interest. We follow a similar process in connection with our probable reserves estimates whereby we reconcile any differences on a proved plus probable basis to be within 10%, and as such, probable reserves for individual properties within the portfolio may differ significantly.

In each case, we request their estimates to be prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with NI 51-101 requirements. Generally recognized methods for estimating reserves include volumetric calculations, material balance techniques, production and pressure decline curve analysis, analogy with similar reservoirs and reservoir simulation. The method or combination of methods used is based on their professional judgment and experience. In preparing their estimates, they obtain information from us with respect to property interests, production from such properties, current costs of operations, expected future development and abandonment costs, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data. They may rely on the information without independent verification. However, if in the course of their evaluation they question the validity or sufficiency of any information, we request that they not rely on such information until they satisfactorily resolve their questions or independently verify such information.

We do not place any limitations on the work to be performed. Upon completion of their work, the independent reserves consultant issues an opinion as to whether our estimates of the proved and probable reserves for that portfolio of properties is, in aggregate, reasonable relative to the criteria set forth in NI 51-101.

For our reserves estimates prepared in accordance with NI 51-101 requirements, we engaged three independent reserves consultants to evaluate or audit our properties:

- We engaged DeGolyer and MacNaughton (D&M) to evaluate 100% of our proved and proved plus probable reserves in the UK North Sea, Nigeria, and our Canadian shale gas properties. D&M provided an opinion that the proved and proved plus probable reserves for the reviewed properties are reasonable because, in aggregate, they are within 10% of their estimates.
- We engaged McDaniel & Associates Consultants Ltd. (McDaniel) to evaluate approximately 100% of our proved and our proved plus probable reserves for our in situ oil sands properties. McDaniel provided an opinion that the proved and proved plus probable reserves for the reviewed properties are reasonable because, in aggregate, they are within 10% of their estimates.
- We also engaged McDaniel to audit 100% of our proved and proved plus probable reserves for our Syncrude interest. McDaniel provided an opinion that the proved and proved plus probable reserves estimates for the Syncrude property are reasonable because they expect it would be within 10% of their own estimate were they to perform their own detailed evaluation of the property.
- We engaged Ryder Scott Company (Ryder Scott) to evaluate 94% of our proved and 97% of our proved plus probable US Gulf of Mexico properties. Ryder Scott provided an opinion that the proved and proved plus probable reserves for the reviewed properties are reasonable because, in aggregate, they are within 10% of their estimates.

In aggregate our independent reserves consultants evaluated or audited 96% of our proved and 98% of our proved plus probable reserves.

For each opinion, an opinion letter has been prepared, which summarizes the work undertaken, the assumptions, data, methods and procedures they used and concludes with their opinion. These reports have been filed on SEDAR at www.sedar.com.

DEFINITIONS

In the foregoing reserves discussion the following definitions and notes are applicable:

1. "Gross" means:

(a) in relation to our interest in production or reserves, our "company gross reserves", which are our working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest to us;

(b) in relation to wells, the total number of wells in which we have an interest; and

(c) in relation to properties, the total area of properties in which we have an interest.

2. "Net" means:

(a) in relation to our interest in production or reserves, our working interest (operating and non-operating) share after deduction of royalties obligations, plus our royalty interests in production or reserves;

(b) in relation to our interest in wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and

(c) in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest we owned.

The crude oil, natural gas liquids and natural gas reserves estimates presented in this Statement are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below:

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

3. Reserves Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on:

(a) analysis of drilling, geological, geophysical and engineering data;

(b) the use of established technology; and

(c) specified economic conditions, which are generally accepted as being reasonable.

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

(a) Proved reserves are those reserves that 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.

(b) 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.

Other criteria that must also be met for the classification of reserves are provided in the Canadian Oil and Gas Evaluation (COGE) Handbook.

4. Development and Production Status

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories.

(a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in and the date of resumption of production is unknown.

(b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

LEVELS OF CERTAINTY FOR REPORTED RESERVES

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates are prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

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Special Note to Investors

Investors should note the following fundamental differences between reserves estimates and related disclosures prepared in accordance with SEC requirements and those prepared in accordance with NI 51-101:

- SEC reserves estimates are based upon different reserves definitions and are prepared in accordance with generally recognized industry practices in the US, whereas NI 51-101 reserves are based on definitions and standards promulgated by the COGE Handbook and generally recognized industry practices in Canada;
- SEC reserves definitions differ from NI 51-101 in areas such as the use of reliable technology, areal extent around a drilled location, quantities below the lowest known oil and quantities across an undrilled fault block;
- the SEC mandates disclosure of proved reserves and the Standardized Measure of Discounted Future Net Cash Flows and Changes Therein calculated using the year's monthly average prices and costs held constant, whereas NI 51-101 requires disclosure of reserves and related future net revenues using forecast prices and costs;
- the SEC mandates disclosure of reserves by geographic area, whereas NI 51-101 requires disclosure of reserves by additional categories and product types;
- the SEC does not require the disclosure of future net revenue of proved and proved plus probable reserves using forecast pricing at various discount rates;
- the SEC requires future development costs to be estimated using existing conditions held constant, whereas NI 51-101 requires estimation using forecast conditions;
- the SEC does not require the validation of reserves estimates by independent qualified reserves evaluators or auditors, whereas, without an exemption, NI 51-101 requires issuers to engage such evaluators or auditors to evaluate, audit or review their reserves and related future net revenue; and
- the SEC does not allow proved and probable reserves estimates to be aggregated, whereas NI 51-101 requires issuers to aggregate the estimates.

The foregoing is a general description of the principal differences only. The differences between SEC requirements and NI 51-101 may be material for certain properties.

## ENVIRONMENTAL AND REGULATORY MATTERS

### Government and Environmental Regulations

Our operations are subject to various levels of government controls and regulations in the countries where we operate. These laws and regulations include matters relating to exploration, production practices, occupational health and safety, environmental protection, midstream and marketing activities. These laws and regulations may increase the cost of doing business and, accordingly, affect profitability. We participate in many industry and professional associations through which our interests in new regulations and legislation are represented, and we monitor the progress of proposed regulatory and legislative amendments.

Laws and regulations change frequently and sometimes unpredictably. Regulatory complexity and stringency has increased over the past several years, as has the cost of compliance. Based on this trend, it is reasonably likely that the costs of compliance will continue to increase. We consider compliance with these regulations a necessary and manageable part of our business. We have been able to plan for and manage the increasing regulatory requirements without materially changing our business strategies or incurring significant or unreimbursed expenditures, though we are unable to predict the impact of future changes in compliance requirements on costs. We do not expect that the effect of these laws and regulations on our operations will be materially different than they would for any other oil and gas company of similar size and financial strength. We believe our operations comply, in all material respects, with applicable laws and regulations in the various jurisdictions where we operate.

The types of laws and regulations that affect our business most significantly fall into two categories: i) Operational and ii) Health, Safety and Environmental.

OPERATIONAL REGULATIONS

Our oil and gas exploration and production activities are subject to various international, federal, state, provincial, territorial and local laws and regulations.

Those laws and regulations affect a number of operational activities, including:

- land access;
- acquisition of seismic data;
- location of wells;
- drilling, completion and well servicing;
- transportation, storage and disposal of waste products arising from oil and gas operations;
- land restoration and well abandonment;
- pricing policies;

- royalties;
- various taxes and levies including income tax; and
- foreign trade and investment.

The implications of these laws and regulations to our business include direct costs in the form of tariffs, fees, taxes, rent and royalties and other direct charges measured by the type, region or intensity of activity. Indirect costs also arise from restricted access to certain areas of operation; restrictions on the type, frequency or conduct of permitted oilfield operations; limitations on production rates from certain oil and gas wells; forced pooling of oil and gas interests with third parties; changes in drill spacing units or well densities; infrastructure development; satisfaction of local content obligations for international projects; carried government participation in certain projects; and community consultation.

US Gulf of Mexico

Throughout the second half of 2010, the Bureau of Ocean Energy Management, Regulation and Enforcement (formerly the Minerals Management Service of the Department of the Interior) released new regulations governing drilling activities in the Gulf of Mexico. These regulations contain, among other things, increased requirements for wellbore integrity, blow-out prevention, well control equipment, personnel training, rig safety and spill response. We believe that the rigorous health, safety and environmental processes that we apply to our existing offshore operating activities enable us to satisfy these new regulatory obligations. Despite our ability to meet the new regulations, the new processes implemented by the Bureau to administer these regulations have delayed the permitting process, which could add to costs and longer cycle times for our Gulf of Mexico exploration and development drilling activities.

HEALTH, SAFETY AND ENVIRONMENTAL REGULATIONS

Our oil and gas operations are subject to various international, federal, state, provincial, territorial and local laws and regulations designed to regulate the impact of human activity on the natural environment and the safety of our worksites. These laws and regulations relate to:

- the types and quantities of substances and waste materials that can be released into the environment;
- use or removal of natural resources (such as water and timber) in exploration and production activities;
- abandonment, reclamation and remediation of worksites (including sites of former operations);
- development of emergency and community response plans; and
- implementation of safe work practices for employees and contractors.

We are committed to operating within these laws and regulations and to conducting our business in a safe and environmentally responsible manner.

Environmental regulations continue to evolve and are becoming more complex. To reduce our risk of non-compliance with these laws, we apply internal tools and processes, and industry standards and best practices that meet or exceed our legal obligations. Where regulations do not exist, or where we consider them to be insufficiently developed, we observe Canadian standards or internationally accepted industry environmental management practices.

Our Health, Safety, Environment and Social Responsibility group (HSE&SR) helps ensure our worldwide operations are conducted in a safe, ethical and socially responsible manner. Our HSE&SR practices are reported to our board of directors throughout the year. Nexen's overall HSE&SR program is guided by our corporate HSE&SR management system that incorporates the continual improvement model of Plan, Do, Check, Act and our own 12 guiding elements for divisional performance. For more information on Nexen"s HSE&SR governance model, refer to the Responsible Development section of our website as well as our sustainability report, both available at www.nexeninc.com.

Our performance against this system is reviewed by an external auditor every three years, and we have been recognized by the Goldman Sachs SUSTAIN Report and Dow Jones Sustainability Index (North America) as a sustainability leader. Our progress is publicly reported in our sustainability report.

Environmental and Social Responsibilities

Environmental and social responsibility has become an increasingly significant measurement of corporate performance by governments, investors and the public. The oil and gas industry is being challenged to improve its response to the effects of climate change, embrace responsible operating practices, including the preservation of water, land, air and biodiversity, and consult and invest in the communities it relies upon to do business. The level of regulation associated with these issues varies considerably throughout the jurisdictions in which we operate. Based on the current trend, it is reasonably likely that our regulatory obligations and the associated cost of compliance will increase. Due to the uncertainty surrounding the future implementation of regulations, we are unable to estimate our costs of compliance in the future. We do, however, look at a range of regulatory scenarios to try to determine the possible compliance costs.

As a result of our commitment to responsible operating practices and social responsibility, we believe we are well positioned to meet the challenges of increasing environmental regulation and social expectations that have become a significant component of sustainable resource development. We have built a corporate culture of integrity and respect for the communities and environments in which we operate and have developed policies and practices for continuing compliance with all environmental laws and regulations.

CLIMATE CHANGE

Nexen believes that climate change and the transition to a low carbon energy system are important issues. For the past decade, Nexen has been active in planning and preparing for carbon regulation and has been engaged in public discussions on this matter in jurisdictions where we operate. We have also participated in carbon markets, renewable energy initiatives and a range of carbon offset/crediting projects. We currently manage compliance for our three producing assets in the UK North Sea and in our operations in Canada (Alberta and British Columbia). The Canadian Federal government has yet to pass climate change legislation. Canada has previously announced their intent to mirror the US regulatory approach for climate-related matters but continues to state they do not have to wait if their interests were best served by unilateral action. In the US, there has been no progress on comprehensive climate/energy legislation and none is expected until after the November 2012 presidential election.

Any required reductions in the greenhouse gases (GHGs) emitted from our operations could result in increases to our capital or operating expense.

Alberta became the first jurisdiction in Canada to enact and implement binding industrial sector emission reductions (a one-time from base, 12% reduction in carbon intensity vs. a 2003—2005 baseline) on facilities annually emitting more than 100 kilo-tonnes of CO2 equivalent. Facilities unable to achieve internal reductions have an unlimited ability to achieve compliance through payment into a technology fund at the rate of $15 per tonne of CO2 equivalent or through the purchase of Alberta-based emission offset credits.

British Columbia enacted legislation in November 2007 titled the Greenhouse Gas Reduction Targets Act, which targets a 33% reduction in current provincial GHG emissions by 2020. British Columbia has been actively engaged in the Western Climate Initiative and recently enacted a GHG reporting regulation. For oil and gas operations, the facility emission reporting threshold is zero (i.e., all facilities must report regardless of size). The province also applied an economy-wide carbon tax on all hydrocarbon fuels sold in the province. The tax started at $10/tonne of CO2 in 2008 and will increase $5 per year until it reaches $30 per tonne in 2012. It is currently unclear whether British Columbia will introduce a cap and trade system in partnership with the other Western Climate Initiative jurisdictions (California, Quebec, Ontario and Manitoba) or whether they will continue with their current or expanded carbon tax system. This situation may continue until after the next provincial election in 2013.

In 2008, the European Union (EU) introduced Phase II of the Emissions Trading Scheme (ETS), which will run until the end of 2012. Under Phase II of the ETS, member states were required to establish a national allocation plan approved by the EU. The system covers CO2 from certain combustion and flaring activities, and member states are allowed to manage allocation across their industrial base as they see fit. Installations have the ability under the ETS to purchase allowances or other eligible instruments to ensure compliance. Phase III, scheduled to run from 2013 to 2020, may include a transition from the gratis allocation of allowances to the use of auctioning. Post-2012 auctioning of allowances for all electricity generation activities and phased reduction of free allocation of allowances for other activities, as well as phased reduction of allowance availability in general, are expected to increase our annual cost of compliance. Proposals to increase the EU reduction obligation from 20 to 30%, if implemented, could also increase our annual cost of compliance.

In 2009, the US Environmental Protection Agency (EPA) announced its findings that GHGs pose a threat to public health. In the absence of other federal programs to regulate GHGs, the EPA has initiated regulatory activity under the authority of the Clean Air Act. The facility threshold for this action is currently set at 25,000 tonnes per year, a level that none of our operated US facilities currently emits. The EPA has expressed interest in regulating smaller GHG sources, though the agency has yet to fully implement its regulation of the larger sources and no regulatory proposals have been finalized. The EPA moved back deadlines several times in 2011 and it is unclear if they will aggressively pursue these initiatives in 2012. The impact of EPA activity in the area of GHG regulation is expected to be minimal on our current operations in the Gulf of Mexico.

The Canadian Council of Ministers of the Environment (the CCME is comprised of the federal and provincial ministers) decided to pursue a federal air quality management system for the regulation of air pollutant emissions and ambient air quality. Work on equipment performance standards and ambient air quality objectives progressed through 2011. Draft regulations are expected in late 2012 with implementation beginning in 2013. While we could face technical challenges in meeting minimum emission standards for certain pollutants, we are unable at this time to estimate the cost of compliance and impact on our operations.

To meet our current and projected GHG emissions obligations, we continue to pursue a four-point emissions management strategy:

- reduce direct GHG emissions at our facilities;
- self-generate carbon credits from wind power;
- acquire carbon credits through qualified projects and authorized agencies; and
- participate in eligible international and domestic offset projects.

WATER

We have developed a water strategy designed to minimize water use in our exploration and production operations. This strategy is embodied by the following four principles:

- optimize water use efficiency;
- minimize our impacts on ecosystem functions and ensure public health and safety are not affected by our activities;
- engage with stakeholders to promote responsible watershed management and evaluate opportunities to provide water management benefits to stakeholders; and
- measure and communicate our water management performance.

This strategy was implemented in 2009 with an emphasis on compliance and early adoption of best practices, incorporating water assessment in our investment decision-making process and developing water management systems to enhance water tracking and reporting. Our water data management project, which started in 2011, provides us with enhanced abilities to improve water efficiency.

LAND AND BIODIVERSITY

Our land use practices are based upon principles of minimal disturbance and a legal commitment to return the land to a natural state after responsibly producing oil and gas resources. We also recognize our ability to effectively access land is directly linked to the way in which we manage the potential environmental impacts and in how we engage with local communities, stakeholders, regulators and other industries to reduce the cumulative effects of our projects throughout their life—cycle.

For many stakeholders, a company’s ability to meet environmental expectations is a significant criterion upon which their decision to invest or conduct business is based. A failure to meet those expectations can limit access to exploration, development and partnership opportunities. Therefore, we believe that environmental and social responsibility performance is directly linked to economic performance.

We have outlined and more fully discussed our environmental practices and policies in our sustainability report, available on our website at www.nexeninc.com.

Community Investment

Giving back to the communities in which we operate is a deeply rooted value at Nexen. The company's "ReachOut — Giving, Matching, Helping" community involvement strategy supports the priorities of our employees and communities while providing a strategic link to our business.

The "ReachOut" program focuses on three key areas:

- Giving — Supporting communities where Nexen has operations through meaningful corporate gifts;
- Matching — Nexen matching charitable contributions made by our employees; and
- Helping — Nexen builds employees engagement and stronger communities through volunteering.

Details regarding Nexen's community investment initiatives are available in our sustainability report and on our website.

Environmental Provisions and Expenditures

Meeting the challenges of environmental regulation and our commitment to sustainable resource development affects all stages of our operations and generally increases their cost. Environmental commitments and regulation can increase the operating or capital cost of operations, delay requisite permits or approvals from issuing authorities and could result in unprofitable operating conditions. During 2011, we incurred both capital and operational expenses, including expenses related to environmental control facilities. Those costs were not material and did not impair our ability to execute our business or operating strategy. We will continue to incur these costs in the future and expect they will be manageable. At December 31, 2011, $2,076 million ($3,481 million undiscounted, adjusted for inflation) has been provided in our Consolidated Financial Statements for asset retirement obligations.

EMPLOYEES

We had 3,067 employees on December 31, 2011.

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RISK FACTORS

Our operations are exposed to various risks, some of which are common to other operations in the oil and gas industry and some of which are unique to our operations. Certain risks set out below constitute “forward-looking statements” and the reader should refer to the special note regarding “Forward-Looking Statements” set out on page 2 of this AIF.

Our profitability and liquidity are highly dependent on the price of crude oil and natural gas.

Our financial performance depends significantly on the price of crude oil and natural gas we receive for our production. Extended periods of lower commodity prices may reduce our level of spending for oil and gas exploration and development, and may have a material adverse effect on our results of operations. Lower realized commodity prices could also have a material adverse effect on our estimates of proved reserves, the carrying value of our oil and gas properties, the level of planned drilling activities and future growth. Crude oil and natural gas are commodities that are price-sensitive to numerous worldwide factors, many of which are beyond our control. These factors include, but are not limited to:

- global and regional supply and demand for crude oil, natural gas, and natural gas liquids;
- the costs of exploring for, developing, producing and transporting crude oil, natural gas and natural gas liquids;
- weather conditions;
- the effect of energy conservation efforts;
- limits on transportation capacity to alternative energy markets;
- the pricing and availability of alternative fuels and energy;
- production quotas set by the Organization of Petroleum Exporting Countries (OPEC), and their ability to meet those quotas;
- worldwide geopolitical events, armed conflict and acts of terrorism;
- domestic and foreign government regulations and taxes; and
- the overall economic environment worldwide.

Exploration, development and production activities may not be successful and carry a risk of loss.

Acquiring, developing and exploring for oil and natural gas involves many risks. There is a risk that we will not encounter commercially productive oil or gas reservoirs and that the wells we drill may not be productive or not sufficiently productive to recover a portion or all of our investment. We may not achieve production targets should our reservoir production decline sooner than expected. Seismic data and other exploration technologies we use do not provide conclusive proof prior to drilling a well that crude oil or natural gas is present or may be produced economically. The costs of drilling, completing and operating wells are often uncertain, and drilling operations may be extended, curtailed, delayed or cancelled as a result of a variety of factors, including:

- encountering unexpected formations or pressures;
- blowouts, wellbore collapse, equipment failures and other accidents;
- craterings and sour gas releases;
- accidents and equipment failures;
- uncontrollable flows of oil, natural gas or well fluids; and

- environmental risks.

These occurrences may also result in damage to or destruction of wells, facilities or other property, pollution, injury to persons or loss of life. We may not be fully insured against all of these risks, and insurance may not be available for certain risks, such as named wind storms. Our contractual allocation of risk amongst joint-operating partners and service providers may not operate as intended. Losses resulting from the occurrence of these risks may materially impact our operational activities and financial results.

We operate in harsh and unpredictable climates and locations where our access is regulated, which could adversely impact our operations.

Some of our facilities are located in harsh and unpredictable climates and locations that can experience extreme weather conditions and natural disasters, such as sustained ambient temperatures above 40°C or below -35°C, flooding, droughts, wind and dust storms, difficult terrain, high seas, monsoons and hurricanes. These conditions are difficult to anticipate and cannot be controlled. In these conditions, operations can become difficult or unsafe and are often suspended. Some of our facilities and those that our facilities rely upon (such as pipelines, power, communication and oil field equipment) are vulnerable to these types of extreme weather conditions and may suffer extensive or catastrophic damage as a result. If any such extreme weather were to occur, our ability to operate certain facilities and proceed with exploration or development programs could be seriously or completely impaired or destroyed and could have a material adverse effect on our business, financial condition and results of operations. The insurance we maintain may not be adequate to cover our losses resulting from disasters or other business interruptions.

In some areas of the world, access and operations can only be conducted during limited times of the year due to weather or government regulation. These adverse conditions can limit our ability to operate in those areas and can intensify competition during these periods for oil field equipment, services and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs and could have a material adverse effect on our business, financial condition and results of operations. Changing weather patterns may increase the frequency, intensity or duration of these weather conditions and accordingly exacerbate their impacts on our operations.

Deep-water operations involve additional risk.

Our deep-water operations take place in difficult and unpredictable environments and are subject to the risk of blowouts and other catastrophic events that could result in suspension of operations, damage to equipment, harm to individuals and damage to the environment. While various precautions are taken to reduce the risk, these efforts cannot eliminate the risk that such events may occur. The consequences of catastrophic events occurring in deep-water operations can be more difficult and time-consuming to remedy. As well, the remedy may be made more difficult or uncertain by the water depths, pressures and cold temperatures encountered in deep-water operations, shortages of equipment and specialists required to work under these conditions, or the absence of appropriate means to effectively remedy such consequences. Emergency response plans that we have in place to address the environmental impact from spills, leaks, blowouts or other events in connection with our operations may not be entirely effective in mitigating the consequences of blowouts or other catastrophic events. Our deep-water operations could also be affected by the actions of our contractors and agents that could result in similar catastrophic events at their facilities, or could be indirectly affected by catastrophic events occurring at third-party deep-water operations. In either case, this could give rise to liability for us, damage to our equipment, harm to individuals, force a shutdown of our facilities or operations, or result in a shortage of appropriate equipment or specialists required to perform our planned operations. It is possible that the allocation of liabilities and risk of loss arising from deep-water operations and associated insurance coverage will not be sufficient to address the costs arising out of such events.

The costs in connection with a blowout or other catastrophic event could be material and we may not maintain sufficient insurance to address such costs. As it pertains to these types of deep-water risks, we maintain insurance for costs relating to property damage to our facilities, control of well including drilling relief wells, removal of wreck, pollution clean—up, liability for bodily injury and property damage to third parties, including our contractors, and liability for damage to natural resources.

For property damage to our facilities, we are covered for amounts up to the replacement cost of those facilities. For control of well, pollution clean—up, liability for bodily injury and property damage to third parties caused by pollution, we are insured for amounts up to US$350 million. We have separate, additional insurance covering liability for bodily injury and property damage to third parties of up to US$465 million, which responds whether the liability arises from pollution or from other causes. Where we are the operator of a well or a facility, we are insured for our working interest share of US$35 million of coverage relating to our obligations under Section 1001 of the US Oil Pollution Act of 1990, which includes liability for damage to natural resources. For declared deep-water wells, we are insured for our working interest share of up to US$250 million for costs related to control of the well. Our insurance for "pollution clean—up" covers: i) reasonable and necessary expenses incurred; ii) liability to any governmental entity for clean-up and removal costs and expenses; and iii) liability for costs and expenses of governmental action. In each case we are covered to the extent reasonable and necessary to minimize or remediate, or prevent further, injuries to persons or loss or damage to the property of others arising out of seepage, pollution or contamination. Our insurance for "liability for damage to natural resources" covers sums for which we may be liable as a result of loss of or damage to, including loss of use of, “natural resources” arising out of seepage, pollution or contamination. “Natural resources” include land, fish, wildlife, plantlife, air, water, ground water, drinking water supplies and other such resources.

Following the 2010 explosion and sinking of the deep-water Horizon rig in the Gulf of Mexico, the off-shore drilling industry is under increased scrutiny from governments, environmental groups, investors and the general public. The resultant increase in regulation of deep-water operations has increased our costs of compliance, though not presently to such extent that our current or proposed drilling activities have become uneconomic. A risk also exists that liability limits under existing regulations could be increased substantially by the US Government, which would increase our potential liability in the event of a blowout or other catastrophic event. We also may not be able to access sufficient pooled liability funds set up in the US Gulf of Mexico for costs of a blowout or other catastrophic event.

Catastrophic events in connection with our deep-water operations, such as blowouts and oil spills, could result in material costs and reputational damage, and could have a material adverse effect on our credit rating, our ability to raise capital or the cost of such capital.

Competitive forces may limit our access to natural resources and create labour and equipment shortages.

The oil and gas industry is highly competitive, particularly in the following areas:

- gaining access to areas or countries known to have available resources;
- searching for and developing new sources of crude oil and natural gas reserves;
- hiring the equipment and expertise required to safely and cost-effectively develop resources;
- constructing and operating crude oil and natural gas pipelines and facilities; and
- transporting and marketing crude oil, natural gas and other petroleum products.

Our competitors include national oil companies, major integrated oil and gas companies and various other independent oil and gas companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to customers. Key success factors in each of these markets are price, product quality, logistics and reliability of supply.

Competitive forces may result in shortages of: i) prospects to drill; ii) labour; iii) drilling rigs and other equipment to carry out exploration, development or operating activities; and iv) shortages of infrastructure to produce and transport production. It may also result in an oversupply of crude oil and natural gas. Each of these factors could negatively impact our costs and prices and, therefore, our financial results.

Some of our production is concentrated in a few producing assets.

A significant portion of our current and future production is generated from highly productive individual wells or central production facilities. Examples include:

- Buzzard, Scott and Ettrick production facilities in the UK North Sea;
- our Usan project offshore Nigeria;
- our Long Lake operation in the Athabasca oil sands; and
- upgrading facilities at Syncrude in the Athabasca oil sands.

As significant production is generated from each asset, any single event that interrupts one of these operations could result in the loss of production.

We operate in countries with political, economic and security risks.

We operate in numerous countries, some of which may be considered politically and economically unstable. A portion of our revenue is derived from operations in these countries. As a result, our financial condition and operating results could be significantly affected by risks associated with international activities, including:

- civil unrest and general strikes;
- political instability, the risk of war and acts of terrorism;
- taxation policies, including royalty and tax increases, retroactive tax claims and investment restrictions;
- expropriation or forced renegotiation or modification of existing contracts;
- exchange controls, currency fluctuations, devaluation or other activities that limit or disrupt markets and restrict payments or the movement of funds;

- the possibility of being subject to exclusive jurisdiction of foreign courts in connection with legal disputes relating to licences to operate and concession rights in countries where we currently operate; and
- difficulties in enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations.

The impact that future potential terrorist attacks or regional hostilities may have on the oil and gas industry, and on our operations in particular, is not known at this time. Uncertainty surrounding military strikes or a sustained military campaign may affect operations in unpredictable ways, including disruptions of fuel supplies and markets, particularly crude oil, and the possibility that infrastructure facilities, including pipelines, production facilities, processing plants and refineries, could be direct targets of, or indirect casualties of, an act of terror or war. We may be required to incur significant costs in the future to safeguard our assets against terrorist activities or to remediate potential damage to our facilities. There can be no assurance that we will be successful in protecting ourselves against these risks and the related financial consequences.

We are required to obtain regulatory approvals in order to operate.

Our oil and gas operations are subject to various international, federal, state, provincial, territorial and local laws and regulations designed to regulate the conduct of oil and gas exploration, development and production activities. Those laws and regulations govern, amongst other things:

- the types and quantities of substances and waste materials that may be discharged into the surface and sub-surface environment;
- the use or removal of natural resources (such as water and timber) in exploration and production activities;
- the release of greenhouse gases, such as carbon dioxide and methane, into the atmosphere;
- the protection of endangered species;
- the abandonment, reclamation and remediation of worksites (including sites of former operations);
- the issuance of permits and other regulatory approvals in connection with exploration, drilling and production

activities, the construction of roads, pipelines and other regional transportation infrastructure; and

- marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment.

These laws and regulations may impose significant liabilities on a failure to comply with their requirements. Significant changes to the environmental laws and regulations governing our current operations, including many of the proposed initiatives to regulate greenhouse gas emissions, may have a material adverse effect on the oil and gas industry, including our company. The cost of meeting new environmental and climate change regulations may have a material adverse effect on the viability of future projects, our results of operations, cash flows and financial condition.

Our oil sands projects face additional risks compared to conventional oil and gas production.

Oil sands developments are large and capital intensive projects which rely on specialized production technologies such as SAGD. Our Long Lake development is a fully integrated production, upgrading and cogeneration facility that relies on specialized upgrading technology. Given the initial investment and operating costs to produce bitumen, the payout period for these projects is longer and the economic return is lower than a conventional light oil project with an equal volume of reserves.

Risks associated with oil sands projects include the following:

SAGD BITUMEN PRODUCTION MAY NOT ACHIEVE OUR EXPECTATIONS

Our estimates of performance and recoverable volumes for oil sands projects are based primarily on sample reservoir data, the results of pilot projects, our experience with the Long Lake project, and industry performance from SAGD operations in similar reservoirs in the McMurray formation in the Athabasca oil sands. While some of the wells will achieve the performance expectations established prior to project sanction, there can be no certainty that these wells will maintain these levels or that our overall SAGD operation will produce bitumen at the expected levels or steam-to-oil ratio. If the assumed production rates or steam-to-oil ratio are not achieved for reasons which could be related to one or all of design, facility or reservoir performance, or the presence of problematic geological features in the reservoir such as shales or pockets of water, we might have to drill additional wells to maintain optimal production levels, construct additional steam generating capacity, or reconfigure, redesign or construct additional facilities. These could have an adverse impact on the future activities and economic return of the project.

APPLICATION OF A NEW BITUMEN UPGRADING PROCESS AT LONG LAKE

The proprietary OrCrudeTM process we are using at Long Lake to upgrade raw bitumen to synthetic crude is the first commercial application of this process. Although the commercial upgrader at Long Lake has been operating since January 2009, there is no certainty that it will sustain or achieve the results that are now being seen or forecast for reasons which could be related to multiple factors, some of which may be related to one or all of design, facility performance, or integration of our facilities. As a result, we may be required to reconfigure, redesign or construct additional facilities. If we are unable to continue to upgrade the bitumen for any reason, we may decide to sell the bitumen directly to third parties without upgrading, which would expose us to the following risks:

- the market for bitumen may be limited;

- additional costs would be incurred to purchase diluent for blending and transporting bitumen;
- there could be a shortfall in the supply of diluent, which may cause its price to increase;
- the market price for bitumen is generally lower than for PSCTM, reflecting its quality differential; and
- additional costs would be incurred to purchase natural gas for use in generating steam for the SAGD process since we would not be producing synthetic gas from the upgrading process.

If any of these factors arise, our operating costs would increase or our revenues would decrease from what we have assumed. This would materially decrease expected earnings from the project and the project may not be profitable under these conditions.

INTEGRATION OF A SAGD FACILITY AND AN UPGRADING FACILITY AT LONG LAKE

The combination of a SAGD facility with the OrCrudeTM upgrading facility at Long Lake is a unique, patented combination of equipment. Although this integrated facility is expected to achieve lower operating costs and has demonstrated that the combination of technologies works, the complexity and degree of interdependency of the facilities creates conditions for interruptions and limitations to operations impacting complete operation of the facilities. This could require future reconfigurations and modifications to improve the reliability, durability and efficiency of operation initially contemplated by its design. There is no certainty that any such changes will successfully resolve the problems experienced or that we may experience in the future, which would expose us to additional costs, and associated downtime of one or both of the SAGD production and upgrader facilities, and the potential for increased maintenance requirements.

These factors could have a significant adverse impact on the future activities and economic returns of the Long Lake project.

DEPENDENCE UPON PROPRIETARY TECHNOLOGY AT LONG LAKE

The success of the Long Lake project and our investment depends on the proprietary technology of Ormat Industries Ltd. (Ormat) and proprietary technology of third parties that has been, or is required to be, licenced for the project. Ormat and Nexen rely on intellectual property rights and other contractual or proprietary rights, including (without limitation) copyright, trademark laws, trade secrets, confidentiality procedures, contractual provisions, licences and patents, to secure the rights to utilize Ormat's proprietary technology and the proprietary technology of third parties. Ormat and Nexen may have to engage in litigation to protect the validity of its patents or other intellectual property rights, or to determine the validity or scope of patents or proprietary rights of third parties. Litigation can be time-consuming and expensive, whether successful or not. The process of seeking patent protection can itself be long and expensive. There is no assurance that any pending or future patent applications of Ormat or such third parties will actually result in issued patents or that, if patents are issued, they will be of sufficient scope or strength to provide meaningful protection or any commercial advantage to Ormat. Others may develop technologies that are similar or superior to: i) the technology of Ormat or third parties; or ii) the design around the patents owned by Ormat and/or third parties.

OPERATIONAL HAZARDS

Our oil sands projects are designed to process large volumes of hydrocarbons at high-pressure and temperatures and also handle large volumes of high-pressure steam. Equipment failures could result in damage to the project facilities and liability to third parties against which we may not be able to fully insure or may elect not to insure because of high premium costs or for other reasons.

Certain components of the Long Lake facilities produce sour gas, which is gas containing hydrogen sulphide and carbon monoxide. Sour gas is a colourless, corrosive gas that is toxic at relatively low levels to plants and animals, including humans. Carbon monoxide is a colourless, odorless and tasteless gas that is toxic at relatively low levels to humans and animals. The project includes integrated facilities for handling and treating the sour gas and for consuming the carbon monoxide as a fuel, including the use of gas-sweetening units, sulphur recovery systems and emergency flaring systems. Failures or leaks from these systems or other exposure to sour gas produced as part of the project could result in damage to other equipment, liability to third parties, adverse effect to humans, animals and the environment, or the shutdown of operations.

The Long Lake project is susceptible to loss of production, slowdowns or restrictions on its ability to produce higher-value products due to the interdependence of its component systems. Severe climatic conditions can cause reduced production and, in some situations, result in higher costs. SAGD bitumen recovery facilities and development and expansion of production can entail significant capital outlays. The costs associated with synthetic crude oil production are largely fixed and, as a result, per unit operating costs depend largely on production levels.

Unconventional gas resource plays carry additional risks and uncertainties.

Shale gas and CBM are unconventional gas resources which are produced through the application of relatively new technologies, such as hydraulic fracing. Some of the uncertainties associated with development of unconventional gas resources are as follows:

- shales are typically less permeable than conventional gas reservoirs and can therefore require more extensive, and expensive, completion technologies, which can increase costs or which may not be successful;
- seasonal access to certain areas may limit activities or increase competition for equipment and/or qualified personnel;
- global demand for the specialized equipment and personnel required to develop and produce unconventional gas resources is strong, and access to the equipment may become more expensive and possibly limited;
- some unconventional gas resources are located in areas of the world with limited access to regional infrastructure for the sale of production;
- limitations on local water availability may limit our ability to develop shale gas, which generally requires more water to develop and produce than conventional resources do;
- some jurisdictions have banned hydraulic fracturing activities pending further review of the practice amidst public concern and allegations it causes contamination of drinking water aquifers and other subsurface damage; and
- regulatory approval is required to drill more than one well per section, and as a result, the timing of drilling programs and land development can be uncertain.

Without reserve additions, our reserves and production will decline over time and we require capital to produce remaining reserves.

Our future crude oil and natural gas reserves and production, and therefore our future operating cash flows and results of operations, are highly dependent upon our success in exploiting our current reserves and acquiring or discovering additional reserves in the future. Without reserve additions through exploration, development or acquisitions, our reserves and production will decline over time as reserves are produced. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flow from operations is insufficient and external sources of capital become limited or unavailable, our ability to make the necessary capital investments to maintain and expand our oil and natural gas reserves and production may be reduced.

Discovered oil and natural gas accumulations are generally only produced when they are economically recoverable. As such, oil and gas prices, and capital and operating costs have an impact on whether accumulations will ultimately be produced.

Our reserves include undeveloped properties that require additional capital to bring them on stream.

Proved and probable oil and gas reserves include undeveloped reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is still required before such wells begin production. Reserves may be recognized when plans are in place to make the required investments to convert these undeveloped reserves to producing. Circumstances such as a sustained decline in commodity prices or poorer than expected results from initial activities could cause a change in the investment or development plans which could result in a material change in our reserves estimates.

Projects may not be completed on time or within budget.

We are involved with a variety of projects at any given time, including exploration and development projects, and the construction and expansion of facilities and pipelines. Project delays may adversely effect expected revenues and cost overruns may adversely effect project economics. Our ability to complete projects on time and on budget depends on many factors beyond our control, including the availability of equipment and personnel, land access, weather, accidents, equipment breakdown, the need for government and regulatory approvals, unexpected or uncontrollable increases in the costs of materials or labor, and access to pipeline and processing capacity.

Pipeline and export infrastructure in North America is limited.

An increase in the supply of crude oil and natural gas from unconventional sources in North America has softened commodity prices relative to many foreign markets and is expected to fill existing North American pipeline infrastructure. Without new transportation and export infrastructure, the current transportation network may not be able to accommodate the increased volumes of oil and gas expected from the development of unconventional oil and gas, including oil and gas produced from our oil sands and shale gas properties in western Canada. This, in turn, could delay the development of our oil and gas reserves in western Canada. In addition, North America has limited export infrastructure and without new export infrastructure, we may be required to sell our production into the North American markets at lower prices than are available in other foreign markets, which could materially and adversely affect our financial performance.

Negative public perception of oil and gas development, oil sands and shale gas hydraulic fracturing may harm our corporate reputation and profitability.

The development of the oil sands and shale gas figures prominently in political, media and activist commentary on the subjects of greenhouse gas emissions, water usage, hydraulic fracing, and potential for environmental damage. Concerns over greenhouse gas emissions, land use and water contamination may directly or indirectly harm the profitability of our current oil sands and shale gas projects and the viability of future projects in a number of ways, including:

- creating significant regulatory uncertainty that could challenge the economic modeling of future projects and delay sanctioning;
- motivating extraordinary environmental regulation of those projects by governmental authorities that could result in changes to facility design and operating requirements, thereby increasing the cost of construction, operation and abandonment; and
- compelling legislation or policy that could limit the purchase of crude oil produced from the Athabasca oil sands by governments or other institutional consumers that, in turn, limits the market for this crude oil and reduces its price.

Concerns over these issues may also harm our corporate reputation and limit our ability to access land and joint venture opportunities in certain jurisdictions throughout the world.

Our lands could be subject to aboriginal claims.

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Certain aboriginal peoples have filed a claim against the Government of Canada, the Province of Alberta, the Province of British

Columbia, and certain governmental entities. They are claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, Alberta and Fort Nelson, British Columbia, including the lands on which our shale gas and oil sands interests, and those of most other oil sands and shale gas operators in Alberta and British Columbia, are located. As a result, aboriginal consultation on surface activities is required and may result in timing uncertainties or delays of future development activities. Such claims, if successful, could have a significant adverse effect on our oil sands and shale gas developments.

Our energy marketing operations expose us to the risk of trading losses and liquidity constraints.

Our energy marketing operations expose us to the risk of financial losses from various sources, which may have a material adverse effect on our financial performance. Our energy marketing team maintains a portfolio comprised of long and short physical and financial positions, which may be significant in size or number at any time. This portfolio of positions is managed based on a trading thesis for expected future pricing levels and trends in forward or regional markets. Unanticipated volatility in commodity price levels and trends upon which those positions are based may cause a position to decrease in value. The transportation and storage assets and contracts undertaken by our energy marketing business may decrease in value due to changes in temporal and regional commodity pricing.

Significant changes in commodity and financial markets could require us to provide additional liquidity if collateral is required to be placed with counterparties. We may also be required to reduce some of our energy marketing activities. Adverse credit-related events such as a downgrade of our credit rating to non-investment grade could require additional collateral to be placed with counterparties. Adverse, broad-based, industry credit-related events could also negatively affect trading counterparties who fail to fulfill their contractual obligations.

Use of marine transportation may expose us to the risk of financial loss and damaged reputation.

From time to time, we may choose to charter marine vessels for the transportation of crude oil. This may expose us to the risk of financial loss and damaged reputation in the event of oil spills. Marine transportation is subject to hazards such as capsizing, collision, acts of piracy and damage or loss from severe weather conditions. These hazards could result in serious personal injury or loss of human life, significant damage to property and equipment, environmental pollution, impairment of operations, risk of financial loss and damaged reputation in the event of oil spills. We may not be insured against all of these risks and uninsured losses and liabilities arising from these hazards could reduce the funds available to us for capital, exploration and investment spending, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our debt and other financial commitments may limit our financial and operating flexibility.

As of December 31, 2011 our long-term debt was approximately $4.5 billion. We also have commitments under leases, drilling rig contracts, transportation and storage contracts, and purchase obligations for services and products. Our debt levels and financial commitments could have significant and adverse consequences to our business, including:

- an increased sensitivity to adverse economic and industry conditions;
- a limited ability to fund future working capital and capital expenditures, engage in future acquisitions or development activities, or to otherwise fully realize the value of assets or opportunities, because a substantial portion of our cash flows are required to service debt and other obligations;

- a limited ability to plan for, or react to, industry trends; and
- an uncompetitive position relative to our competitors whose debt and financial commitment levels are lower.

The inability of counterparties and joint operating partners to fulfill their obligations to us could adversely impact our results of operations.

Credit risk arises from the sale of production and products our energy marketing group buys for resale, from financial contracts we acquire for hedging and trading purposes and from our joint venture partners for their share of capital and operating costs. There is the risk of loss and additional burden for amounts in excess of available remedies if counterparties or joint venture partners do not or cannot fulfill their contractual obligations.

A downgrade in our credit rating could increase our cost of capital and limit access to capital.

Rating agencies regularly evaluate the company and their ratings of our long-term and short-term debt are based on a number of factors. This includes their perception of our financial strength as well as other factors not entirely within our control, including conditions affecting the oil and gas industry generally, and the wider state of the economy. We cannot be assured that one or more of our credit ratings will not be downgraded. Our borrowing costs and ability to raise funds are directly impacted by our credit ratings.

In addition, credit ratings may be important to customers or counterparties when we compete in certain markets and when we seek to engage in certain transactions including transactions involving over-the-counter derivatives.

It is our objective to maintain high-quality credit ratings appropriate for our business activities. A credit-rating downgrade could potentially limit our access to private and public credit markets and increase the costs of borrowing under existing facilities. A reduction in our credit ratings could also have a significant impact on certain trading revenues, particularly in those businesses where counterparty creditworthiness is critical. A reduction could trigger collateralization requirements related to physical and financial derivative liabilities with certain marketing counterparties and pursuant to certain facility construction contracts. The occurrence of any of the foregoing could adversely affect our ability to execute portions of our business strategy and could have a material adverse effect on our liquidity and capital position.

In connection with certain over-the-counter derivatives contracts and other trading agreements, we could be required to provide additional collateral or to terminate transactions with certain counterparties in the event of a downgrade of our credit ratings. The amount of additional collateral required depends on the terms of the contract and is usually a fixed incremental amount and/or the market value of the exposure.

Fluctuations in foreign exchange rates may have a material adverse effect on our results of operations.

Our operations are sensitive to fluctuations in foreign currency exchange rates, particularly between the Canadian dollar, the US dollar and the British Pound. A substantial portion of our activities are transacted in, or referenced to, US dollars, including sales of crude oil and natural gas, capital spending and expenses for our oil and gas operations, and short-term and long-term borrowings. As a result, changes in exchange rates could materially and adversely affect our results of operations.

## CAPITAL STRUCTURE

### Authorized Capital

Our authorized capital consists of an unlimited number of common shares without nominal or par value and an unlimited number of preferred shares without nominal or par value, issuable in series. As at December 31, 2011, 527,892,635 common shares were issued and outstanding. No preferred shares were issued.

### Common Shares

Each common share entitles the holder to receive notice of, attend and one vote at all meetings of our shareholders, other than meetings at which only the holders of a specified class or series of shares are entitled to vote. The holders of common shares are entitled, subject to the rights, privileges, restrictions and conditions attached to other classes of shares of Nexen, to receive any common share dividend declared by the board and to receive the remaining property of Nexen upon dissolution of the company. There are no pre-emptive or conversion rights attached to the common shares and the common shares are not subject to redemption. All common shares currently outstanding, and potentially outstanding upon the exercise of outstanding options, are, or will be, fully paid and non-assessable.

### Preferred Shares

Preferred shares may be issued in one or more series. Each series consists of such number of shares and with the designation, rights, restrictions, conditions and limitations as determined by our board of directors.

Holders of preferred shares are not entitled to receive notice of, attend or vote at our shareholder meetings, unless payments of four quarterly preferred share dividends of any series remain outstanding and unpaid. As long as any preferred share dividend of any series remains in arrears, the holders of preferred shares are entitled to receive notice of and to attend all meetings of our shareholders and are entitled to one vote in respect of each preferred share held. In these circumstances, holders of preferred shares will be entitled, voting separately and exclusively as a class, to elect two directors to our board. Issued preferred shares will have priority over the common shares in payment of dividends and in the distribution of assets in the event of liquidation, dissolution or winding-up of Nexen. Each series of preferred shares rank in parity with preferred shares of every other series with respect to priority in payment of dividends and in the distribution of assets.

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Shareholder Rights Plan

A shareholder rights plan (the Plan) exists for holders of common shares of Nexen. The Plan creates a right for each present and future outstanding common share, entitling the holder to acquire additional common shares during the term of the right. Rights created under the Plan, which can only be exercised when a person acquires 20% or more of our common shares, entitle each shareholder, other than the 20% buyer, to acquire additional common shares at one-half of the market price at the time of exercise. Prior to the separation date, the rights are not separable from the common shares and no separate certificates are issued. The separation date would typically occur at the time of an unsolicited takeover bid, but our board can defer the separation date. The Plan was reapproved by shareholders at our annual general meeting in 2011 and will remain in force until the earlier of the date that the Plan is terminated by its terms and the termination of our annual general meeting in 2014. The Plan must be reapproved by shareholders at or before our annual general meeting in 2014 to remain effective past that date. A copy of the Plan is available on our website at www.nexeninc.com.

Credit Ratings

The following information relating to our credit ratings is provided as it relates to Nexen's financing costs, liquidity and operations. Specifically, credit ratings affect our ability to obtain short-term and long-term financing and the cost of such financing. Additionally, our ability to engage in certain collateralized business activities on a cost-effective basis depends on Nexen's credit ratings. A reduction in the current rating on our debt by rating agencies, particularly a downgrade below current ratings, or a negative change in the ratings outlook could adversely affect our cost of financing and our future access to sources of liquidity and capital. In addition, changes in credit ratings may affect our ability to, and the associated costs of: i) entering into ordinary course derivative or hedging transactions and may require posting additional collateral under certain contracts; and ii) entering into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

The table below details our current credit ratings and outlooks for our senior unsecured debt issued by credit rating agencies as of December 31, 2011. A credit rating is an independent measure intended to give an indication of a company's ability to meet its financial commitments under the rated securities. Ratings are not recommendations to buy, hold or sell the debt and may be subject to revisions or withdrawal at any time by the rating agency. We believe our financial results, ample liquidity and financial flexibility continue to support our credit ratings.

| | Standard & Poor's Rating Service (S&P) | Moody's Investors Service (Moody's) | DBRS Limited (DBRS) |
|---|---|---|---|
| Senior Unsecured/Long-Term Rating | BBB- | Baa3 | BBB |
| Outlook | Stable | Negative | Stable |

S&P's credit ratings are on a long-term debt rating scale that ranges from AAA to D, representing the range from highest to lowest quality of such securities rated. 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. According to S&P's rating system, an obligation rated "BBB" exhibits 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 commitment on the obligation. Debt securities rated "BBB-" are at the lowest end of these investment grade securities.

Moody's credit ratings are on a long-term debt rating scale that ranges from Aaa to C, representing the range from highest to lowest quality of such securities rated. Moody's applies numerical modifiers 1, 2 and 3 to each generic rating classification from Aa through Caa in its long-term debt rating system. The modifier 1 indicates that the obligation 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 that generic rating category. According to the Moody's rating system, debt securities rated "Baa3" are subject to moderate credit risk, considered medium grade and may possess certain speculative characteristics. In March 2011, Moody's confirmed our senior unsecured credit rating at Baa3 with a negative outlook (previously stable). The confirmation of our rating reflects our commitment to ongoing debt reduction, while a negative outlook reflects the execution risk of reducing debt relative to production and other measures.

DBRS' credit ratings are on a long-term debt rating scale that ranges from AAA to D, representing the range from highest to lowest quality of such securities rated. Each rating category between AA and C can be modified by the designations "high" and "low", which indicate the relative standing of a rating within a particular rating category.

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The absence of either a "high" or "low" designation indicates that the rating is in the "middle" of the category. According to DBRS' rating system, long-term debt securities rated 'BBB' are of adequate credit quality. The capacity for the payment of financial obligations is considered acceptable, however, it may be vulnerable to future events.

Risks and uncertainties related to our credit ratings and their possible impacts are discussed more fully in the section titled "Risk Factors" under the section titled "A downgrade in our credit rating could increase our cost of capital and limit access to capital".

Quarterly Dividends Declared on Common Shares

| (Cdn$/share) | First Quarter | Second Quarter | Third Quarter | Fourth Quarter |
|---|---|---|---|---|
| 2011 | 0.05 | 0.05 | 0.05 | 0.05 |
| 2010 | 0.05 | 0.05 | 0.05 | 0.05 |
| 2009 | 0.05 | 0.05 | 0.05 | 0.05 |

Subject to applicable law, our board of directors determines if and when dividends are declared on our common shares. Historically, dividends have been declared quarterly and paid on the first business day of the subsequent quarter. All dividends paid to holders of common shares in 2011 have been designated as "eligible dividends" for Canadian tax purposes. This designation will apply to all such dividends paid in the future unless otherwise notified by us.

The Income Tax Act (Canada) requires us to deduct a withholding tax from all dividends remitted to non-residents. According to the Canada-US Tax Treaty, we deducted a withholding tax of 15% on dividends paid to residents of the United States, except in the case of a company that owns at least 10% of the voting stock, where the withholding tax is 5%.

MARKET FOR SECURITIES

Common Shares

Our outstanding common shares are listed and traded on the TSX and NYSE under the trading symbol "NXY". The following table provides the market price ranges and the aggregate volume of trading of the common shares on the TSX and NYSE for the periods indicated:

| | Toronto Stock Exchange Cdn$ | | | | New York Stock Exchange US$ | | | |
|---|---|---|---|---|---|---|---|---|
| 2011 | High | Low | Close | Volume | High | Low | Close | Volume |
| January | 25.33 | 21.57 | 25.15 | 34,908,743 | 25.29 | 21.71 | 25.15 | 29,041,295 |
| February | 26.62 | 22.18 | 26.51 | 45,046,740 | 27.40 | 22.47 | 27.31 | 38,605,716 |
| March | 27.11 | 23.43 | 24.17 | 42,888,514 | 27.94 | 23.97 | 24.92 | 47,347,052 |
| April | 25.03 | 21.71 | 25.03 | 31,788,860 | 26.44 | 22.65 | 26.43 | 29,210,135 |
| May | 25.47 | 21.15 | 22.35 | 34,434,065 | 26.82 | 21.60 | 23.10 | 37,620,636 |
| June | 22.52 | 19.22 | 21.74 | 35,521,436 | 23.20 | 19.43 | 22.50 | 32,478,593 |
| July | 23.67 | 20.97 | 22.29 | 26,877,468 | 24.99 | 21.76 | 23.30 | 27,571,915 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| August | 22.21 | 18.26 | 20.92 | 33,056,247 | 23.81 | 18.34 | 21.35 | 36,920,313 |
| September | 21.07 | 15.67 | 16.30 | 36,436,039 | 21.62 | 15.13 | 15.49 | 29,597,283 |
| October | 17.35 | 14.75 | 16.93 | 36,467,835 | 17.35 | 13.88 | 16.98 | 36,388,215 |
| November | 18.00 | 14.81 | 16.99 | 27,451,704 | 17.72 | 14.23 | 16.57 | 25,294,949 |
| December | 17.04 | 14.20 | 16.21 | 46,418,240 | 16.74 | 13.63 | 15.91 | 19,665,962 |

Subordinated Notes

Our 7.35% subordinated notes due 2043 (7.35% Notes) are listed and traded on the TSX under the trading symbol “NXY.PR.U” and on the NYSE under the trading symbol “NXYPRB”. The following table provides the market price ranges and the aggregate volume of trading of the 7.35% Notes on the TSX and NYSE for the periods indicated:

| | Toronto Stock Exchange Cdn$ | | | | NewYork Stock Exchange US$ | | | |
|---|---|---|---|---|---|---|---|---|
| 2011 | High | Low | Close | Volume | High | Low | Close | Volume |
| January | 25.74 | 25.11 | 25.20 | 24,115 | 25.42 | 24.99 | 25.14 | 40,027 |
| February | 25.88 | 25.06 | 25.50 | 17,873 | 25.35 | 25.05 | 25.34 | 33,073 |
| March | 25.88 | 25.00 | 25.48 | 23,356 | 25.50 | 25.16 | 25.35 | 38,213 |
| April | 25.70 | 25.05 | 25.20 | 25,896 | 25.59 | 25.04 | 25.34 | 56,528 |
| May | 25.60 | 25.20 | 25.60 | 9,996 | 25.49 | 25.20 | 25.36 | 23,267 |
| June | 25.74 | 25.20 | 25.60 | 14,945 | 25.55 | 25.20 | 25.44 | 31,290 |
| July | 25.88 | 25.20 | 25.50 | 17,335 | 25.65 | 25.14 | 25.15 | 27,352 |
| August | 25.50 | 23.80 | 25.40 | 33,625 | 25.41 | 22.38 | 25.22 | 34,894 |
| September | 25.47 | 25.03 | 25.20 | 9,641 | 25.90 | 25.11 | 25.35 | 28,499 |
| October | 25.75 | 24.76 | 25.40 | 9,978 | 25.70 | 24.45 | 25.45 | 134,408 |
| November | 25.63 | 25.03 | 25.49 | 4,528 | 25.34 | 25.00 | 25.29 | 35,221 |
| December | 25.83 | 25.21 | 25.60 | 7,010 | 25.60 | 25.09 | 25.58 | 34,412 |

Prior Sales

For information in respect of share issuances related to the exercise of stock options and our dividend reinvestment plan, see Note 18 to our annual Consolidated Financial Statements for the year ended December 31, 2011, which are incorporated by reference into this AIF.

DIRECTORS

According to our Articles, Nexen must have between three and 15 directors. Our By-Laws provide that directors will be elected at the annual general meeting (AGM) each year and will hold office until the following AGM when their successors are elected. The following is a list of our directors as at February 15, 2012.

| Name (Age) | Residence | Principal Occupation1 | Other Directorships | Nexen Director Since |
|---|---|---|---|---|
| William B. Berry3 (59) | Houston,Texas, United States | Retired oil and gas executive<br><br>Formerly: Executive Vice President of ConocoPhillips | Teekay Corporation<br>Willbros Group, Inc. | 2008 |
| Robert G. Bertram3 (67) | Aurora, Ontario, Canada | Retired pension investment executive<br><br>Formerly: Executive Vice President of OntarioTeachers' Pension Plan Board | Strathbridge Asset Management Inc.2 | 2009 |
| Thomas W. Ebbern (53) | Calgary, Alberta, Canada | CFO of Northwest Upgrading Inc.<br><br>Formerly: Managing director of Macquarie Capital Markets Canada Ltd. | — | 2011 |
| Dennis G. Flanagan3 (72) | Calgary, Alberta, Canada | Retired oil and gas executive | Canexus (Chair) | 2000 |
| S. Barry Jackson (59) | Calgary, Alberta, Canada | Retired oil and gas executive | TransCanada Corporation (Chair)<br>TransCanada PipeLines Limited (Chair)<br>WestJet Airlines Ltd. | 2001 |
| Kevin J. Jenkins (55) | Windsor, Berkshire, United Kingdom | President and Chief Executive Officer of World Vision International<br><br>Formerly: Managing Director of TriWest Capital Partners | — | 1996 |
| A. Anne McLellan, P.C., O.C. (61) | Edmonton, Alberta, | Counsel with Bennett Jones LLP, Barristers and | Agrium Inc.<br>Cameco Corporation | 2006 |

| | | | | |
|---|---|---|---|---|
| | Canada | Solicitors, and Distinguished Scholar in Residence at the University of Alberta in the Institute for United States Policy Studies<br><br>Formerly: Member of Parliament for Edmonton Centre, Deputy Prime Minister, Minister of Public Safety and Emergency Preparedness and Minister of Health | | |
| Eric P. Newell, O.C. (67) | Edmonton, Alberta, Canada | Retired oil executive | — | 2004 |
| Thomas C. O'Neill3 (66) | Toronto, Ontario, Canada | Retired chartered accountant | Adecco S.A.<br>BCE Inc. (Chair)<br>Loblaw Companies Limited<br>The Bank of Nova Scotia | 2002 |
| Kevin J. Reinhart4 (53) | Calgary, Alberta, Canada | Interim President and CEO of Nexen<br><br>Formerly: Executive Vice President and CFO; Senior VP and CFO; Senior VP, Corporate Planning and Business Development; VP, Corporate Planning and Business Development of Nexen | — | 2012 |
| Francis M. Saville, Q.C. (73) | Calgary, Alberta, Canada | Chair of Nexen<br><br>Formerly: Counsel with Fraser Milner Casgrain LLP, Barristers and Solicitors | — | 1994 |
| Arthur R.A. Scace C.M., Q.C.3 (73) | Toronto, Ontario, Canada | Retired lawyer<br><br>Formerly: Partner and Chair of McCarthy Tetrault and Chair of Bank of Nova Scotia | Fiera-Sceptre Inc.<br>WestJet Airlines Ltd. | 2011 |
| John M. Willson (72) | Vancouver, British Columbia, Canada | Retired mining executive | — | 1996 |

| | | | | |
|---|---|---|---|---|
| Victor J. Zaleschuk5 (68) | Calgary, Alberta, Canada | Retired oil and gas executive | Agrium Inc.<br>Cameco Corporation (Chair) | 1997 |

1 Current and within the past five years.

2 An investment management fund organization managing a series of closed-end funds listed on the TSX. Mr. Bertram is a board member and participates in the audit committee function for five exchange-listed funds.

3 Audit committee financial expert under US regulatory requirements.

4 Upon the departure of Mr. Romanow, President and CEO, Mr. Reinhart was appointed to the board on January 10, 2012.

5 Mr. Zaleschuk was President and CEO of Nexen from 1997 to 2001.

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Previous Directorships

The following table details the previous directorships held by our directors over the last five years at public and registered investment companies.

| Name | Company |
|---|---|
| Flanagan | NAL Oil and GasTrust |
| Jackson | Cordero Energy Inc. |
| Newell | Canfor Corporation |
| Reinhart | Canexus |
| Scace | Garbell Holdings Limited, Gerdau AmeriSteel Corporation, Sceptre Investment Counsel Limited,The Bank of Nova Scotia |
| Willson | Finning International Inc., Pan American Silver Corp., Harry Winston Diamond Corp. |

Conflicts of Interest

As described on page 55, certain of Nexen's directors are associated with other issuers engaged in the oil and gas industry and the interests of these directors could come into conflict with the interests they hold in these other issuers. In the event of a conflict of interest, Canadian legislation requires the director to disclose to Nexen the nature and extent of any interest they have in a material contract or material transaction, if the director is a party to the contract or transaction in question, if the director is a director or an officer of a party to the contract or transaction in question or has a material interest in a party to the contract or transaction. Nexen's Integrity Guide also sets forth a detailed process for dealing with conflicts of interest.

Board Committees

| | Committees (Number of Members) | | | | | |
|---|---|---|---|---|---|---|
| | Audit[1,2] (6) | Compensation[1] (5) | Governance[1] (5) | Finance[1] (6) | HSE & SR[1] (5) | Reserves[1] (5) |
| Management Director–Not Independent | | | | | | |
| Kevin J. Reinhart | | | | | | |
| Independent Outside Directors | | | | | | |
| William B. Berry[3] | √ | √ | | | | Chair |
| Robert G. Bertram[3, 4] | √ | | √ | √ | | |
| Thomas W. Ebbern | √ | | | √ | | √ |
| Dennis G. Flanagan[3] | √ | | | √ | | |
| S. Barry Jackson | | √ | Chair | √ | | |
| Kevin J. Jenkins | | Chair | √ | | | |
| A. Anne McLellan, P.C., O.C. | | | | √ | √ | |
| Eric P. Newell, O.C. | | | | | Chair | √ |

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|---|---|---|---|---|---|---|
| Thomas C. O’Neill[3] | Chair | √ | | | | |
| Francis M. Saville, Q.C. | | | √ | | √ | |
| Arthur R.A. Scace, C.M., Q.C. [3] | √ | √ | √ | | | |
| John M. Willson | | | | | √ | √ |
| Victor J. Zaleschuk | | | | Chair | √ | √ |

1 All members are independent. All Audit Committee members are independent and financially literate under additional regulatory requirements applicable to them.

2 Experience of the members of the Audit Committee that indicates an understanding of the accounting principles we use to prepare our financial statements is shown on page 57.

3 Audit Committee financial expert under US regulatory requirements.

4 Mr. Bertram is a board member and participates in the audit committee function for five exchange-listed funds. The funds are related managed entities and limited in business purpose as investment funds. They are restricted to a mandate of a limited number of specific securities and dealt with as a group, making preparation and review time significantly less than would be associated with a single full-operating business. The board has considered and determined that Mr. Bertram’s participation in these funds does not impede his ability to fully carry out his duties as a director and committee member of Nexen.

# APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

## AUDIT COMMITTEE INFORMATION

Each member of the Audit Committee has a thorough understanding of accounting principles and has the ability to assess the application of accounting principles in connection with the preparation of financial statements and the accounting for estimates, accruals and reserves. Audit Committee members have an understanding of internal controls and procedures for financial reporting and have experience preparing, auditing, analyzing or evaluating financial statements or actively supervising individuals engaged in such activities. Over the year, there were changes in Audit Committee membership. Mr. Ebbern and Mr. Scace joined the committee in October 2011 and Mr. Jenkins and Mr. Newell left the committee in January 2012. Below is a description of each current Audit Committee member's education and experience.

### Audit Committee Education and Experience

| Name | Experience |
|---|---|
| Berry | William Berry is a retired oil and gas executive. From 2003 to 2008, he was Executive Vice President of ConocoPhillips. He also held other senior executive positions with Phillips Petroleum Co., including Senior Vice President, Exploration and Production. His career in the oil and gas industry began in 1976 and includes experience working in Africa, the North Sea, Asia, Russia, the Caspian Sea and North America.<br><br>Mr. Berry has Bachelor and Masters of Science degrees in Petroleum Engineering from Mississippi State University. He was responsible for understanding the financial reporting of exploration and production at ConocoPhillips and finance managers reporting directly to him on a functional basis. He held various management roles, including Manager, Corporate Planning and Budgeting. |
| Bertram | Robert Bertram is a retired pension investment executive. He was the Executive Vice President of Ontario Teachers' Pension Plan Board (Teachers) from 1990 to 2008. He led Teachers' investment program and oversaw the pension fund's growth from $19 billion when it was established in 1990 to $108.5 billion. Prior to that, he spent 18 years at Telus Corporation, formerly Alberta Government Telephones, where his responsibilities included investment management, capital procurement, corporate risk management, tax and compliance. Before leaving Telus, he was Assistant Vice President and Treasurer.<br><br>Mr. Bertram has a Bachelor of Arts degree in history from the University of Calgary and a Master of Business Administration from the University of Alberta. He is a Chartered Financial Analyst (CFA) charter holder. |
| Ebbern | Tom Ebbern is the Chief Financial Officer of North West Upgrading Inc. He was formerly Managing Director, Investment Banking, of Macquarie Capital Markets Canada Ltd., a subsidiary of Macquarie Group Limited. Prior to that, he was Managing Director of Tristone Capital Inc., an energy advisory firm that was acquired by Macquarie. Mr. Ebbern's various positions have provided him with years of energy experience in exploration, business development, and oil and gas investment banking and research. |

| | |
|---|---|
| | Mr. Ebbern has a Bachelor of Science degree in Geological Engineering from Queen's University and a Masters of Business Administration degree from the Richard Ivey School of Business at the University of Western Ontario. |
| Flanagan | Dennis Flanagan is a retired oil and gas executive. He worked in the oil and gas industry for more than 40 years with Ranger Oil Limited (Ranger) and ELAN Energy Inc. (ELAN). Most recently, Mr. Flanagan was Executive Chair of ELAN until it was bought by Ranger in 1997. He was involved in all phases of exploration and development in Canada, the US and the UK North Sea.<br><br>Mr. Flanagan completed the Registered Industrial and Cost Accountant program, the predecessor to the Certified Management Accountant program, in 1967. He worked in various accounting and management positions at Ranger, notably as the Chief Financial Officer (CFO) and Executive Vice President. |
| O'Neill | Tom O'Neill is the retired Chair of PwC Consulting. He was formerly CEO of PwC Consulting; COO of PricewaterhouseCoopers LLP, Global; CEO of PricewaterhouseCoopers LLP, Canada and Chair and CEO of Price Waterhouse Canada. He worked in Brussels in 1975 to broaden his international experience and from 1975 to 1985 was lead partner for numerous multinational companies, specializing in dual Canadian and US listed companies.<br><br>Mr. O'Neill has a Bachelor of Commerce Degree from Queen's University. He received his Chartered Accountant designation in 1970 and was made a Fellow (FCA) of the Institute of Chartered Accountants of Ontario in 1988. Mr. O'Neill lectured on Political Economics at the University of Toronto, taught courses in commerce and finance, and has been actively involved in a number of associations, including various committees of the Canadian and Ontario Institutes of Chartered Accountants. |
| Scace | Arthur Scace is a retired lawyer. He was formerly Partner and Chair of McCarthy Tetrault LLP, Barristers and Solicitors in Toronto. He was also formerly Chair of The Bank of Nova Scotia. Specializing in tax law, Mr. Scace has provided advice in many domestic and international commercial transactions, co-authored The Income Tax Law of Canada, headed up tax law courses and lectured at various schools and universities.<br><br>Mr. Scace holds his Bachelor of Arts degrees from the University of Toronto and Oxford University, a Master of Arts degree from Harvard University and a Bachelor of Laws degree from Osgoode Hall Law School. |

# APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

The Audit Committee mandate is included in Appendix A of this AIF.

All Committee mandates, including those for the Audit, Compensation and Governance Committees, our code of ethics and our corporate governance policy and categorical standards are available at www.nexeninc.com. Shareholders wishing to receive a copy of these documents may write to the Governance Office by mail at Nexen Inc., 801-7th Avenue SW, Calgary, Alberta, Canada T2P 3P7, Attention: Governance Office or by email at governance@nexeninc.com.

## INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS (IRCA) FEES

### Pre-Approval Policies and Procedures

Nexen has adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by the IRCA. The Audit Committee approves all services provided by the IRCA and the related fees. The services are sufficiently detailed to ensure that: i) the Audit Committee understands the services it is being asked to pre-approve; and ii) Nexen's management does not need to make a judgement as to whether a proposed service fits within the pre-approved services. The pre-approval policies are further described in the Audit Committee mandate included in Appendix A of this AIF.

IRCA services that arise that were not pre-approved by the Audit Committee must be pre-approved by the Audit Committee chair between committee meetings. The Audit Committee is informed of the services at the following meeting.

Nexen did not rely on the de minimus exemption provided by Section (c)(7)(i)(C) of Rule 2-01 of SEC Regulation S-X in either 2011 or 2010.

### IRCA Fees Billed

The following table provides information about the fees billed to Nexen for professional services rendered by the IRCA during 2011 and 2010.

| Type of Fee | Billed in 2010 | Billed in 2011[1] | Percentage of Total Fees Billed in 2011 |
|---|---|---|---|
| Audit Fees[2] | 3,252,415 | 2,678,492 | 67% |
| Audit-Related Fees[3] | 1,727,203 | 702,332 | 17% |
| Tax Fees[4] | 59,251 | 69,291 | 2% |
| All Other Fees[5] | 163,975 | 555,078 | 14% |
| Total Annual Fees | 5,202,844 | 4,005,193 | 100% |

1 Fees billed in 2011 exclude fees related to Canexus as our remaining interest was sold in early 2011.

2 Audit fees were paid to the IRCA for the audit of annual financial statements or services provided in connection with statutory and regulatory filings or engagements.

3 Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of subsidiary financial statements and are not reported as Audit Fees.

4 Tax fees were paid to the IRCA for tax compliance services and tax-related consultation.

5 Other fees were paid to the IRCA for subscriptions to auditor-provided and supported tools.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

EXECUTIVE OFFICERS

The board determines the term of office for each executive officer. Mr. Marvin F. Romanow, President and CEO, and Mr. Gary H. Nieuwenburg, Executive VP, Canada, both of which were executive officers as at December 31, 2011, left Nexen on January 9, 2012. Below are Nexen's executive officers as at February 15, 2012, including prior offices and non-executive positions for each of them during the past five years. Start dates with Nexen are indicated for officer positions.

| Officer (Age) | Residence | Current and Past Position(s) | Effective Date of Current Position | Executive Officer Since |
|---|---|---|---|---|
| Kevin J. Reinhart (53) | Calgary, Alberta, Canada | Interim President and CEO and a director.<br><br>Formerly: Executive VP and CFO since April 27, 2010; Senior VP and CFO since January 1, 2009; Senior VP, Corporate Planning and Business Development since November 1, 2007; VP, Corporate Planning and Business Development since July 11, 2002. | January 9, 2012 | 1994 |
| Una M. Power (47) | Calgary, Alberta, Canada | Interim CFO and Senior VP, Corporate Planning and Business Development.<br><br>Formerly: Senior VP Corporate Planning and Business Development since April 27, 2010; VP, Corporate Planning and Business Development since January 16, 2009;Treasurer since July 11, 2002. | January 9, 2012 | 1998 |
| Catherine J. Hughes (49) | Calgary, Alberta, Canada | Executive Vice President, International Oil and Gas.<br><br>Formerly: Interim Executive Vice President, International and VP Operational Services and Technology since | January 23, 2012 | 2010 |

| | | | | |
|---|---|---|---|---|
| | | November 28, 2011; VP, Operational Services,Technology and Human Resources since February 17, 2010; Division VP, Operational Services,Technology and Human Resources since December 1, 2009; Division VP, Operational Services andTechnology since September 1, 2009; VP Oil Sands at Husky Oil Operations Ltd. since October 1, 2007; VP Exploration and Production Services at Husky Oil Operations Ltd. since September 1, 2005. | | |
| James T. Arnold (52) | Calgary, Alberta, Canada | Senior VP, Oil Sands.<br><br>Formerly: Senior VP, Synthetic Crude since July 16, 2009; Division VP Operations and Projects, Synthetic Oil since February 1, 2009; Chief Operating Officer at OPTI Canada Inc. since October 13, 2005. | February 15, 2012 | 2009 |
| Ronald W. Bailey (47) | Calgary, Alberta, Canada | Senior Vice President, Canada<br><br>Formerly: Division VP, Natural Gas-Canada since November 1, 2011; division VP, Shale Gas-Canada since December 1, 2010; GM, Gas-Shale Exploration and Development since February 1, 2009; GM, Gas-CBM/Conventional since August 1, 2005. | February 15, 2012 | 2012 |
| Alan O'Brien (54) | Calgary, Alberta, Canada | Senior VP, General Counsel and Secretary.<br><br>Formerly: Interim Senior VP, General Counsel and Secretary since December 2, 2011; Division Vice President, Chief Legal Counsel, International since November 30, 2010; | January 23, 2012 | 2012 |

| | | | | |
|---|---|---|---|---|
| | | Division Vice President, Chief Legal Counsel, NPUL since July 1, 2006. | | |
| Kim D. McKenzie (63) | Calgary, Alberta, Canada | VP and Chief Information Officer.<br><br>Formerly: Division VP, InformationTechnology since January 1, 1992. | November 1, 2007 | 2007 |
| Kevin J. McLachlan (48) | Calgary, Alberta, Canada | VP, Global Exploration.<br><br>Formerly: Division VP, Global Exploration since July 1, 2009; Division VP, International Exploration since August 1, 2008; Manager, Exploration, since January 1, 2006; East Coast Exploration Manager at Imperial Oil Resources since April 1, 2005. | February 17, 2010 | 2010 |
| Quinn E. Wilson (42) | Calgary, Alberta, Canada | VP, Human Resources and Corporate Services.<br><br>Formerly: Division VP, Global Human Resources since January 1, 2011; Division VP Human Resources, International since August 16, 2010; VP, HR Global Business Partners at Flextronics since August 1, 2007; HR Business Partner—Infrastructure Segment at Flextronics since September 1, 2006. | November 28, 2011 | 2011 |
| Brendon T. Muller (43) | Calgary, Alberta, Canada | Controller and VP, Insurance.<br><br>Formerly: Controller since April 9, 2007; Manager, Corporate External Reporting since November 1, 2003. | April 27, 2011 | 2007 |
| J. Michael Backus (41) | Calgary, Alberta, Canada | Treasurer.<br><br>Formerly: Manager, Planning, Synthetic Crude since January 1, 2009; Project | February 16, 2009 | 2009 |

| | |
|---|---|
| | Planner—Phase 2 Long Lake, Synthetic Crude since April 1, 2005. |

## OTHER

### Legal Proceedings and Regulatory Actions

Nexen is party to various legal proceedings, both as a claimant and as a defendant, the ultimate results of which cannot be ascertained at this time. Management is of the opinion that any amounts awarded to us or assessed against us would not have a material effect on our consolidated financial position or results of operations. In any event, there are no legal proceedings to which we are a party or which our property is the subject of, nor are there any proceedings known by us to be contemplated that involves a claim for damages exceeding 10% of our current assets. We believe we have made adequate provisions for such lawsuits and claims.

Certain of our US oil and gas operations have received, over the years, notices and demands from the US EPA, state environmental agencies and certain third parties for certain sites seeking to require investigation and remediation under federal or state environmental statutes. In addition, notices, demands and lawsuits have been received for certain sites related to historical operations and activities in the US. Although no assurances can be made, we believe that certain assumption and indemnification agreements protect our US operations from any present or future material liabilities that may arise from these particular sites.

During the year ended December 31, 2011, there have been no: i) penalties or sanctions imposed against Nexen or its subsidiaries by a court relating to securities legislation or by a securities regulatory authority; or ii) settlement agreements entered into by Nexen or its subsidiaries before a court relating to securities legislation or with a securities regulatory authority. There have been no penalties or sanctions imposed by a court or regulatory body relating to any other legislation against Nexen or its subsidiaries that would likely be considered important to a reasonable investor in making an investment decision.

### Interests of Management and Others in Material Transactions

No director or executive officer of Nexen or its subsidiaries, or any person or company that beneficially owns or controls or directs, directly or indirectly, more than 10% of Nexen's outstanding voting securities or any associate or affiliate of these persons currently has, or has had, any material interests in any transaction or any proposed transaction that has materially affected or is reasonably expected to materially affect Nexen or any of Nexen's subsidiaries, within the three most recently completed financial years or during the current financial year.

### Shareholdings of Directors and Executive Officers

At December 31, 2011, Nexen's directors and executive officers as a group beneficially own, directly or indirectly, or exercise control or direction over, less than 1% of Nexen's issued and outstanding Common Shares.

### Cease Trade Orders, Bankruptcies, Penalties or Sanctions

As of the date of this AIF, we confirm that, to the best of our knowledge:

(a) in the last 10 years, no director or executive officer of Nexen is or has been a director, chief executive officer or chief financial officer of another company or has owned a personal holding company that:

i) was subject to a cease trade order or an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days (an order) while the director or executive officer was acting as a director, chief executive officer or chief financial officer; or

ii) was subject to an order after the director or executive officer ceased to be a director, chief executive officer or chief financial officer in the company and which resulted from an event that occurred while that person was acting in the capacity as a director, chief executive officer or chief financial officer.

(b) in the last 10 years, no director or executive officer of Nexen has been a director or executive officer of a company that became bankrupt or made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets while the director or executive officer was acting as a director or executive officer of such company or within a year of ceasing to act in that capacity;

(c) no director or executive officer of Nexen nor any personal holding company controlled by such person has become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director or executive officer; and

(d) no director or executive officer of Nexen has been subject to:

i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or

ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Transfer Agents and Trustees

In Canada, CIBC Mellon Trust Company (CIBC Mellon) is our transfer agent and registrar of the Company's common shares. Canadian Stock Transfer Company Inc. acts as the administrative agent for CIBC Mellon. They are located at:

CIBC Mellon Trust Company
c/o Canadian Stock Transfer Company Inc.
320 Bay Street
Toronto, ON M5H 4A6

In the United States, BNY Mellon Shareowner Services is our co-transfer agent of the Company's common shares. They are located at:

BNY Mellon Shareowner Services
480 Washington Blvd., 27th Fl.
Jersey City, NJ 07310

Deutsche Bank Trust Company Americas, 60 Wall Street, 27th Floor, Mailstop NYC 60-2710, New York, New York 10005-2858, acts as trustee for the 7.35% Notes listed on the TSX and NYSE.

Material Contracts

During the year ended December 31, 2011, Nexen did not enter into any material contracts, and there are no material contracts still in effect, other than contracts entered into in the ordinary course of business.

Interest of Experts

Deloitte & Touche LLP is our registered independent chartered accountant and has advised Nexen's Audit Committee that they are independent with respect to Nexen within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and the rules and standards of the US Public Company Accounting Oversight Board and the securities laws and regulations administered by the SEC.

Information related to reserves in this AIF was reviewed by McDaniel & Associates Consultants Ltd., Ryder Scott Company LP and DeGolyer and MacNaughton, each of which is an independent qualified reserves evaluator.

As of the date hereof, none of the partners, principals, employees or consultants of McDaniel & Associates Consultants Ltd., Ryder Scott Company LP or DeGolyer and MacNaughton, through registered or beneficial interests, directly or indirectly, held, or are entitled to receive more than 1% of any class of Nexen's outstanding securities, including the securities of our associates and affiliates.

The information relating to the Company's NI 51-101 reserves as at December 31, 2011 incorporated by reference in this AIF has been compiled by the Company based on the report dated February 15, 2012 prepared by Mr. Ian R. McDonald, an employee of Nexen, in his capacity as the Company's Internal Qualified Reserves Evaluator. Mr. McDonald beneficially owns, directly or indirectly, less than 1% of any class of the Company's securities.

Additional Information

Nexen is a Canadian issuer that is registered with the Canadian securities commissions and the SEC and trades on both the TSX and NYSE. Additional information relating to the Company can be found on the SEDAR website at www.sedar.com and on EDGAR at www.sec.gov.

Additional information including directors' and officers' remuneration and indebtedness, director nominees standing for re-election, principal holders of the Company's securities, and securities authorised for issuance under the Company's equity compensation plans, is contained in the Company's Proxy Circular for the 2012 Annual General Meeting of Shareholders.

Additional financial information is provided in our MD&A and Consolidated Financial Statements for the most recently completed financial year.

Copies of our annual report may be obtained free of charge from Nexen's website at www.nexeninc.com or upon request from:

Investor Relations
Nexen Inc.
701 8th Avenue S.W.
Calgary, Alberta T2P 3P7
(403) 699-5454

Information located on or accessible through Nexen's website does not form part of this AIF and is not incorporated by reference herein, unless specifically otherwise stated.

APPENDIX A — AUDIT AND CONDUCT REVIEW COMMITTEE MANDATE

Audit and Conduct Review Committee Mandate

The Audit and Conduct Review Committee (Committee) of the board of directors (board) of Nexen Inc. (Nexen) has the oversight responsibility and specific duties described below.

COMPOSITION

The Committee will be comprised of at least three directors. All Committee members will be independent under the Categorical Standards for Director Independence (Categorical Standards) adopted by the board and applicable law. Any Committee member who, for any reason, is no longer independent under the Categorical Standards or applicable law immediately ceases to be a Committee member.

All Committee members will be "financially literate" under the definition adopted by the board. At least one Committee member shall be designated as an "audit committee financial expert" under applicable law.

Committee members may not serve on the audit committees of more than two additional public companies without the approval of the board.

Committee members will be appointed and removed by the board. The Committee Chair will be appointed by the board.

RESPONSIBILITY

The Committee's primary purpose is to assist the board in fulfilling its oversight responsibilities with respect to (i) the integrity of annual and quarterly financial statements to be provided to shareholders and regulatory bodies; (ii) compliance with accounting and finance based legal and regulatory requirements; (iii) the independent auditor's qualifications and independence; (iv) the system of internal accounting and financial reporting controls that Management has established; (v) performance of the internal and external audit process and of the independent auditor; and, (vi) implementation and effectiveness of How We Work: Our Integrity Guide (Our Integrity Guide), which constitutes our code of ethics and the compliance programs.

SPECIFIC DUTIES

The Committee will:

Audit and Conduct Review Leadership

1. Have a clear understanding with the independent auditor that it must maintain an open and transparent relationship with the Committee, and that the ultimate accountability of the independent auditor is to the Committee, as representatives of the shareholders.

2. Provide an avenue for communication between each of internal audit (Corporate Audit), the independent auditor, financial and senior Management and the board.

3. Review and, in the Committee's discretion, approve and recommend to the board for consideration Our Integrity Guide, including procedures for (i) the receipt, retention, and treatment of complaints received by Nexen regarding accounting, internal accounting and financial reporting controls, or auditing matters; (ii) the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters; and, (iii) addressing a reporting attorney's report of a material breach of securities law, material breach of fiduciary duty or similar material violation.

4. Take all reasonable steps to oversee the implementation of Our Integrity Guide, including reviewing with Management Our Integrity Guide and the implementation and effectiveness of compliance programs under Our Integrity Guide.

5. Take all reasonable steps to oversee conduct review by receiving an annual report summarizing the statements of compliance completed by employees pursuant to the Integrity Program, the Conflict of Interest Policy and the Prevention of Improper Payments Policy and make any resulting inquiries the Committee decides is needed.

6. With the board and the board Chair, respond to potential conflict of interest situations.

Independent Auditor Qualifications and Selection

7. Subject to required shareholder approval of auditors, be solely responsible for selecting, retaining, compensating, overseeing and, where necessary, terminating the independent auditor. The independent auditor will be a "Registered Public Accounting Firm" and a "Participating Audit Firm", each as defined under applicable law and will report directly to the Committee. The Committee is entitled to adequate funding from Nexen to compensate the independent auditor for completing an audit and audit report or performing other audit, review or attest services.

8. Evaluate the independent auditor's qualifications, performance and independence. As part of that evaluation, at least annually review a report by the independent auditor describing: the firm's (auditor's) internal quality control systems and procedures; any material issues, defects, restrictions or sanctions raised or imposed by the most recent internal quality control review, or peer review, of the firm, or by any inquiry or

investigation by governmental or professional authorities or board, within the preceding five years, respecting one or more independent audits carried out by the firm or otherwise arising, and any steps taken to deal with any such issues, defects, restrictions or sanctions; and, (to assess the auditor's independence) all relationships between the independent auditor and Nexen. Take all reasonable steps to satisfy itself that the independent auditor does not provide non-audit services that would disqualify it as independent under applicable law.

9. Review the experience and qualifications of the senior members of the independent audit team and the quality control procedures of the independent auditor. Take all reasonable steps to satisfy itself that the lead audit partner of the independent auditor is replaced periodically, according to applicable law. Take all reasonable steps to satisfy itself of the continuing independence of the independent audit firm. Present the Committee's conclusions on auditor independence to the board.

10. Recommend guidelines for Nexen's hiring of partners and employees and former partners and employees of the current and any former independent auditor who were engaged on Nexen's account to the board for consideration.

Independent Audit Process

11. Pre-approve all audit services (which may include comfort letters in connection with securities underwritings). In the discretion of the Committee, annually delegate to the Committee Chair the authority to grant pre-approvals for certain audit services to expedite the hiring of the independent auditor for minor, time-sensitive audit services provided that those pre-approvals are presented in writing to the Committee at the next regularly scheduled meeting. The Committee Chair's pre-approval authority is limited to audit services required to start before the next regularly scheduled Committee meeting. The Committee Chair will not pre-approve audit services related to Nexen's integrated audit.

12. Pre-approve and disclose, as required, the retention of the independent auditor for non-audit services permitted under applicable law. In the discretion of the Committee, annually delegate to one or more of its members the authority to grant pre-approvals for non-audit services provided that those pre-approvals are presented in writing to the Committee at the next regularly scheduled meeting.

13. Meet with the independent auditor prior to the audit to review the scope and general extent of the independent auditor's annual audit including (i) the planning and staffing of the audit; and, (ii) an explanation from the independent auditor of the factors considered in determining the audit scope, including the major risk factors.

14. Require the independent auditor to provide a timely report setting out (i) all critical accounting policies, significant accounting judgments and practices to be used; (ii) all alternative treatments of financial information within Generally Accepted Accounting Principles (GAAP) that have been discussed with Management, ramifications of the use of such alternative disclosures and treatments and the treatment preferred by the independent auditor; and, (iii) other material written communications between the independent auditor and Management.

15. Take all reasonable steps to satisfy itself that officers and directors or persons acting under their direction are aware that they are prohibited from coercing, manipulating, misleading or fraudulently influencing the independent auditor when the person knew or should have known that the action could result in rendering the financial statements materially misleading.

16. Upon completion of the annual audit, review the following with Management and the independent auditor:

- The annual financial statements, including related footnotes, the MD&A (Management's Discussion and Analysis of Financial Condition and Results of Operations) and the Annual Information Form (AIF), to be included in Nexen's Annual Report filed with Canadian and US regulatory agencies.
- The significant accounting judgements and reporting principles, practices and procedures applied by Nexen in preparing its financial statements, including any newly adopted accounting policies and the reasons for their adoption.
- Any transactions accounted for by Nexen where Management has obtained opinion letters providing that hypothetical transactions accounted for in a similar manner are accounted for in accordance with GAAP (letters issued in accordance with Statement of Auditing Standards 50 - "Reports on the Application of Accounting Principles").
- The results of the combined audit of the financial statements and internal control over financial reporting; the related audit reports on the financial statements and internal control over financial reporting; and, whether any limitations were placed on the scope or nature of the audit procedures.
- Significant changes to the audit plan, if any, and any serious disputes or difficulties with Management encountered during the audit, including any problems or disagreements with Management

which, if not satisfactorily resolved, would have caused the independent auditor to issue a non standard report on Nexen's financial statements.

- The co-operation received by the independent auditor during its audit, including access to all requested records, data and information.
- Any other matters not described above that are required to be communicated by the independent auditor to the Committee pursuant to auditing standards, rules or regulations in effect at the time.

Risk Management

17. Discuss guidelines and policies with respect to risk assessment and risk management, including the processes Management uses to assess and manage Nexen's risk. Receive reports from Management and the Finance Committee with respect to risk assessment, risk management and major financial risk exposures. Discuss major financial risk exposures and steps Management has taken to monitor and manage such exposures.

Financial Statements and Disclosure

18. At least annually, as part of the review of the annual or quarterly financial statements, receive an oral report from Nexen's general counsel concerning legal and regulatory matters that may have a material impact on the financial statements.

19. Based on discussions with Management and the independent auditor, in the Committee's discretion, recommend to the board whether the annual financial statements should be approved for inclusion in Nexen's Annual Report filed with Canadian and US regulatory agencies.

20. Review with Management and the independent auditor the quarterly financial statements and MD&A and, subject to delegation by the board to the Committee and in the Committee's discretion, approve and/or recommend to the board for consideration the quarterly results, financial statements, MD&A, related reports and all earnings news releases prior to filing them with or furnishing them to the applicable securities regulators and prior to any public announcement of financial results for the periods covered, including the results of the independent auditor's reviews of the quarterly financial statements, significant adjustments, new accounting policies, any disagreements between the independent auditor and Management and the impact on the financial statements of significant events, transactions or changes in accounting principles or estimates that potentially affect the quality of financial reporting.

21. Review the general types and presentation format of information that it is appropriate for Nexen to disclose in quarterly or annual earnings news releases and annual cashflow or production guidance. Annual production and cashflow guidance is approved through the board's approval of the Annual Operating Plan. If such guidance is required to be updated during the year, the Committee Chair shall review and approve the updates and report any such change to the Committee at the next Committee meeting.

22. Receive reports, from time to time, as required, from the Chair or other representative of each of the Finance Committee and the Reserves Review Committee and discuss with them issues of relevance to both the Committee and each of the Finance Committee and the Reserves Review Committee.

Internal Control Process

23. Review with Management, Corporate Audit and the independent auditor, Nexen’s internal control over financial reporting, any significant deficiencies or material weaknesses in their design or operation, any proposed major changes to them and any fraud involving Management or other employees who have a significant role in Nexen’s internal control over financial reporting.

24. Review the independent auditor’s annual attestation of the internal control over financial reporting structure and procedures.

25. Review the performance and independence of the Corporate Audit function and whether Corporate Audit has had full access to Nexen’s books, records and personnel.

26. Review and approve the proposed annual Corporate Audit Plan including assessment of major risks, areas of focus, responsibilities and objectives, and staffing.

27. Receive periodic reports from Corporate Audit addressing (i) progress on the Corporate Audit Plan, including any significant changes to it; (ii) significant internal audit findings, including issues as to the adequacy of internal control over financial reporting and any procedures implemented in light of significant control deficiencies; and, (iii) any significant internal fraud issues.

28. Review with Management, the Chief Financial Officer, the Chief Legal Officer, Corporate Audit and the independent auditor the methods used to establish and monitor Nexen’s policies with respect to unethical or illegal activities by employees that may have a material impact on the financial statements.

29. Meet with Management, Corporate Audit and the independent auditor to discuss any relevant significant recommendations that the independent auditor may have, particularly those characterized as “material” or “serious”. (Typically, such recommendations will be presented by the independent auditor in the form of a Letter of Comments and Recommendations to

the Committee.) Review responses of Management to the Letter of Comments and Recommendations from the independent auditor and receive follow up reports on action taken concerning the recommendations.

30. Receive a report, at least annually, from the Reserves Review Committee on Nexen's oil and gas reserves, and on the findings of any independent qualified reserves consultants.

31. Review any appointment or dismissal of the senior internal audit executive (VP, Corporate Audit).

32. Review with Management and the independent auditor any correspondence with regulators or government agencies and any employee complaints or published reports which raise material issues regarding Nexen's financial statements or accounting policies.

33. Review with Management and the independent auditor any off-balance sheet financing mechanisms, transactions or obligations of Nexen.

34. Regularly review with Management and the independent auditor any related party transactions.

35. Review with the independent auditor the quality of Nexen's accounting personnel. Review with Management the responsiveness of the independent auditor to Nexen's needs.

36. Receive a report, at least annually, from Management on Nexen's community investment budget and Nexen and employee donations.

Compliance

37. Prepare a letter for the annual report to shareholders and the Annual Report filed with Canadian and US regulatory agencies, disclosing whether or not, with respect to the prior fiscal year (i) Management has reviewed the audited financial statements with the Committee, including a discussion of the quality of the accounting principles as applied and significant judgments affecting Nexen's financial statements; (ii) the independent auditor has discussed with the Committee the independent auditor's judgments of the quality of those principles as applied and judgments referenced in (i) above under the circumstances; (iii) the members of the Committee have discussed among themselves, without Management or the independent auditor present, the information disclosed to the Committee described in (i) and (ii) above; and, (iv) the Committee, in reliance on the review and discussions conducted with Management and the independent auditor pursuant to (i) and (ii) above, believes that Nexen's financial statements are fairly presented in conformity with Canadian GAAP in all material respects and that any reconciliation of Nexen's financial statements to US GAAP complies with the requirements of the Securities Exchange Act of 1934 (1934 Act).

38. Receive reports, as required, from Management, Nexen's VP, Corporate Audit or, to the best of their knowledge, the independent auditor that Nexen's subsidiary / foreign affiliated entities are in conformity with applicable legal requirements and Our Integrity Guide, including disclosures of insider and affiliated party transactions.

39. Review with the independent auditor any reports required to be submitted to the Committee under Section 10A of the 1934 Act (regarding the detection of illegal acts, the identification of related party transactions and the evaluation of whether there is substantial doubt about the ability of Nexen to continue as a going concern).

Committee Reporting

40. Following each meeting of the Committee, report to the board on the activities, findings and any recommendations of the Committee.

41. Report regularly to the board and review with the board any issues that arise with respect to the quality or integrity of Nexen's financial statements, Nexen's compliance with applicable law, the performance and independence of Nexen's independent auditor, and the performance of the Corporate Audit function.

42. Annually review and approve the Committee's report for inclusion in the Proxy Circular.

43. Prepare any reports required to be prepared by the Committee under applicable law.

Committee Meetings

44. Meet at least four times annually and as many additional times as needed to carry out its duties effectively. The Committee may, on occasion and in appropriate circumstances, hold a meeting by telephone conference call.

45. Meet in separate, non-management, closed sessions with the VP, Corporate Audit at each regularly scheduled meeting.

46. Meet in separate, non-management, closed sessions with the independent auditor at each regularly scheduled meeting.

47. Meet in separate, non-management, in camera sessions at each regularly scheduled meeting.

48. Meet in separate, non-management, closed sessions with any other internal personnel or outside advisors, as needed or appropriate.

Committee Governance

49. Once or more annually, as the Corporate Governance and Nominating Committee (CGN Committee) decides, receive for consideration that Committee's evaluation of this Mandate and any recommended changes. Review and assess the CGN Committee's recommended changes and make recommendations to the board for consideration.

Advisors / Resources

50. Have the sole authority to retain, oversee, compensate and terminate independent advisors who assist the Committee in its activities.

51. Receive adequate funding from Nexen for independent advisors and ordinary administrative expenses that are needed or appropriate for the Committee to carry out its duties.

Other

52. Carry out any other appropriate duties and responsibilities assigned by the board.

53. To honour the spirit and intent of applicable law as it evolves, authority to make minor technical amendments to this Mandate is delegated to the Secretary, who will report any amendments to the CGN Committee at its next meeting.

Approved: November 28, 2011

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

APPENDIX B—RESERVES ESTIMATES AND SUPPLEMENTARY DATA UNDER SEC REQUIREMENTS

The following reserves estimates have been prepared in accordance with the requirements of the US Securities and Exchange Commission (SEC). We are providing this additional reserves disclosure to enhance comparability to non-Canadian oil and gas companies. The primary differences between NI 51-101 requirements and SEC requirements are set out under the heading "Special Note to Investors" on page 40 of this AIF.

All reserves are after royalty values unless otherwise noted.

These estimates are internally prepared. For more information on our reserves evaluation process refer to the section entitled "Basis of Reserves Estimates" on pages 21 to 22 of this AIF.

Nexen has not filed with nor included in reports to any Canadian or United States federal authority or agency, any estimates of its total proved oil or gas reserves since the beginning of 2011.

Oil and Gas Reserves Estimates

At December 31, 2011, estimated proved reserves were 980 mmboe before royalties and 900 mmboe after royalties. Our probable estimated reserves were 1,315 mmboe before royalties and 1,122 mmboe after royalties. The following is a summary of our proved and probable reserves as at December 31, 2011:

| | Before Royalties | | | | After Royalties | | | |
|---|---|---|---|---|---|---|---|---|
| | Synthetic Oil (mmbbls) | Bitumen (mmbbls) | Oil (mmbbls) | Gas (bcf) | Synthetic Oil (mmbbls) | Bitumen (mmbbls) | Oil (mmbbls) | Gas (bcf) |
| Developed | 228 | — | 183 | 352 | 200 | — | 179 | 328 |
| Undeveloped | 415 | — | 68 | 158 | 377 | — | 64 | 154 |
| Total Proved | 643 | — | 251 | 510 | 577 | — | 243 | 482 |
| Developed | 10 | — | 83 | 160 | 7 | — | 80 | 148 |
| Undeveloped | 267 | 661 | 118 | 893 | 226 | 540 | 102 | 848 |
| Total Probable | 277 | 661 | 201 | 1,053 | 233 | 540 | 182 | 996 |

Over 60% of our reserves relate to our Canadian oil sands properties. The synthetic oil reserves relate to our Long Lake and Kinosis K1A projects and our non-operated interest in Syncrude. These reserves reflect bitumen which is upgraded on site into synthetic oil and are expected to be developed and produced through the existing facilities over the next 50 years. The bitumen reserves relate to our Kinosis and Hangingstone properties, where we have not yet committed to build upgrading facilities at this time. Project planning at Kinosis and Hangingstone is underway.

Our oil sands reserves estimates and development plans are continually evolving to reflect production performance and other information. This year, as part of our reserves process, we revised our expectations of bitumen recoverability from our oil sands reservoirs. Our previous interpretation under-estimated the productivity of thick clean sand, and over-estimated the productivity of poorer quality sand and the effects of shale. As a result, in the high-quality areas, we increased bitumen recovery factors. Conversely, we reduced our reserve estimates on the poor quality reservoir and removed proved acreage in lower quality areas that we are less likely to develop. This revised understanding of the reservoir productivity caused us to change our resource development strategy to fill the Long

Lake upgrader. Our plans now include accelerating development of the Kinosis K1A lands, a subset of the original Kinosis lease, where extensive core hole testing indicates higher quality resource. These lands can be brought on-stream sooner than other Long Lake areas as we are further advanced in the planning process.

The remainder of our reserves are widely distributed throughout our oil and gas properties around the world in our offshore oil and gas operations in the UK North Sea, US Gulf of Mexico, Nigeria and onshore Canada and Colombia.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

Proved Reserves

In 2011, we added 50 mmboe of proved reserves and produced 68 mmboe.

The following table provides a summary of the changes in our proved oil and gas reserves after royalties during 2011.

| | Canada | | | | | | |
|---|---|---|---|---|---|---|---|
| | Oil Sands | | | | | | |
| (mmboe) | Syncrude Synthetic Oil | In Situ Synthetic Oil1 | Gas | United Kingdom | United States | Other2 | Total |
| December 31, 2010 | 296 | 291 | 46 | 204 | 36 | 45 | 918 |
| Discoveries | — | — | 4 | — | — | — | 4 |
| Extensions | 7 | 79 | 15 | 2 | — | — | 103 |
| Revisions – Technical | — | (59) | 1 | 24 | — | — | (34) |
| Revisions – Economic | (14) | (11) | (3) | 6 | — | (1) | (23) |
| Production | (7) | (5) | (8) | (33) | (7) | (8) | (68) |
| December 31, 2011 | 282 | 295 | 55 | 203 | 29 | 36 | 900 |

1 Represents reserves at Long Lake and Kinosis K1A.
2 Represents reserves in Yemen, Nigeria and Colombia.

During the year, proved reserves decreased by 18 mmboe as our net additions of 50 mmboe were less than production.

Discoveries of 4 mmboe at Horn River were due to the recognition of shale gas reserves in an additional shale gas zone.

Extensions of 103 mmboe were primarily due to recognizing Kinosis K1A reserves that are now being dedicated to the Long Lake upgrader and recognition of shale gas reserves for an 18-well Horn River pad that we expect to drill. The extensions of 79 mmboe at Kinosis K1A are included in our proved synthetic oil reserves as we are developing the area to feed the Long Lake upgrader.

Technical revisions resulted in a 34 million boe net reduction, which primarily relate to changes in our Long Lake expectations. These were partially offset by positive production performance at Buzzard, Telford and Ettrick in the UK North Sea, and at our Horn River shale gas development. The 59 million boe reduction of Long Lake synthetic oil reserves was the result of our re-assessment of the resource on the Long Lake lease which reflects a net reduction in the recoverable oil in some areas. It also reflects a downgrade of proved reserves that will be deferred by a change in our development plans to dedicate Kinosis K1A to the Long Lake project. The Kinosis K1A reserves have priority since they can be brought on stream faster.

Economic factors resulted in a negative revision of 23 mmboe, primarily at our oil sands properties, due to changes in average oil and gas prices and costs between 2010 and 2011. Higher synthetic oil prices resulted in our royalty obligation increasing by 25 million boe, as it takes more barrels to satisfy our obligations at higher prices. Our other properties had positive and negative economic revisions primarily due rising operating costs and increases in oil pricing and reductions in gas pricing.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

Proved Developed and Undeveloped Reserves

The following tables provide proved undeveloped reserves (PUDs) at December 31, 2011 and the changes during 2011:

| | Canada | | | | | | |
|---|---|---|---|---|---|---|---|
| | Oil Sands | | | | | | |
| (mmboe) | Syncrude Synthetic Oil | In Situ Synthetic Oil2 | Gas | United Kingdom | United States | Other1 | Total |
| December 31, 2010 | 114 | 244 | 7 | 64 | 9 | 34 | 472 |
| Discoveries | — | — | 3 | — | — | — | 3 |
| Extensions | 7 | 79 | 14 | 2 | — | — | 102 |
| Revisions – Technical | 1 | (45) | (1) | 9 | — | (1) | (37) |
| Revisions – Economic | (6) | (9) | (1) | 1 | — | (1) | (16) |
| Conversions | — | (8) | (6) | (27) | (1) | (16) | (58) |
| December 31, 2011 | 116 | 261 | 16 | 49 | 8 | 16 | 466 |
| PUD %3 | 41% | 89% | 29% | 24% | 28% | 44% | 52% |

1 Represents reserves in Yemen, Nigeria and Colombia.
2 Represents reserves at Long Lake and Kinosis K1A.
3 Determined as a percentage of total proved reserves for that area.

In 2011, our PUDs decreased by 6 mmboe as our extensions were largely offset by revisions and conversions to proved. Discoveries are from the recognition of a lower shale gas zone in Horn River. Extensions of 102 mmboe relate to the addition of Kinosis K1A area to the Long Lake upgrader project, an 18-well Horn River pad we expect to drill, West Rochelle in the UK and the addition of another year of Syncrude production which will come from an undeveloped mine. The negative economic revisions reflect the impact of higher price-sensitive royalties from our oil sands properties at Long Lake and Syncrude as it takes more barrels to satisfy our increased obligations at higher prices. We converted 58 mmboe of PUDs to proved developed, primarily at Buzzard and Telford in the UK North Sea and at Usan in Nigeria. At Usan, we are in the process of commissioning the production facilities and have converted about 50% of our prior year's PUDs which relate to the wells that have been drilled.

Approximately half of our proved reserves are undeveloped at December 31, 2011. More than 75% of these PUDs are located on our Canadian oil sand properties at Long Lake and Syncrude, which will be developed as we need bitumen feedstock to supply the upgraders during their expected lives. The in situ synthetic oil PUDs relate to reserves needed to supply the Long Lake upgrader over its expected life. They are expected to be converted to proved developed reserves over the next 28 years as we drill additional SAGD wells at Long Lake and K1A to offset declines from the initial wells. These wells were part of the initial field development plan and included in the project investment decision. The Syncrude synthetic oil PUDs relate to Syncrude's Aurora South mine. The Aurora South mine is included in the Syncrude development plan and was contemplated in the project investment decision relating to the Stage 3 expansion completed in 2005. We do not consider this mine to be developed as the extraction equipment required to access the reserves has not yet been moved to the mine site. We are proceeding with planning for the development of the mine and other mining leases and expect to commence construction in five to seven years. The

Aurora South mine PUDs of 116 mmboe are expected to be converted to proved developed reserves in eight to ten years.

In Canada, we have 16 mmboe of PUDs that relate primarily to planned development of one 18-well pad at our Horn River shale gas project in northeast British Columbia, which is expected to be completed over the next year.

In the UK North Sea, we have 49 mmboe of PUDs that relate primarily to development projects underway at Golden Eagle and Rochelle, and ongoing development of the Buzzard, Ettrick and Blackbird fields. All of these PUDs are expected to be converted within the next five years.

In our other international operations, 16 mmboe of PUDs relate primarily to Usan, offshore West Africa. They will be converted over the next three years as the subsea facilities are completed and additional wells are drilled and tied into the production facilities currently being commissioned.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

In 2011, we spent $1.3 billion on developing PUDs to proved developed reserves.

During the year, we converted 58 mmboe or about 12% of our PUDs that existed at the end of last year. The conversion rate in 2011 is low because about 80% of the PUDs relate to our oil sand projects at Long Lake where conversions take place over 28 years as the wells are needed to keep the Long Lake upgrader at capacity, and Syncrude where conversion will occur when the long cycle—time Aurora South mine is completed. Excluding these oil sand projects, we converted 45% of our 2010 PUDs to developed in 2011 and 83% of our PUDs over the last three years. We anticipate that our PUD conversion rate will vary considerably from year to year due to the stage and nature of projects associated with our oil and gas assets. The low conversion rate in 2011 is not necessarily indicative of future PUD conversion rates.

Excluding Long Lake and Syncrude, we expect to convert all of our PUDs to developed in the next four years. We have reviewed our PUDs and determined there are no material amounts in individual fields which have remained undeveloped for five years or more after they were initially recognized as proved reserves. We expect our ongoing exploration and development activities to continue to add new PUDs.

Following is a summary of our developed and undeveloped proved oil and gas reserves by country and product at December 31, 2011:

| | Synthetic Oil (mmbbls) | Oil (mmbbls) | Gas (bcf) |
|---|---|---|---|
| Canada | 200 | — | 227 |
| United Kingdom | — | 149 | 31 |
| United States | — | 10 | 70 |
| Other Countries | — | 20 | — |
| Developed | 200 | 179 | 328 |
| Canada | 377 | — | 99 |
| United Kingdom | — | 44 | 34 |
| United States | — | 4 | 21 |
| Other Countries | — | 16 | — |
| Undeveloped | 377 | 64 | 154 |
| | | | |
| Total proved | 577 | 243 | 482 |

Probable Reserves

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Therefore, probable reserves have a higher degree of uncertainty than proved reserves.

At December 31, 2011, we had 1,122 mmboe of probable reserves. During the year, our probable reserves increased by 127 mmboe. This is due to additions of 268 mmboe, which includes our Appomattox discovery, recognition of our Hangingstone bitumen property, extensions at the Horn River shale gas properties, and 78 mmboe from reclassifying synthetic oil reserves at Kinosis to bitumen reserves. This was partially offset by reductions of 93 mmboe due to negative economic factors and conversion of 126 mmboe to proved reserves.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

The following provides a summary of the changes in our probable oil and gas reserves during 2011:

| | | Canada | | | | | | |
|---|---|---|---|---|---|---|---|---|
| (mmboe) | Syncrude Synthetic Oil | Oil Sands In Situ Synthetic Oil | In Situ Bitumen[2] | Gas | United Kingdom | United States | Other[1] | Total |
| December 31, 2010 | 43 | 762 | — | 25 | 118 | 17 | 30 | 995 |
| Discoveries | — | — | 41 | 29 | 3 | 54 | — | 127 |
| Extensions | 7 | — | — | 95 | — | 1 | — | 103 |
| Revisions – Technical | — | 21 | — | 12 | 10 | (1) | (4) | 38 |
| Revisions – Economic | (1) | (91) | — | (2) | — | — | 1 | (93) |
| Reclassification to Bitumen[3] | — | (421) | 499 | — | — | — | — | 78 |
| Conversions[4] | (8) | (79) | — | (13) | (24) | (2) | — | (126) |
| December 31, 2011 | 41 | 192 | 540 | 146 | 107 | 69 | 27 | 1,122 |

1 Represents Yemen, Nigeria and Colombia.
2 Includes reserves for which there are no definitive plans for upgrading at this time.
3 Economic Revisions.
4 Technical Revisions.

Discoveries of 127 mmboe include recognition of probable reserves for successes in the south fault block on our Appomattox discovery in the US Gulf of Mexico, our Hangingstone non-operated oil sands property where we are advancing plans to construct a 174-well SAGD development, the Solitaire property in the UK North Sea and recognizing shale gas reserves in a lower shale gas zone in all Horn River wells.

Extensions of 103 mmboe primarily relate to additional drilling at Horn River, which is expected over the next five years.

Technical revisions resulted in a 38 mmboe increase primarily related to Long Lake, Kinosis and Horn River. Increases at Long Lake reflect the re-assessment of the resource and the reclassification of some proved reserves to probable reserves. Increases at Kinosis are a result of the re-evaluation of bitumen in place and recovery factors. Horn River reflects positive production performance supporting increased expected recoveries. Reductions are largely due to lower performance on our Canadian natural gas and CBM properties.

Economic revisions relate to changes in timing of our development plans at Long Lake and limiting the reserves to a 50-year production period and net royalty increases due to changes in price and operating costs.

Synthetic oil probable reserves reflect the reclassification of synthetic oil to bitumen as a result of our expectations regarding future plans for Kinosis. Currently we do not have sufficient certainty as to when we will build upgrading facilities at Kinosis and, therefore, are required to classify the reserves as bitumen.

Conversions reflect probable reserves that were converted to proved reserves as a result of increased expectations of producing the reserves based on advancement of development plans, production performance and drilling results. The largest change reflects the acceleration of the Kinosis K1A area development.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

Probable Developed and Undeveloped Reserves

Following is a summary of our developed and undeveloped probable oil and gas reserves by country and product at December 31, 2011:

| | Synthetic Oil (mmbbls) | Bitumen (mmbbls) | Oil (mmbbls) | Gas (bcf) |
|---|---|---|---|---|
| Canada | 7 | — | — | 86 |
| United Kingdom | — | — | 69 | 20 |
| United States | — | — | 5 | 42 |
| Other Countries | — | — | 6 | — |
| Developed | 7 | — | 80 | 148 |
| Canada | 226 | 540 | — | 782 |
| United Kingdom | — | — | 31 | 21 |
| United States | — | — | 50 | 45 |
| Other Countries | — | — | 21 | — |
| Undeveloped | 226 | 540 | 102 | 848 |
| | | | | |
| Total Probable | 233 | 540 | 182 | 996 |

Developed probable reserves typically reflect increased recovery factors and recompletions of other zones on producing wells. Undeveloped probable reserves reflect reserves that have not yet been drilled or the production facilities completed. They can also represent the reserves associated with higher recovery in proved undeveloped areas.

The majority of our probable reserves are undeveloped and primarily reflects incremental synthetic oil reserves related to future drilling required to keep the Long Lake upgrader full for 50 years, expected SAGD development of the bitumen resource at Kinosis, and extension of the plant life and expected higher future yields at Syncrude. These probable reserves will typically be developed in conjunction with proved reserves, but can take longer periods to develop. The remaining probable undeveloped reserves relate to ongoing pad development of Horn River, Appomattox in the Gulf of Mexico and discoveries offshore West Africa. We expect these remaining probable undeveloped reserves will be developed over the next seven years.

Our oil sands projects are large scale developments with significantly longer production lives than conventional oil and gas projects. The proved and probable reserves associated with these projects are developed over a period of decades within the limits of facility capacity.

Net Sales by Product from Oil and Gas Operations [1]

| (Cdn$ millions) | 2011 | 2010 | 2009[2] |
|---|---|---|---|
| Conventional Crude Oil and Natural Gas Liquids (NGLs) | 4,344 | 4,124 | 3,605 |
| Synthetic Crude Oil | 1,449 | 1,062 | 480 |
| Natural Gas | 327 | 410 | 316 |
| Total | 6,120 | 5,596 | 4,401 |

1 Includes results of discontinued operations (see Note 23 of our Consolidated Financial Statements).

2 Financial amounts for 2009 and earlier were prepared under previous Canadian Generally Accepted Accounting Principles and have not been restated for IFRS. Amounts for 2010 and 2011 were prepared under IFRS.

Crude oil (including synthetic crude oil) and NGLs represent approximately 93% of our oil and gas net sales, while natural gas represents the remaining 7%.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

Sales Prices and Production Costs

| | Average Sales Price1 | | | Average Production Cost1 | | |
|---|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | 2011 | 2010 | 20092 |
| Crude Oil and NGLs (Cdn$/bbl) | | | | | | |
| Oil Sands — Syncrude | 101.73 | 81.23 | 70.96 | 40.94 | 37.18 | 39.09 |
| Oil Sands — In Situ | 98.33 | 77.07 | — | 90.22 | 105.25 | — |
| Canada — Other | — | 61.39 | 53.04 | — | 20.97 | 20.82 |
| United Kingdom | 106.76 | 79.02 | 67.70 | 10.64 | 8.28 | 6.87 |
| United States | 99.65 | 76.73 | 65.01 | 13.22 | 10.76 | 14.10 |
| Yemen | 108.11 | 81.86 | 68.49 | 23.65 | 18.69 | 18.34 |
| Other Countries | 102.71 | 76.83 | 59.05 | 9.76 | 7.52 | 6.53 |
| Natural Gas (Cdn$/mcf) | | | | | | |
| Canada | 3.44 | 3.94 | 3.78 | 1.78 | 1.93 | 1.92 |
| United Kingdom | 7.42 | 5.28 | 3.95 | 1.77 | 1.38 | 1.15 |
| United States | 4.21 | 4.97 | 4.67 | 2.20 | 1.79 | 2.35 |
| Corporate Average (Cdn$/boe) | 91.46 | 70.11 | 60.02 | 21.30 | 17.40 | 13.33 |

1 Sales prices and unit production costs are calculated using our working interest production after royalties.
2 Financial amounts for 2009 and earlier were prepared under previous Canadian Generally Accepted Accounting Principles and have not been restated for IFRS. Amounts for 2010 and 2011 were prepared under IFRS.

Oil and Gas Acreage

| | Developed | | Undeveloped1 | | Total | |
|---|---|---|---|---|---|---|
| (thousands of acres) | Gross | Net | Gross | Net | Gross | Net |
| Oil Sands — In Situ | 14 | 9 | 656 | 279 | 670 | 288 |
| Oil Sands — Syncrude | 117 | 8 | 131 | 10 | 248 | 18 |
| Canada — Other | 605 | 458 | 1,071 | 717 | 1,676 | 1,175 |
| United Kingdom | 74 | 39 | 1,657 | 1,003 | 1,731 | 1,042 |
| United States | 162 | 89 | 1,206 | 564 | 1,368 | 653 |
| Yemen2 | 4 | 4 | 511 | 511 | 515 | 515 |
| Colombia3 | 2 | — | 1,617 | 1,531 | 1,619 | 1,531 |
| Nigeria2, 4 | 3 | 1 | 675 | 130 | 678 | 131 |
| Poland4 | — | — | 2,258 | 903 | 2,258 | 903 |
| Norway | — | — | 188 | 90 | 188 | 90 |
| Total5 | 981 | 608 | 9,970 | 5,738 | 10,951 | 6,346 |

1 Undeveloped acreage is considered to be those acres on which wells have not been drilled or completed to a point that would permit production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves.

2 The acreage is covered by production-sharing contracts.
3 The acreage is covered by an association contract.
4 The acreage is covered by joint venture agreements.
5 Approximately 26% of our net oil and gas acreage is scheduled to expire within three years if production is not established or we take no other action to extend the terms. We plan to continue the terms of many of these licences.

Producing Oil and Gas Wells

| | Oil | | Gas | | Total | |
|---|---|---|---|---|---|---|
| (number of wells) | Gross1 | Net2 | Gross1 | Net2 | Gross1 | Net2 |
| Canada | 125 | 76 | 2,772 | 2,502 | 2,897 | 2,578 |
| United Kingdom | 63 | 31 | — | — | 63 | 31 |
| United States | 78 | 43 | 65 | 42 | 143 | 85 |
| Yemen | 56 | 56 | — | — | 56 | 56 |
| Colombia | 111 | 11 | — | — | 111 | 11 |
| Total | 433 | 217 | 2,837 | 2,544 | 3,270 | 2,761 |

1 Gross wells are the total number of wells in which we own an interest.
2 Net wells are the sum of fractional interests owned in gross wells.

Drilling Activity

| | 2011 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Net Exploratory | | | Net Development | | | |
| (number of wells) | Productive | Dry Holes | Total | Productive | Dry Holes | Total | Total |
| Canada | 13.0 | — | 13.0 | 28.5 | — | 28.5 | 41.5 |
| United Kingdom | — | 3.9 | 3.9 | 1.7 | 0.9 | 2.6 | 6.5 |
| United States | — | — | — | — | — | — | — |
| Other Countries | — | 0.5 | 0.5 | 5.6 | — | 5.6 | 6.1 |
| Total | 13.0 | 4.4 | 17.4 | 35.8 | 0.9 | 36.7 | 54.1 |

| | 2010 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Net Exploratory | | | Net Development | | | |
| (number of wells) | Productive | Dry Holes | Total | Productive | Dry Holes | Total | Total |
| Canada | 9.0 | — | 9.0 | 21.5 | — | 21.5 | 30.5 |
| United Kingdom | 2.0 | 1.3 | 3.3 | 5.3 | 0.4 | 5.7 | 9.0 |
| United States | 0.5 | — | 0.5 | 0.8 | — | 0.8 | 1.3 |
| Other Countries | — | 0.7 | 0.7 | 12.6 | 0.5 | 13.1 | 13.8 |
| Total | 11.5 | 2.0 | 13.5 | 40.2 | 0.9 | 41.1 | 54.6 |

| | 2009 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Net Exploratory | | | Net Development | | | |
| (number of wells) | Productive | Dry Holes | Total | Productive | Dry Holes | Total | Total |
| Canada | 8.1 | — | 8.1 | 56.8 | — | 56.8 | 64.9 |
| United Kingdom | 3.1 | 1.3 | 4.4 | 5.7 | 0.8 | 6.5 | 10.9 |
| United States | 0.7 | 0.2 | 0.9 | 1.0 | — | 1.0 | 1.9 |
| Other Countries | 0.2 | — | 0.2 | 14.0 | — | 14.0 | 14.2 |
| Total | 12.1 | 1.5 | 13.6 | 77.5 | 0.8 | 78.3 | 91.9 |

Wells in Progress

At December 31, 2011, we were drilling two wells in the United Kingdom (1.2 net), one well in Canada (1.0 net) and two wells in the United States (0.7 net), one well in Colombia (1.0 net), two wells in Nigeria (0.4 net) and one well in Poland (0.4 net).

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

SUPPLEMENTARY DATA (UNAUDITED)

Oil and Gas Producing Activities (Unaudited)

The following oil and gas information is provided in accordance with the Financial Accounting Standards Board (FASB) Topic 932

Extractive Activities—Oil and Gas.

(A) RESERVE QUANTITY INFORMATION

The net proved reserves represent management's estimate of remaining proved oil and gas reserves after royalties. Every year, reserve estimates for each property are internally prepared. Our estimates of proved oil and gas reserves are determined through analysis of geological and engineering data, and demonstrate reasonable certainty that they are recoverable from known reservoirs under existing economic and operating conditions based on the 12-month average prices for 2010 and 2011, and year-end prices for prior years. See Basis of Reserves Estimates on pages 21 to 22 for a description of our oil and gas reserves estimation process.

| | Total—By Product | | | | | Canada | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Total (mmboe) | Synthetic Oil (mmbbls) | Bitumen (mmbbls) | Oil (mmbbls) | Gas (bcf) | Syncrude Synthetic Oil1 (mmbbls) | Oil Sands In Situ Synthetic Oil (mmbbls) | In Situ Bitumen (mmbbls) | Oil (mmbbls) | Gas (bcf) |
| Proved Reserves after Royalties | | | | | | | | | | |
| December 31, 2008 | 926 | 295 | 282 | 262 | 519 | 295 | — | 282 | 22 | 350 |
| Extensions and Discoveries | 63 | 7 | 23 | 28 | 33 | 7 | — | 23 | 1 | 16 |
| Revisions — Technical | 9 | — | (4) | 10 | 16 | — | — | (4) | (1) | 12 |
| Revisions — Economic3 | (2) | (7) | (9) | 27 | (81) | (7) | — | (9) | 13 | (87) |
| Acquisitions | 85 | — | 85 | — | — | — | — | 85 | — | — |
| Divestments | — | — | — | — | — | — | — | — | — | — |
| Production | (78) | (7) | (3) | (55) | (76) | (7) | — | (3) | (4) | (47) |
| | 1,003 | 288 | 374 | 272 | 411 | 288 | — | 374 | 31 | 244 |
| SEC RuleTransition2 | (83) | 291 | (374) | — | — | — | 291 | (374) | — | — |
| December 31, 2009 | 920 | 579 | — | 272 | 411 | 288 | 291 | — | 31 | 244 |
| Extensions and Discoveries | 66 | 10 | — | 36 | 121 | 7 | 3 | — | — | 90 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Revisions — Technical | 27 | (3) | — | 27 | 21 | — | (3) | — | — | (16) |
| Revisions — Economic3 | 13 | 12 | — | 1 | 1 | 8 | 4 | — | — | 7 |
| Acquisitions | 1 | — | — | 1 | 3 | — | — | — | — | — |
| Divestments | (30) | — | — | (29) | (8) | — | — | — | (29) | (8) |
| Production | (79) | (11) | — | (53) | (90) | (7) | (4) | — | (2) | (42) |
| December 31, 2010 | 918 | 587 | — | 255 | 459 | 296 | 291 | — | — | 275 |
| Discoveries | 4 | — | — | — | 26 | — | — | — | — | 26 |
| Extensions | 103 | 86 | — | 1 | 98 | 7 | 79 | — | — | 90 |
| Revisions — Technical | (34) | (59) | — | 24 | 8 | — | (59) | — | — | 3 |
| Revisions — Economic3 | (23) | (25) | — | 6 | (27) | (14) | (11) | — | — | (26) |
| Acquisitions | — | — | — | — | — | — | — | — | — | — |
| Divestments | — | — | — | — | — | — | — | — | — | — |
| Production | (68) | (12) | — | (43) | (82) | (7) | (5) | — | — | (43) |
| December 31, 2011 | 900 | 577 | — | 243 | 482 | 282 | 295 | — | — | 325 |
| Proved Undeveloped | | | | | | | | | | |
| December 31, 2010 | 472 | 358 | — | 94 | 122 | 114 | 244 | — | — | 44 |
| December 31, 2011 | 466 | 377 | — | 64 | 154 | 116 | 261 | — | — | 99 |
| Proved Developed 6 | | | | | | | | | | |
| December 31, 2010 | 446 | 229 | — | 161 | 337 | 182 | 47 | — | — | 231 |
| December 31, 2011 | 434 | 200 | — | 179 | 328 | 166 | 34 | — | — | 226 |

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

| | United Kingdom | | United States | | Other Countries4,5 |
|---|---|---|---|---|---|
| | Oil (mmbbls) | Gas (bcf) | Oil (mmbbls) | Gas (bcf) | Oil (mmbbls) |
| Proved Reserves after Royalties | | | | | |
| December 31, 2008 | 172 | 18 | 17 | 151 | 51 |
| Extensions and Discoveries | 19 | 6 | 1 | 11 | 7 |
| Revisions — Technical | 5 | 2 | 1 | 2 | 5 |
| Revisions — Economic3 | 9 | — | 3 | 6 | 2 |
| Acquisitions | — | — | — | — | — |
| Divestments | — | — | — | — | — |
| Production | (36) | (9) | (3) | (20) | (12) |
| | 169 | 17 | 19 | 150 | 53 |
| SEC Rule Transition2 | — | — | — | — | — |
| December 31, 2009 | 169 | 17 | 19 | 150 | 53 |
| Extensions and Discoveries | 35 | 29 | — | 2 | 1 |
| Revisions — Technical | 25 | 32 | 1 | 5 | 1 |
| Revisions —Economic3 | 1 | — | — | (6) | — |
| Acquisitions | 1 | 3 | — | — | — |
| Divestments | — | — | — | — | — |
| Production | (38) | (14) | (3) | (34) | (10) |
| December 31, 2010 | 193 | 67 | 17 | 117 | 45 |
| Discoveries | — | — | — | — | — |
| Extensions | 1 | 7 | — | 1 | — |
| Revisions — Technical | 24 | 3 | — | 2 | — |
| Revisions — Economic3 | 7 | (1) | — | — | (1) |
| Acquisitions | — | — | — | — | — |
| Divestments | — | — | — | — | — |
| Production | (32) | (10) | (3) | (29) | (8) |
| December 31, 2011 | 193 | 66 | 14 | 91 | 36 |
| Proved Undeveloped | | | | | |
| December 31, 2010 | 55 | 55 | 5 | 23 | 34 |
| December 31, 2011 | 44 | 34 | 4 | 21 | 16 |
| Proved Developed6 | | | | | |
| December 31, 2010 | 138 | 12 | 12 | 94 | 11 |
| December 31, 2011 | 149 | 32 | 10 | 70 | 20 |

1 As of December 31, 2008, our Syncrude oil sands activities were considered a mining activity rather than an oil and gas activity.

2 As of December 31, 2009, our in situ oil sands reserves are presented as synthetic oil barrels rather than bitumen barrels.

3 Prices underlying our economic assumptions used for reserve estimation in 2009 and 2010 are based on the average first-day-of-the-month prices during the year, rather than the year-end prices used in 2008.

4

Under the terms of the Masila and the Block 51 production sharing contracts, production was divided into cost recovery oil and profit oil. The Government's share of profit oil represents its royalty interest and an amount for income taxes payable in Yemen. Yemen's net proved reserves were determined using the economic interest method and include our share of future cost recovery and profit oil after the Government's royalty interest, but before reserves relating to income taxes payable. Under this method, reported reserves increased as oil prices decreased (and vice versa) as the barrels necessary to achieve cost recovery change with prevailing oil prices. Production included volumes used for fuel.

5 Represents reserves in Yemen, Nigeria and Colombia.

6 Proved developed oil and gas reserves are expected to be recovered through existing wells with existing equipment and operating methods.

(B) CAPITALIZED COSTS

| (Cdn$ millions) | Proved Properties | Unproved Properties | Accumulated DD&A | Capitalized Costs |
|---|---|---|---|---|
| December 31, 2011 | | | | |
| United Kingdom | 5,967 | 1,136 | (3,707) | 3,396 |
| Canada | 2,451 | 476 | (1,230) | 1,697 |
| Oil Sands In Situ | 5,001 | 914 | (205) | 5,710 |
| Oil Sands Syncrude | 1,733 | — | (411) | 1,322 |
| United States | 4,066 | 263 | (3,069) | 1,260 |
| Other Countries | 2,483 | 83 | (648) | 1,918 |
| Total Capitalized Costs | 21,701 | 2,872 | (9,270) | 15,303 |
| December 31, 2010 | | | | |
| United Kingdom | 5,412 | 977 | (3,055) | 3,334 |
| Canada | 1,909 | 589 | (870) | 1,628 |
| Oil Sands In Situ | 4,868 | 888 | (91) | 5,665 |
| Oil Sands Syncrude | 1,519 | — | (359) | 1,160 |
| United States | 3,666 | 258 | (2,727) | 1,197 |
| Other Countries | 3,647 | 53 | (2,370) | 1,330 |
| Total Capitalized Costs | 21,021 | 2,765 | (9,472) | 14,314 |
| December 31, 2009[1] | | | | |
| United Kingdom | 4,995 | 1,120 | (2,664) | 3,451 |
| Canada | 3,383 | 573 | (2,424) | 1,532 |
| Oil Sands In Situ | 5,223 | 829 | (7) | 6,045 |
| Oil Sands Syncrude | 1,463 | — | (270) | 1,193 |
| United States | 3,665 | 235 | (2,529) | 1,371 |
| Other Countries | 3,340 | 52 | (2,421) | 971 |
| Total Capitalized Costs | 22,069 | 2,809 | (10,315) | 14,563 |

1 Prior to 2011, our financial statements were prepared in accordance with previous Canadian GAAP. In the first quarter of 2011, we adopted IFRS with an effective date as at January 1, 2010 and restated the 2010 financial results to be in accordance with IFRS. Further details regarding our transition to IFRS are included in Note 26 of the Consolidated Financial Statements. As such, amounts prior to 2010 are presented in accordance with previous Canadian GAAP and have not been restated.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

(C) COSTS INCURRED

| (Cdn$ millions) | Total Oil and Gas | United Kingdom | Canada Other | Oil Sands In Situ | Oil Sands Syncrude | United States | Other Countries |
|---|---|---|---|---|---|---|---|
| Year Ended | | | | | | | |
| December 31, 2011 | | | | | | | |
| Property Acquisition Costs | | | | | | | |
| Proved | — | — | — | — | — | — | — |
| Unproved | 17 | 12 | 3 | — | — | 2 | — |
| Exploration Costs | 902 | 87 | 391 | 114 | — | 154 | 156 |
| Development Costs | 2,123 | 644 | 135 | 299 | 222 | 229 | 594 |
| Total Costs Incurred | 3,042 | 743 | 529 | 413 | 222 | 385 | 750 |
| Year Ended | | | | | | | |
| December 31, 2010 | | | | | | | |
| Property Acquisition Costs | | | | | | | |
| Proved | 79 | 79 | — | — | — | — | — |
| Unproved | 552 | 176 | 315 | — | — | 61 | — |
| Exploration Costs | 540 | 35 | 222 | 60 | — | 120 | 103 |
| Development Costs | 1,758 | 658 | 66 | 175 | 142 | 152 | 565 |
| Total Costs Incurred | 2,929 | 948 | 603 | 235 | 142 | 333 | 668 |
| Year Ended | | | | | | | |
| December 31, 2009[1] | | | | | | | |
| Property Acquisitions Costs | | | | | | | |
| Proved | 755 | — | — | 755 | — | — | — |
| Unproved | 13 | — | 3 | — | — | 10 | — |
| Exploration Costs | 650 | 155 | 224 | 1 | — | 183 | 87 |
| Development Costs | 1,923 | 457 | 115 | 549 | 114 | 120 | 568 |
| Total Costs Incurred | 3,341 | 612 | 342 | 1,305 | 114 | 313 | 655 |

1 Prior to 2011, our financial statements were prepared in accordance with previous Canadian GAAP. In the first quarter of 2011, we adopted IFRS with an effective date as at January 1, 2010 and restated the 2010 financial results to be in accordance with IFRS. Further details regarding our transition to IFRS are included in Note 26 of the Consolidated Financial Statements. As such, amounts prior to 2010 are presented in accordance with previous Canadian GAAP and have not been restated.

(D) RESULTS OF OPERATIONS FOR PRODUCING ACTIVITIES

| (Cdn$ millions) | Total Oil and Gas | United Kingdom | Canada[1] | Oil Sands In Situ | Oil Sands Syncrude | United States | Other Countries |
|---|---|---|---|---|---|---|---|
| Year Ended December 31, 2011 | | | | | | | |
| Net Sales | 6,113 | 3,432 | 111 | 688 | 713 | 388 | 781 |
| Production Costs | 1,399 | 353 | 57 | 439 | 287 | 99 | 164 |
| Exploration Expense | 368 | 84 | 43 | 2 | — | 105 | 134 |
| Depreciation, Depletion, Amortization and Impairment | 1,859 | 631 | 417 | 384 | 60 | 291 | 76 |
| Other Expenses (Income) | 352 | (43) | 53 | 242 | 27 | 33 | 40 |
| | 2,135 | 2,407 | (459) | (379) | 339 | (140) | 367 |
| Income Tax Provision (Recovery) | 1,590 | 1,697 | (115) | (95) | 84 | (49) | 68 |
| Results of Operations | 545 | 710 | (344) | (284) | 255 | (91) | 299 |
| Year Ended December 31, 2010 | | | | | | | |
| Net Sales | 5,595 | 3,115 | 283 | 443 | 580 | 424 | 750 |
| Production Costs | 1,354 | 337 | 119 | 373 | 265 | 97 | 163 |
| Exploration Expense | 328 | 67 | 41 | 1 | — | 115 | 104 |
| Depreciation, Depletion, Amortization and Impairment | 1,589 | 783 | 205 | 94 | 53 | 334 | 120 |
| Other Expenses (Income) | (501) | 7 | (759) | 118 | 21 | 72 | 40 |
| | 2,825 | 1,921 | 677 | (143) | 241 | (194) | 323 |
| Income Tax Provision (Recovery) | 1,149 | 960 | 169 | (36) | 60 | (68) | 64 |
| Results of Operations | 1,676 | 961 | 508 | (107) | 181 | (126) | 259 |
| Year Ended December 31, 2009[2] | | | | | | | |
| Net Sales | 4,401 | 2,430 | 395 | — | 480 | 321 | 775 |
| Production Costs | 986 | 253 | 171 | — | 265 | 98 | 199 |
| Exploration Expense | 302 | 50 | 83 | 1 | — | 104 | 64 |
| Depreciation, Depletion, Amortization and Impairment | 1,667 | 875 | 296 | 5 | 63 | 312 | 116 |
| Other Expenses (Income) | 265 | 17 | 86 | 7 | 22 | 82 | 51 |
| | 1,181 | 1,235 | (241) | (13) | 130 | (275) | 345 |
| Income Tax Provision (Recovery) | 479 | 487 | (61) | (3) | 33 | (95) | 118 |
| Results of Operations | 702 | 748 | (180) | (10) | 97 | (180) | 227 |

1 Includes the results of discontinued operations.

2 Prior to 2011, our financial statements were prepared in accordance with previous Canadian GAAP. In the first quarter of 2011, we adopted IFRS with an effective date as at January 1, 2010 and restated the 2010 financial results

to be in accordance with IFRS. Further details regarding our transition to IFRS are included in Note 26 of the Consolidated Financial Statements. As such, amounts prior to 2010 are presented in accordance with previous Canadian GAAP and have not been restated

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

(E) STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS AND CHANGES THEREIN

The following disclosure is based on estimates of net proved reserves and the period during which they are expected to be produced. Future cash inflows are computed by applying average annual prices to our after royalty share of estimated annual future production from proved oil and gas reserves. As a result of amended FASB oil and gas disclosure rules, future cash inflows as of December 31, 2009 and thereafter were computed using the average first-day-of-the-month prices for the year held constant. Future cash inflows at December 31, 2008 were computed using the year-end prices held constant. Future development, production and abandonment costs to be incurred in producing and further developing the proved reserves are based on existing cost indicators. Future income taxes are computed by applying year-end statutory tax rates. These rates reflect allowable deductions and tax credits, and are applied to the estimated pre-tax future net cash flows.

Discounted future net cash flows are calculated using 10% mid-period discount factors. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proved to be the case in the past. Other assumptions could give rise to substantially different results.

We believe this information does not reflect the current economic value of our oil and gas producing properties or the present value of their estimated future cash flows as:

- no economic value is attributed to probable and possible reserves;
- use of a 10% discount rate is arbitrary; and
- prices change constantly from the prices used.

| | | Canada | | | | | |
|---|---|---|---|---|---|---|---|
| | | Oil Sands | | | | | |
| (Cdn$ millions) | Total | Syncrude Synthetic Oil | In Situ Synthetic Oil | Other | United Kingdom | United States | Other Countries |
| December 31, 2011 | | | | | | | |
| Future Cash Inflows | 87,256 | 29,058 | 30,189 | 1,141 | 21,199 | 1,838 | 3,831 |
| Future Production Costs | 37,688 | 14,312 | 17,076 | 808 | 4,364 | 378 | 750 |
| Future Development Costs | 7,688 | 1,433 | 3,853 | 201 | 1,485 | 196 | 520 |
| Future Dismantlement and Site Restoration Costs, Net | 2,281 | 175 | 187 | 194 | 1,108 | 508 | 109 |
| Future IncomeTax | 12,223 | 1,941 | 1,242 | — | 8,978 | — | 62 |
| Future Net Cash Flows | 27,376 | 11,197 | 7,831 | (62) | 5,264 | 756 | 2,390 |
| 10% Discount Factor | 15,984 | 7,855 | 6,037 | (60) | 1,353 | 160 | 639 |
| Standardized Measure | 11,392 | 3,342 | 1,794 | (2) | 3,911 | 596 | 1,751 |
| December 31, 2010 | | | | | | | |
| Future Cash Inflows | 69,323 | 23,998 | 23,293 | 1,049 | 15,594 | 1,831 | 3,558 |
| Future Production Costs | 33,631 | 14,002 | 13,200 | 706 | 4,437 | 449 | 837 |
| | 6,875 | 1,061 | 3,142 | 95 | 1,608 | 253 | 716 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Future Development Costs | | | | | | | |
| Future Dismantlement and Site Restoration Costs, Net | 2,226 | 182 | 147 | 242 | 1,094 | 432 | 129 |
| Future IncomeTax | 6,251 | 1,241 | 416 | — | 4,433 | — | 161 |
| Future Net Cash Flows | 20,340 | 7,512 | 6,388 | 6 | 4,022 | 697 | 1,715 |
| 10% Discount Factor | 11,875 | 5,579 | 4,665 | (65) | 985 | 126 | 585 |
| Standardized Measure | 8,465 | 1,933 | 1,723 | 71 | 3,037 | 571 | 1,130 |
| December 31, 2009 | | | | | | | |
| Future Cash Inflows | 59,427 | 21,290 | 20,294 | 2,597 | 10,366 | 1,708 | 3,172 |
| Future Production Costs | 33,180 | 14,480 | 12,306 | 1,702 | 3,160 | 688 | 844 |
| Future Development Costs | 5,384 | 1,170 | 2,563 | 41 | 433 | 107 | 1,070 |
| Future Dismantlement and Site Restoration Costs, Net | 1,660 | 166 | 189 | 246 | 541 | 391 | 127 |
| Future IncomeTax | 3,727 | 249 | 238 | 28 | 3,017 | — | 195 |
| Future Net Cash Flows | 15,476 | 5,225 | 4,998 | 580 | 3,215 | 522 | 936 |
| 10% Discount Factor | 9,183 | 4,217 | 3,633 | 24 | 725 | 95 | 489 |
| Standardized Measure | 6,293 | 1,008 | 1,365 | 556 | 2,490 | 427 | 447 |

CHANGES IN THE STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

| (Cdn$ millions) | 2011 | 2010 | 2009 |
|---|---|---|---|
| Beginning of Year | 8,465 | 6,293 | 4,423 |
| Sales and Transfers of Oil and Gas Produced, Net of Production Costs | (3,244) | (3,018) | (2,306) |
| Net Changes in Prices and Production Costs Related to Future Production | 5,554 | 3,364 | 561 |
| Extensions, Discoveries and Improved Recovery, Less Related Costs | 537 | 373 | 884 |
| Changes in Estimated Future Development and Dismantlement Costs | (939) | (580) | (306) |
| Previous Estimated Future Development and Dismantlement Costs Incurred During the Period | 1,300 | 782 | 1,091 |
| Revisions of Previous Quantity Estimates | 1,930 | 1,245 | 607 |
| Accretion of Discount | 1,183 | 901 | 655 |
| Purchase of Reserves in Place | (3) | 51 | 330 |
| Sales of Reserves in Place | (10) | (301) | (2) |
| Net Change in Income Taxes | (3,381) | (645) | (596) |
| | 11,392 | 8,465 | 5,341 |
| Inclusion of Syncrude as Oil and Gas Activity | — | — | 1,008 |
| Conversion of In Situ Bitumen to Synthetic Reserves | — | — | (56) |
| End of Year | 11,392 | 8,465 | 6,293 |

# APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

APPENDIX C—FORM 51-101F2
REPORT ON RESERVES DATA BY INTERNAL QUALIFIED RESERVES EVALUATOR

To the board of directors of Nexen Inc. (the Company):

1. The Company's staff and I have evaluated 100% of the Company'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 in accordance with National Instrument 51-101 (the Reserves Data).

2. The Reserves Data are the responsibility of the Company's management. My responsibility is to express an opinion on the Reserves Data based on my evaluation. The Company's staff and I carried out an evaluation in accordance with 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 the evaluation is planned and performed to obtain reasonable assurance as to whether the Reserves Data are free of material misstatement. An evaluation also includes assessing whether the Reserves Data are in accordance with principles and definitions 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:

| Location of Reserves (country or foreign geographic region) | Net Present Value of Future Net Revenue of Reserves Evaluated (before income taxes, 10% discount rate) (Cdn $millions) |
|---|---|
| United Kingdom | 14,675 |
| Canada | 8,186 |
| United States | 2,236 |
| Other | 2,629 |
| Total Company | 27,726 |

5. Among other things, with respect to matters regarding royalties, operating costs, development plans and costs, abandonment plans and costs, and income taxes (where applicable), I have placed reasonable reliance on the information and decisions of others in their areas of authority, responsibility and expertise within the Company.

6. I am not independent of the Company, within the meaning of the term "independent" under National Instrument 51-101 — Standards of Disclosure for Oil and Gas Activities.

7. In my opinion, the Reserves Data has, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.

8. I have no responsibility to update this opinion for events and circumstances occurring after their respective preparation dates.

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

10. I have signed this form in my capacity as an employee of Nexen Inc. and not in my personal capacity.

DATED as of this 15th day of February, 2012.

(signed) Ian R. McDonald
Ian R. McDonald, P. Eng.
Nexen Inc.
Internal Qualified Reserves Evaluator
Calgary, Alberta

# APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

APPENDIX D—FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON NI 51-101 OIL AND GAS DISCLOSURE

Management of Nexen Inc. (the Company) is responsible for the preparation and disclosure of information with respect to the Company'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 in accordance with National Instrument 51-101 (the Reserves Data).

The Company's reserves evaluation staff, including our Internal Qualified Reserves Evaluator who is an employee of the Company, have evaluated the Company's Reserves Data. The report of the Internal Qualified Reserves Evaluator (the IQRE) accompanies this report.

The Reserves Committee of the board of directors of the Company has

(a) reviewed the Company's procedures used by the IQRE and other internal qualified reserves evaluators to prepare the Reserves Data;
(b) met with the IQRE to determine whether any restrictions affected the ability of the IQRE to report without reservation; and
(c) reviewed the Reserves Data with management and the IQRE.

The Reserves Committee of the board of directors has reviewed the Company'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 the Reserves Data and other oil and gas information;
(b) the filing of a report on the Reserves Data by the IQRE; and
(c) the content and filing of this report.

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

DATED as of this 15th day of February, 2012.

(signed) Kevin J. Reinhart
Kevin J. Reinhart
Interim President and
Chief Executive Officer

(signed) Una M. Power
Una M. Power
Interim Chief Financial Officer

(signed) William B. Berry
William B. Berry
Director

(signed) Thomas C. O'Neill
Thomas C. O'Neill
Director

# APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

## II. Opinion Letters of the Independent Reserves Evaluators

The following is the text of the opinion letters issued by the Independent Reserves Evaluators to Nexen in respect of the reserves of Nexen.

### (1) Opinion Letter of D&M

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East Dallas, Texas 75244

January 26, 2012

This is a digital representation of a DeGolyer and MacNaughton report.

This file is intended to be a manifestation of certain data in the subject report and as such are subject to the same conditions thereof. The information and data contained in this file may by subject to misinterpretation; therefore, the signed and bound copy of this report should be considered the only authoritative source of such information.

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East Dallas, Texas 75244

Attention: Reserves Review Committee of the Board of Directors of Nexen Inc.

Re: DeGolyer and MacNaughton – Opinion for certain International and Canadian properties owned by Nexen Inc.

Ladies and Gentlemen:
Pursuant to your request, we have conducted independent evaluations of Nexen Inc.'s (Nexen) proved and probable oil, condensate, natural gas liquids (NGL), and natural gas reserves, as of December 31, 2011, for certain fields with interests owned by Nexen in the United Kingdom, Nigeria, and Canada (our Reports) as shown in Table 1. Nexen has represented that these properties account for 29 percent of its total company proved reserves and 24 percent of its total company proved-plus-probable reserves on an equivalent barrel basis as of December 31, 2011, and that its reserves estimates have been prepared in accordance with the principles and definitions presented in National Instrument 51-101 – Standards of Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (COGE Handbook). We have reviewed information provided to us by Nexen that it represents to be its estimates of the reserves, as of December 31, 2011, for the same properties as those which we evaluated.

Our estimate was prepared using standard geological and engineering methods generally recognized by the petroleum industry, and the reserves principles, definitions, and standards required by NI 51-101 and the COGE Handbook. Generally accepted methods for estimating reserves include volumetric calculations, material-balance techniques, production-decline curves, pressure-transient analysis, analogy with similar reservoirs, and reservoir simulation. The method or combination of methods used was based on our professional judgment and experience.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

Nexen Estimates

Nexen has represented that its estimated proved and proved-plus-probable reserves attributable to the evaluated properties are as follows, expressed in millions of barrels (bbl), billions of cubic feet, and millions of barrels of oil equivalent (boe):

| Nexen Reserves | Nexen's Estimate of Reserves as of December 31, 2011 Select International and Canadian Properties Evaluated by DeGolyer and MacNaughton | | |
|---|---|---|---|
| | Liquids | Natural Gas | Oil Equivalent |
| | (millions of bbl) | (billions of cubic feet) | (millions of boe) |
| Working Interest Reserves (before royalties) | | | |
| Proved | 229 | 384 | 293 |
| Proved plus Probable | 365 | 1,167 | 559 |

Note: Liquids include crude oil, condensate, and natural gas liquids. Gas is converted to oil equivalent using a factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

Reserves Opinion

DeGolyer and MacNaughton has used all data, assumptions, procedures, and methods that it considers necessary to prepare our Reports.

The reserves data relating to estimated proved and probable reserves contained in our Reports have, in all material respects, been prepared in accordance with the COGE Handbook and NI 51-101.

In comparing the detailed proved and proved-plus-probable reserves estimates prepared by us to those prepared by Nexen, we have found differences, both positive and negative. In our opinion, the proved and proved-plus-probable reserves for the reviewed properties as estimated by Nexen are, in aggregate, when compared to our estimates on the basis of equivalent barrels, reasonable because each was within 10 percent of our estimates.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Nexen. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of Nexen.

Submitted,
DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

CC: Mr. Sergio Merchan
Mgr – Subsurface Technical Assurance International Division
Mr. David Richardson P. Eng.
Canadian Oil and Gas Division Reserves Manager
Deloitte & Touche LLP, Attn: Brad Kopas

Lloyd W. Cade, P.E.
SEAL
Senior Vice President
DeGolyer and MacNaughton

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

TABLE 1
NEXEN FIELDS EVALUATED by DEGOLYER and MACNAUGHTON
as of DECEMBER 31, 2011

| PROPERTIES | FIELDS |
|---|---|
| United Kingdom | Blackbird |
| | Buzzard |
| | Ettrick |
| | Farragon |
| | Golden Eagle Area |
| | Peregrine |
| | Rochelle |
| | Scott |
| | Solitaire |
| | Telford |
| Nigeria | Owowo South B |
| | Usan (Block OML-138) |
| | Usan West |
| Canada | Dilly Creek |

(2) Opinion Letters of McDaniel

Opinion – Select Canadian In-Situ Oil Sands Properties

January 26, 2012

Nexen Inc.
801-7th Avenue S.W.
Calgary, AB
T2P 3P7

Attention: Reserves Review Committee of the Board of Directors of Nexen Inc.

Re:McDaniel & Associates Consultants Ltd. – Opinion for Select Canadian In-Situ Oil Sands Properties owned by Nexen Inc.

Ladies and Gentlemen:

Pursuant to your request, McDaniel & Associates Consultants Ltd. (McDaniel) has conducted an evaluation of Nexen Inc.'s (Nexen) proved and probable synthetic crude oil and bitumen reserves, as of December 31, 2011, for Nexen's Long Lake, Kinosis and Hangingstone properties as shown in Table 1. Nexen has represented that these properties account for 32 percent of its total company proved reserves and 53 percent of its total company proved plus probable reserves on an equivalent barrel basis as of December 31, 2011, and that its reserves estimates have been prepared in accordance with the principles and definitions presented in National Instrument 51-101 – Standards of Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (COGE Handbook). We have reviewed information provided to us by Nexen that it represents to be to be its estimates of the reserves, as of December 31, 2011, for the same properties as those which we evaluated.

Our estimate was prepared using standard geological and engineering methods generally recognized by the petroleum industry, and the reserves principles, definitions and standards required by NI 51-101 and the COGE Handbook. Generally accepted methods for estimating reserves include volumetric calculations, material balance techniques, production decline curves and pressure transient analysis, analogy with similar reservoirs, and reservoir simulation. The method or combination of methods used was based on our professional judgment and experience.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

Nexen Estimates

Nexen has represented that estimated proved and proved plus probable reserves attributable to the evaluated properties are as follows:

| Nexen Reserves | Nexen's estimate of Reserves as of December 31, 2011 Select Canadian In-Situ Oil Sands Properties Evaluated by McDaniel & Associates Synthetic Crude Oil (millions of bbl) | Bitumen (million of bbl) | Oil Equivalent (millions of boe) |
|---|---|---|---|
| Working Interest Reserves (before royalties) | | | |
| Proved | 319 | 0 | 319 |
| Proved plus Probable | 551 | 661 | 1,212 |

Reserves Opinion

McDaniel has used all data, assumptions, procedures and methods that it considers necessary to prepare our report.

The reserves data relating to estimated proved and probable reserves contained in our report have, in all material respects, been prepared in accordance with the COGE Handbook and NI 51-101.

In comparing the detailed proved and proved plus probable reserves estimates prepared by us to those prepared by Nexen, we have found differences, both positive and negative. In our opinion, the proved and proved plus probable reserves for the reviewed properties as estimated by Nexen are, in aggregate, when compared to our estimates on the basis of equivalent barrels, reasonable because each was within 10 percent of our estimates.

The analyses of these properties, as reported herein, were conducted within the context of an audit of a distinct group of properties in aggregate as part of the total corporate level reserves. Extraction and use of these analyses outside of this context may not be appropriate without supplementary due diligence.

McDaniel is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over 50 years. McDaniel does not have any financial interest, including stock ownership, in Nexen. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of Nexen.

If there are any questions, please contact the writer directly at (403) 218-1379.

Sincerely,
McDaniel & Associates Consultants Ltd.
P.A.Welch, P.Eng
President & Managing Director

CC: Mr. David Richardson, P. Eng., Canadian Oil and Gas, Division Reserves Manager
Mr. Brad Kopas, Deloitte & Touche LLP,

Table 1
Nexen Properties Evaluated by McDaniel & Associates
Select Canadian In-Situ Oil Sands Properties
December 31, 2011

| BUSINESS UNIT | FIELD NAME |
|---|---|
| 1 OIL SANDS | LONG LAKE |
| 2 OIL SANDS | KINOSIS |
| 3 OIL SANDS | HANGINGSTONE |

Opinion – Syncrude

January 26, 2012

Nexen Inc.
801 – 7th Avenue SW
Calgary, Alberta
T2P 3P7

Attention: Reserves Review Committee of the Board of Directors of Nexen Inc.

Re:McDaniel & Associates Consultants Ltd. – Opinion for the Syncrude property owned by Nexen Inc.

Ladies and Gentlemen:

Pursuant to your request, McDaniel & Associates Consultants Ltd. (McDaniel) has conducted an audit of Nexen Inc.'s (Nexen) proved and probable synthetic crude oil reserves in Syncrude Canada Ltd. (Syncrude), as of December 31, 2011. Nexen has represented that this property accounts for 32 percent of its total company proved reserves and 16 percent of its total company proved plus probable reserves for its Syncrude ownership on an equivalent barrel basis as of December 31, 2011, and that its reserve estimates have been prepared in accordance with the principles and definitions presented in National Instrument 51-101 – Standards of Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (COGE Handbook). We have reviewed information provided to us by Nexen that it represents to be its estimate of the reserves, as of December 31, 2011, for the Syncrude property.

We have performed our audit by reviewing the estimates, assumptions, supporting working papers and other data underlying the reserves estimate prepared by Nexen. We have audited to the standard geological and engineering methods generally recognized by the petroleum industry, and the reserves reserves principles, definitions and standards required by NI 51-101 and the COGE Handbook. Our assessment of the method or combination of methods used for reserves estimates was based on our professional judgment and experience.

Nexen Estimates

Nexen has represented that estimated proved and proved plus probable reserves attributable to the evaluated properties are as follows:

| Nexen Reserves | Nexen's estimate of Syncrude Reserves as of December 31, 2011 | |
|---|---|---|
| | Synthetic Crude oil (millions of bbl) | Oil Equivalent (millions of boe) |
| Working Interest Reserves (before royalties) | | |
| Proved | 324 | 324 |
| Proved plus Probable | 370 | 370 |

Reserves Opinion

McDaniel has used all data, assumptions, procedures and methods that it considers necessary to prepare this audit opinion.

In our opinion, Nexen's estimates of proved and probable reserves for the reviewed property have, in all material respects, been determined and are in accordance with the COGE Handbook and NI 51-101.

In our opinion, the proved and proved plus probable reserves for the reviewed property as estimated by Nexen are, in aggregate, reasonable because if we were to perform our own detailed evaluation of the property we would expect the resulting estimates to be within 10 percent of Nexen's estimates.

The analysis of this property, as reported herein, was conducted within the context of an audit in aggregate as part of the total corporate level reserves. Extraction and use of this analysis outside of this context may not be appropriate without supplementary due diligence.

McDaniel is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over 50 years. McDaniel does not have any financial interest, including stock ownership, in Nexen. Our fees were not contingent on the results of our audit. This letter report has been prepared at the request of Nexen.

If there are any questions, please contact the writer directly at (403) 218-1379.

Sincerely,
McDaniel & Associates Consultants Ltd.
P.A.Welch, P.Eng
President & Managing Director

CC: Mr. B Frasson, P. Eng., MBA
Director – Syncrude Investment

Mr. Brad Kopas
Deloitte & Touche LLP

(3) Opinion Letter of Ryder Scott

January 26, 2012

Nexen Inc.
801-7th Avenue S.W.
Calgary, AB
T2P 3P7

Attention: Reserves Review Committee of the Board of Directors of Nexen Inc.

Re: Ryder Scott Company L.P. – Opinion for certain properties located in the United States Gulf of Mexico with interests owned by Nexen Inc.

Ladies and Gentlemen:

Pursuant to your request, Ryder Scott Company L.P. ("Ryder Scott") has conducted an independent evaluation of Nexen Inc.'s (Nexen) proved and probable oil, natural gas liquids (NGL), and gas reserves for certain properties owned by Nexen in the United States Gulf of Mexico Shelf and Deep Water. The properties evaluated are listed in Table 1. Nexen has represented that these properties account for 3 percent of its total company proved reserves and 5 percent of its total company proved plus probable reserves on an equivalent barrel basis as of December 31, 2011, and that its reserves estimates have been prepared in accordance with the principles and definitions presented in National Instrument 51-101 – Standards of Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (COGE Handbook). We have reviewed information provided to us by Nexen that it represents to be its estimates of the reserves, as of December 31, 2011, for the same properties as those which we evaluated.

Our estimate was prepared using standard geological and engineering methods generally recognized by the petroleum industry, and the reserves principles, definitions and standards required by NI 51-101 and the COGE Handbook. Generally accepted methods for estimating reserves include volumetric calculations, material balance techniques, production decline curves and pressure transient analysis, analogy with similar reservoirs, and reservoir simulation. The method or combination of methods used was based on our professional judgment and experience.

APPENDIX IV 2011 AIF OF NEXEN AND OPINION LETTERS OF THE INDEPENDENT RESERVES EVALUATORS

Nexen Estimates

Nexen has represented that estimated proved and proved plus probable reserves attributable to the evaluated properties are as follows:
Nexen's Estimate of Reserves as of December 31, 2011
Selected Gulf of Mexico Properties Evaluated by Ryder Scott Company L.P.

| Nexen Reserves | Liquids (millions of bbl) | Natural Gas (billions of cubic feet) | Oil Equivalent (millions of boe) |
|---|---|---|---|
| Working Interest (before royalty) | | | |
| Total Proved | 15 | 102 | 32 |
| Total Proved plus Probable | 79 | 201 | 113 |

Note: Liquids include crude oil, condensate and natural gas liquids Natural Gas is converted to oil equivalent using a factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

Reserves Opinion

The reserves data relating to estimated proved and probable reserves contained in our report have, in all material respects, been prepared in accordance with the COGE Handbook and NI 51-101.

In comparing the detailed proved and proved plus probable reserves estimates prepared by us to those prepared by Nexen, we have found differences, both positive and negative. In our opinion, the proved and proved plus probable reserves for the reviewed properties as estimated by Nexen are, in aggregate, when compared to our estimates on the basis of equivalent barrels, reasonable because each was within 10 percent of our estimates.

Ryder Scott has used all data, assumptions, procedures and methods that it considers necessary to prepare this report. Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy years. Ryder Scott does not have any financial interest, including stock ownership, in Nexen. Our fees were not contingent on the results of our evaluation.

The professional qualifications for Mr. Richard J. Savoie, the technical person primarily responsible for estimating and auditing the reserves information discussed in this letter report, are included as an attachment to this letter.

This letter report has been prepared at the request of Nexen.

Sincerely,
RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580
Richard J. Savoie, P. E.
TBPE License No. 40538
Senior Vice President

RJS/pl

cc:Mr. Steve Aeschbach,
Reserves Manager,
Nexen Petroleum U.S.A. Inc.

Mr. Brad Kopas,
Deloitte & Touche LLP

Table 1
Nexen Properties Evaluated by Ryder Scott Company L.P.
United States: Gulf of Mexico properties
As of December 31, 2011

| | |
|---|---|
| Shelf Properties | |
| Cote de Mer | South Marsh Island 257 |
| Eugene Island 255-57-58 | Vermilion 76 |
| Eugene Island 259 | West Cameron 170 |
| Eugene Island 295 | |
| High Island 582 | |
| | |
| Deep Water Properties | |
| Aspen | Knotty Head |
| Dawson | Longhorn |
| Garden Banks 205 | Gunnison |
| Mississippi Canyon 72 | Tobago |
| Green Canyon 6 | Wrigley |
| Green Canyon 137 | Appomattox |

# APPENDIX V QUALIFICATIONS AND EXPERIENCE OF THE IQRE AND THE INDEPENDENT RESERVES EVALUATORS

The following sets out the qualifications and experience of the IQRE and the primary technical persons of D&M, McDaniel and Ryder Scott responsible for overseeing the estimate of the reserves, future production and income evaluation of Nexen's reserve estimates disclosed in the 2011 AIF.

## I. IQRE

Mr. Ian McDonald, being the IQRE, is the primary technical person responsible for overseeing the preparation of Nexen reserves and resource estimates, and assessing whether those estimates and related disclosures have been prepared in accordance with NI 51-101 and SEC regulatory requirements. Mr. McDonald holds a Bachelor of Applied Science in Mechanical Engineering from the University of British Columbia and is a registered Professional Engineer with APEGA. He is also a member of the SPE, the Oil & Gas Reserves Committee of the SPE, which co-authors COGEH, the COGEH Review Committee, the Canadian Association of Petroleum Producers Reserves Issue task force, World Petroleum Congress delegate of the Joint Committee on Reserves Evaluator Training (JCORET) and the UNECE Expert Group on Resource Classification. He meets all professional and Canadian legal requirements in regards to experience, education and professional membership associated with the role of the IQRE. With 30 years of experience in evaluation of oil and gas properties including 15 years for oil sands and 6 years for shale gas, he has in-depth knowledge of reserves estimation techniques and professional guidelines, and with SEC and NI 51-101 reserves regulations and related reporting requirements. Mr. McDonald is supported by approximately 120 engineers and geoscientists who are also considered qualified evaluators for the purposes of NI 51-101, the SEC, and PRMS.

Mr. McDonald has served as the IQRE since 2003. In the performance of his IQRE duties, Mr. McDonald relies on the experience and skills he has obtained from various other roles at Nexen and its predecessor company (Canadian Occidental Petroleum Ltd.), including:

- Corporate Reserves Manager (2001-2003) – this is what the IQRE job title was before NI 51-101 came into force and prompted the change. As Corporate Reserves Manager, Mr. McDonald's responsibilities were largely the same as they are now as IQRE.

- Manager of Corporate Performance and Business Support (1999-2001) – responsible for economic analysis of capital expenditure plans, major project proposals, and major acquisition and divestment activities. Key member of strategic planning and budgeting group for Nexen globally.

- Exploration Manager – Canadian Gas Operations (1997-1999) – responsible for Nexen's Canadian gas exploration program, including oversight of all geological, geophysical and engineering work associated with reservoir analysis, prospect identification, exploration drilling, appraisal and completion.

Engineering Manager (1994-1997) – responsible for execution of capital and operating budget for Canadian field production and processing operations, including oil and gas property assessment, economics, drilling programs (vertical and horizontal), and facilities design and optimization related to 30,000 boe/d of production.

Staff Engineer (1989-1993) – performed engineering and economic analysis on the asset base to strategically prioritize budget allocation. Participated as a project team member in the design and maintenance of both oil and gas facilities in Western Canada. Assisted with the design and supervision of drilling and completion programs for Canadian assets.

Field Production Engineer (1982-1988) – responsible for economic optimization of field production, including primary and enhanced recovery, facility additions, modifications and consolidation, drilling proposals, and analysis of acquisitions and dispositions. Particular expertise at pressure transient analysis and reserves assessment.

## II. D&M

Mr. Lloyd W. Cade is the primary technical person from D&M responsible for overseeing their firm's independent estimate of Nexen's reserves. D&M provides an independent opinion of Nexen's reserve estimates used in the 2011 AIF. Mr. Cade is a Senior Vice-President of D&M. He has worked at D&M since 1986. Mr. Cade has a Bachelor of Science degree in Mechanical Engineering (cum laude) from Kansas State University and is a registered Professional Engineer in the State of Texas. He is also a member of the SPE. Mr. Cade has over 29 years of experience in oil and gas reservoir studies and evaluations and 8 years of experience in evaluation of shale gas properties.

Based on his educational background, professional training and practical experience in the estimation and evaluation of petroleum reserves, Mr. Cade has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the SPE as of February 19, 2007.

## III.McDaniel

Mr. Philip Welch is the primary technical person from McDaniel responsible for overseeing their firm's independent estimate of Nexen's reserves. McDaniel provides an independent opinion of Nexen's reserve estimates used in the 2011 AIF. Mr. Welch is the President and Managing Director of McDaniel and a Director of McDaniels International Inc. He has worked at McDaniel since 1988. Mr. Welch has a Bachelor of Applied Science and Master of Applied Science degrees in Mechanical Engineering from the University of British Columbia and is a Professional Engineer registered with the APEGA. He is also a member of the SPEE and the SPE. Mr. Welch has over 23 years of experience in oil and gas reservoir studies and evaluations and 14 years of experience in the evaluation of oil sands properties.

## IV. Ryder Scott

Mr. Richard J. Savoie is the primary technical person from Ryder Scott responsible for overseeing their firm's independent estimate of Nexen's reserves. Ryder Scott provides an independent opinion of Nexen's reserve estimates in the 2011 AIF. Mr. Savoie, an employee of Ryder Scott since 1997, is a Senior Vice President and also serves as an Engineering Group Coordinator responsible for coordinating and supervising staff and consulting engineers of Ryder Scott in ongoing reservoir evaluation studies worldwide. Mr. Savoie earned a Bachelor of Science degree in Petroleum Engineering from Louisiana State University in 1968 and is a registered Professional Engineer in the State of Texas. Mr. Savoie is also a member of the SPE.

Based on his educational background, professional training and more than 43 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Savoie has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the SPE as of February 19, 2007.

# APPENDIX VI GENERAL INFORMATION

## 1. Responsibility Statement

This circular, for which the Directors of the Company collectively and individually accept full responsibility, includes particulars given in compliance with the Listing Rules for the purpose of giving information with regard to the Company. The Directors, having made all reasonable enquiries, confirm that to the best of their knowledge and belief the information contained in this circular is accurate and complete in all material respects and not misleading or deceptive, and there are no other matters the omission of which would make any statement herein or this circular misleading.

## 2. Disclosure of Interests

As at the Latest Practicable Date, the interests of each Director and chief executive of the Company in the equity or debt securities of the Company or any associated corporations (within the meaning of the SFO) which were required (i) to be notified to the Company and the Hong Kong Stock Exchange pursuant to Divisions 7 and 8 of Part XV of the SFO (including interests and short positions which they are taken or deemed to have under such provisions of the SFO), (ii) pursuant to section 352 of the SFO, to be entered in the register referred to therein or (iii) pursuant to the Model Code for Securities Transactions by Directors of Listed Issuers, to be notified to the Company and the Hong Kong Stock Exchange were as follows:

Interests in share options granted by the Company

| Name of grantee | Date of grant | Exercise price (HK$) | Underlying shares granted pursuant to options |
|---|---|---|---|
| Executive Directors | | | |
| Wu Guangqi | 31 Aug 2005 | 5.62 | 1,610,000 |
| | 14 June 2006 | 5.56 | 1,770,000 |
| | 25 May 2007 | 7.29 | 1,857,000 |
| | 29 May 2008 | 14.828 | 1,857,000 |
| | 27 May 2009 | 9.93 | 1,857,000 |
| | 20 May 2010 | 12.696 | 1,857,000 |
| Non-executive Directors | | | |
| Yang Hua | 24 February 2003 | 2.108 | 1,150,000 |
| | 5 February 2004 | 3.152 | 1,150,000 |
| | 31 August 2005 | 5.62 | 1,610,000 |
| | 14 June 2006 | 5.56 | 1,770,000 |
| | 25 May 2007 | 7.29 | 1,857,000 |
| | 29 May 2008 | 14.828 | 1,857,000 |
| | 27 May 2009 | 9.93 | 2,835,000 |
| | 20 May 2010 | 12.696 | 2,000,000 |

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APPENDIX VI GENERAL INFORMATION

| Name of grantee | Date of grant | Exercise price (HK$) | Underlying shares granted pursuant to options |
|---|---|---|---|
| Zhou Shouwei | 24 February 2003 | 2.108 | 1,750,000 |
| | 5 February 2004 | 3.152 | 1,750,000 |
| | 31 August 2005 | 5.62 | 2,450,000 |
| | 14 June 2006 | 5.56 | 2,700,000 |
| | 25 May 2007 | 7.29 | 2,835,000 |
| | 29 May 2008 | 14.828 | 2,835,000 |
| | 27 May 2009 | 9.93 | 1,800,000 |
| | 20 May 2010 | 12.696 | 1,800,000 |
| Wu Zhenfang | 31 August 2005 | 5.62 | 800,000 |
| | 14 June 2006 | 5.56 | 1,770,000 |
| | 25 May 2007 | 7.29 | 1,857,000 |
| | 29 May 2008 | 14.828 | 1,857,000 |
| | 27 May 2009 | 9.93 | 1,800,000 |
| | 20 May 2010 | 12.696 | 1,800,000 |
| Independent Non-executive Directors | | | |
| Chiu Sung Hong | 5 February 2004 | 3.152 | 1,150,000 |

Save as disclosed above, as at the Latest Practicable Date, none of the Directors and chief executive of the Company was interested in the equity or debt securities of the Company or any associated corporations (within the meaning of the SFO) which were required (i) to be notified to the Company and the Hong Kong Stock Exchange pursuant to Divisions 7 and 8 of Part XV of the SFO (including interests and short positions which they are taken or deemed to have under such provisions of the SFO), (ii) pursuant to section 352 of the SFO, to be entered in the register referred to therein or (iii) pursuant to the Model Code for Securities Transactions by Directors of Listed Issuers, to be notified to the Company and the Hong Kong Stock Exchange.

# APPENDIX VI GENERAL INFORMATION

## 3. Substantial Shareholders

As at the Latest Practicable Date, so far as was known to the Directors and chief executive of the Company, the persons, other than a Director or chief executive of the Company, who had an interest or a short position in the Shares and underlying Shares which would fall to be disclosed to the Company under the provisions of Divisions 2 and 3 of Part XV of the SFO were as follows:

| Name of substantial shareholder of the Company | Ordinary shares held | Approximate percentage of the total issued shares |
|---|---|---|
| CNOOC (BVI) | 28,772,727,268 | 64.45% |
| OOGC | 28,772,727,273 | 64.45% |
| CNOOC | 28,772,727,273 | 64.45% |

Note 1: CNOOC (BVI) is a direct wholly owned subsidiary of OOGC, which is a direct wholly owned subsidiary of CNOOC. Accordingly, CNOOC (BVI)'s interests are recorded as the interests of OOGC and CNOOC.

Note 2: As at the Latest Practicable Date, (1) Mr. Wang Yilin also served as director of CNOOC, OOGC and CNOOC (BVI) and held a management position at CNOOC; (2) Mr. Wu Guangqi and Mr. Wu Zhenfang also served as directors of OOGC and CNOOC (BVI) and held management positions at CNOOC; and (3) Mr. Yang Hua also served as director and held a management position at CNOOC.

All the interests stated above represent long positions. Save as disclosed above, the Directors and chief executive of the Company are not aware that there is any party who, as at the Latest Practicable Date, had an interest or a short position in the Shares and underlying Shares which would fall to be disclosed to the Company under the provisions of Divisions 2 and 3 of Part XV of the SFO.

## 4. Professional Qualifications and Consents

The following are the qualifications of the experts who have given their opinions or advices which are contained in this circular:

| Names | Qualifications |
|---|---|
| Ernst & Young | Certified public accountants |
| Deloitte Hong Kong | Certified public accountants |
| D&M | Independent technical consultant |
| McDaniel | Independent technical consultant |
| Ryder Scott | Independent technical consultant |

(a) As at the Latest Practicable Date, none of the above experts had any beneficial interest in the share capital of any member of the Group, or had any right, whether legally enforceable or not, to subscribe for or to nominate persons to subscribe for securities in any member of the Group and had any interest, either

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directly or indirectly, in any assets which had been, since 31 December 2011, being the date of the latest published audited accounts of the Company, acquired or disposed of by or leased to or are proposed to be acquired or disposed of by or leased to any member of the Group.

(b) Each of the above experts has given and has not withdrawn its written consent to the issue of this circular with inclusion of its opinions and letters, as the case may be, and the reference to its name included herein in the form and context in which it appears.

## 5. Service Contracts

As at the Latest Practicable Date, none of the Directors had entered into any service contract with the Company or any member of the Group referred to in Rule 13.68 of the Listing Rules (excluding contracts expiring or determinable by the employer within one year without payment of compensation (other than statutory compensation)).

## 6. Interests of Directors

(a) The Directors are not aware that any Director or his respective associate had, as at the Latest Practicable Date, any interest in any business which competes or is likely to compete, either directly or indirectly, with the business of the Group which would be required to be disclosed under the Listing Rules.

(b) No Director was materially interested in any contract or arrangement subsisting at the Latest Practicable Date which was significant to the business of the Enlarged Group taken as a whole.

(c) Since 31 December 2011, being the date of the latest published audited consolidated accounts of the Company, none of the Directors has, or has had, any direct or indirect interest in any assets which have been acquired or disposed of by or leased to or which are proposed to be acquired, disposed of by or leased to, any member of the Enlarged Group.

## 7. Material Contracts

Save as disclosed below, no material contracts (not being contracts entered into in the ordinary course of business carried out by the Enlarged Group) had been entered into by any member of the Enlarged Group within the two years preceding the Latest Practicable Date:

(a) the Arrangement Agreement; and

(b) the underwriting agreement dated February 28, 2012 relating to the public offering of the Cumulative Redeemable Class A Rate Reset Preferred Shares, Series 2 entered into by Nexen, TD Securities Inc., Scotia Capital Inc., RBC Dominion Securities Inc., CIBC World Markets Inc., BMO Nesbitt Burns Inc., National Bank Financial Inc., Desjardins Securities Inc. and HSBC Securities (Canada) Inc..

## 8. Litigation

Save for the Complaint disclosed in subsection (e) of the section entitled "Indebtedness Statement – Contingencies" in Appendix I to the circular, as at the Latest Practicable Date, neither the Company nor any of its subsidiaries was engaged in any litigation, arbitration or claim of material importance and no litigation, arbitration or claim of material importance is known to the Directors to be pending or threatened against the Group as at the Latest Practicable Date.

As at the Latest Practicable Date, to the best of the Director's knowledge, information and belief, neither Nexen nor any of its subsidiaries was engaged in any litigation, arbitration or claim of material importance and no litigation, arbitration or claim of material importance is known to the Directors or Nexen to be pending or threatened against Nexen Group as at the Latest Practicable Date.

## 9. General

(a) The registered office of the Company is situated at 65th Floor, Bank of China Tower, 1 Garden Road, Hong Kong.

(b) The Company's registrar is Hong Kong Registrars Limited of Shops 1712-1716, 17th Floor, Hopewell Centre, 183 Queen's Road East, Wanchai, Hong Kong.

(c)The joint company secretaries of the Company are Mr. Zhong Hua, a senior engineer, and Ms. Tsue Sik Yu, an associate member of both the Institute of Chartered Secretaries and Administrators and the Hong Kong Institute of Chartered Secretaries.

(d)The English text of this circular shall prevail over the Chinese text in the case of any inconsistency.

## 10. Documents Available For Inspection

Copies of the following documents will be available for inspection during normal business hours on Monday to Friday (other than public holidays) at the offices of Davis Polk & Wardwell at 18th Floor, The Hong Kong Club Building, 3A Chater Road, Hong Kong, from the date of this circular for a period of 14 days:

(a) the memorandum of association and articles of association of the Company;

(b)the material contracts referred to in paragraph headed "Material Contracts" in this appendix;

(c) the published annual reports of the Company for each of the financial years ended 31 December 2010 and 31 December 2011;

(d) the interim report of the Company for the six months ended 30 June 2012;

# APPENDIX VI GENERAL INFORMATION

(e) the audited financial information of Nexen Group for the year ended 31 December 2010 (with 2009 comparative financial statements) prepared under Canadian GAAP as set out in Appendix II to this circular;

(f) the audited financial information of Nexen Group for the year ended 31 December 2011 and the unaudited (but reviewed) financial information for the six months ended 30 June 2012 prepared under IFRS as set out in Appendix II to this circular;

(g)the unaudited adjusted consolidated statements of income and unaudited adjusted consolidated balance sheets of Nexen under the Company's policies as set out in Appendix II to this circular;

(h)the report from Ernst & Young in relation to the unaudited pro forma financial information of the Enlarged Group as set out in Appendix III of this circular;

(i) the opinion letters of Independent Reserve Evaluators as set out in Appendix IV to this circular;

(j)the letters of consent referred to in the section headed "Professional Qualifications and Consents" in this appendix;

(k)the circular of the Company dated 12 April 2012 in respect of explanatory statement relating to general mandates to issue securities and repurchase shares and re-election of directors;

(l)the circular of the Company dated 3 August 2012 in respect of connected transaction relating to the coalbed methane resources exploration and development cooperation agreement;

(m)the circular of the Company dated 24 October 2012 in respect of revised caps for relevant categories of the continuing connected transactions in respect of 2012 and 2013; and

(n) this circular.

Exhibit 99.2

20 December 2012

Dear Non-registered holder (1),

CNOOC Limited (the "Company")
–Notice of publication of Circular ("Current Corporate Communications")

The English and Chinese versions of the Company's Current Corporate Communications are available on the Company's website at www.cnoocltd.com and the HKExnews's website at www.hkexnews.hk. You may access the Current Corporate Communications by clicking "Investor Relations" on the home page of our website, then selecting "Name of document" under "Announcement" and viewing them through Adobe® Reader®or browsing through the HKExnews's website.

If you want to receive a printed version of the Current Corporate Communications, please complete the Request Form on the reverse side and return it to the Company c/o Hong Kong Registrars Limited (the "Hong Kong Share Registrar") by using the mailing label at the bottom of the Request Form (no need to affix a stamp if posted in Hong Kong; otherwise, please affix an appropriate stamp). The address of the Hong Kong Share Registrar is 17M Floor, Hopewell Centre, 183 Queen's Road East, Wanchai, Hong Kong. The Request Form may also be downloaded from the Company's website at www.cnoocltd.com or the HKExnews's website at www.hkexnews.hk.

Should you have any queries relating to any of the above matters, please call the Company's telephone hotline at (852) 2862 8688 during business hours from 9:00 a.m. to 6:00 p.m. Monday to Friday, excluding public holidays or send an email to Cnooc.ecom@computershare.com.hk.

Yours faithfully,
By order of the Board
CNOOC Limited
Zhong Hua
Joint Company Secretary

Note: (1) This letter is addressed to Non- registered holders ("Non- registered holder" means such person or company whose shares are held in The Central Clearing and Settlement System (CCASS) and who has notified the Company from time to time through Hong Kong Securities Clearing Company Limited to receive Corporate Communications). If you have sold or transferred your shares in the Company, please disregard this letter and the Request Form on the reverse side.

To: CNOOC Limited (the "Company") (Stock Code: 00883)
c/o Hong Kong Registrars Limited
17M Floor, Hopewell Centre, 183 Queen's Road East,
Wanchai, Hong Kong

I/We would like to receive the Corporate Communications* of the Company ("Corporate Communications") in the manner as indicated below:

Notes:

1. Please complete all your details clearly.
2. This letter is addressed to Non-registered holders ("Non-registered holder" means such person or company whose shares are held in The Central Clearing and Settlement System (CCASS) and who has notified the Company from time to time through Hong Kong Securities Clearing Company Limited to receive Corporate Communications).
3. Any form with more than one box marked(X), with no box marked(X), with no signature or otherwise incorrectly completed will be void.
4. The above instruction will apply to the Corporate Communications to be sent to you until you notify to the Company c/o Hong Kong Registrars Limited to the contrary or unless you have at anytime ceased to have holdings in the Company.
5. For the avoidance of doubt, we do not accept any other instruction given on this Request Form.

*Corporate Communications includes but not limited to (a) the directors' report, its annual accounts together with a copy of the auditors' report and, where applicable, its summary financial report; (b) the interim report and, where applicable, summary interim report; (c) a notice of meeting; (d) a listing document; (e) a circular; and (f) a proxy form.