

# ANNUAL INFORMATION FORM



Horn River Basin, British Columbia

## ANNUAL INFORMATION FORM

General Information	1
Presentation of Information	3
Corporate Structure	4
Business Overview	4
Oil and Gas	7
Conventional Exploration and Development	9
Oil Sands	17
Unconventional Gas	22
Energy Marketing	24
Chemicals	25
Reserves, Production and Related Information	25
Environmental and Regulatory Matters	37
Employees	41
Risk Factors	41
Capital Structure	51
Market for Securities	53
Directors	55
Audit Committee Information	57
Executive Officers	59
Other	60
Appendix A—Audit and Conduct Review Committee Mandate	63

# 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
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
PSC™	=	Premium Synthetic Crude™	NYMEX	=	New York Mercantile Exchange

## GENERAL INFORMATION

In this AIF, we refer to oil and gas in common units called barrel of oil equivalent (boe). A boe is derived by converting 6,000 cubic feet of gas to one barrel of oil (6 mcf/1 bbl). This conversion may be misleading, particularly if used in isolation, as the 6 mcf/1 bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the wellhead.

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
2006	0.8581	0.8818	0.9099	0.8528
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

On January 31, 2011, the noon-day exchange rate was US\$0.9978 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 facilities 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; future cost recovery oil revenues from our Yemen operations; the expectation of negotiating of an extension to certain of our production sharing agreements; the expectation of our ability to comply with the new safety and environmental rules enacted in the US 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” are forward-looking statements, as they involve the implied assessment, based on estimates and assumptions that the reserves 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, 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 which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: 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 Disclosures About Market Risk” in our

management's discussion and analysis. 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 and, except as required by law, 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.

## PRESENTATION OF INFORMATION

In this Annual Information Form, 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 in tabular format. The information contained in this AIF is dated December 31, 2010, unless otherwise indicated.

### Explanatory Note on Filing Changes

Nexen is listed on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE). Commencing in 2011 with our 2010 year-end disclosures, our annual disclosures will be in accordance with Canadian requirements and filed with the Securities and Exchange Commission (SEC) on Form 40-F, through the Multi-Jurisdictional Disclosure System available to Canadian reporting issuers. In previous

years, we voluntarily used the Form 10-K (and related forms) to report our annual disclosures. Although the differences are substantively minor, we believe that basing our quarterly and annual disclosures on Canadian standards will enhance comparability of our information with that of our Canadian peers who generally report on this basis.

Until 2010, we had been relying on an exemption by Canadian securities regulators which allowed us to prepare and disclose reserves and related information in accordance with SEC requirements rather than National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (NI 51-101). Under a new exemption, granted in December 2010, we are now permitted to prepare and disclose reserves and related information in accordance with SEC requirements in addition to NI 51-101 requirements. We have chosen to continue to report our reserves and related information in accordance with SEC requirements in our AIF, management's discussion and analysis (MD&A) and Consolidated Financial Statements. Reserves and related information prepared in accordance with NI 51-101 is separately filed on the system for Electronic Document Analysis and Retrieval (SEDAR) at [www.sedar.com](http://www.sedar.com) under our profile. Canadian investors should read the "Special Note to Canadian Investors" on page 34.

### 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 Canadian generally accepted accounting principles (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 presented in our MD&A.

### 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. For information regarding our adoption of IFRS, refer to the "New Accounting Pronouncements" section of our MD&A.

## 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, their jurisdictions of incorporation and the percentage of securities beneficially owned, controlled or directed by us as at December 31, 2010 are as follows:

Name of Subsidiary	Jurisdiction of Incorporation/ Formation/Continuation	Percentage of Securities Owned, Controlled or Directed
Nexen Petroleum U.K. Limited	England & Wales	100%
Nexen Petroleum Nigeria Limited	Nigeria	100%
Nexen Petroleum Offshore USA Inc.	Delaware	100%
Nexen Marketing	Alberta	100%
Canadian Nexen Petroleum Yemen	Yemen	100%
Nexen Oil Sands Partnership	Alberta	100%

## 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

**Choice—it's what companies and investors value. Whether it's how we allocate capital, fund our growth, or invest in projects that make the most sense over the long term, choice is key. Our strategy is to build a sustainable energy company focused on delivering on execution and exploiting our existing three key growth areas: i) conventional exploration and development; ii) oil sands; and iii) unconventional gas.**

#### Conventional Exploration and Development

Our conventional exploration and development assets are comprised of large acreage positions in select basins including the 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. Our global exploration team prioritizes investments in prospects that we expect will generate the highest value in our selected basins of choice.

In the 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. We have since made several other discoveries including the

Golden Eagle area, Blackbird and Rochelle. We are actively exploring the basin including relatively under-explored areas such as west of the Shetland Islands and offshore Norway.

In the deep-water Gulf of Mexico, we made several significant discoveries including Gunnison, Aspen, Knotty Head, Wrigley and Longhorn. More recently, we made significant discoveries at Appomattox and Vicksburg. We are a large leaseholder in the Gulf. The deep-water Gulf is near infrastructure and continental US markets.

We have several significant discoveries offshore West Africa, including Usan, Usan West and Ukot, as well as at Owowo, offshore Nigeria. Development of the Usan field is progressing with construction of a floating production and storage offloading (FPSO) vessel and subsea facilities for expected first production in 2012.

## Oil Sands

Our oil sands investments include interests in the Long Lake project, the Syncrude joint venture and 675,000 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 develops and produces synthetic crude oil from mining bitumen-saturated sands.

In 2001, we formed a 50/50 joint venture with OPTI Canada Inc. (OPTI) to develop, produce and upgrade bitumen on joint lands in the Athabasca oil sands. Production here utilizes our patented OrCrude™ technology, which we expect will ultimately result in a significant margin advantage over conventional oil sands extraction and upgrading. Construction of the Long Lake project was completed in 2008 and we began producing PSC™ oil in 2009. In early 2009, we acquired an additional 15% interest in the Long Lake project and joint venture lands from OPTI, increasing our ownership level to 65%. Following this acquisition, we are now responsible for operating both the steam-assisted-gravity-drainage (SAGD) bitumen extraction process and the upgrader for Phase 1 as well as for future phases.

## Unconventional Gas

Our unconventional gas strategy is focused primarily on the Horn River Basin in northeast British Columbia. The Horn River Basin is a significant shale gas play with high resource density and strong well productivity. We have over 300,000 acres of shale gas lands in the Horn River, Cordova and Liard shale gas basins in northeast British Columbia, with a 100% working interest in each. We have a substantial land position in the Horn River Basin, with approximately 90,000 acres in the Dilly Creek area.

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.

## Three-Year Look Back

<b>2008</b>	<ul style="list-style-type: none"><li>• Achieved record financial results, generating cash flow from operations of \$4.2 billion and net income of \$1.7 billion</li><li>• Received government approval for the Usan development, offshore West Africa</li><li>• Started bitumen operations at Long Lake</li><li>• Acquired a significant land position in the Horn River shale gas play</li></ul>
<b>2009</b>	<ul style="list-style-type: none"><li>• Generated cash flow from operations of \$2.2 billion and net income of \$536 million</li><li>• Discovered the Hobby field in the UK North Sea, the first discovery of our Golden Eagle area</li><li>• Acquired an additional 15% working interest in the Long Lake project and completed first major turnaround to address steam reliability issues</li><li>• Produced first PSC™ from Long Lake</li><li>• Issued \$1 billion of 10-year and 30-year senior notes</li><li>• Discovered Owowo field, offshore West Africa</li></ul>
<b>2010</b>	<ul style="list-style-type: none"><li>• Generated strong cash flow from operations of \$2.1 billion and net income of \$1.2 billion</li><li>• Discovered the Appomattox field in the deep-water Gulf of Mexico</li><li>• Disposed of non-core, heavy oil properties in Western Canada for \$939 million</li><li>• Divested of non-core marketing businesses including North American natural gas marketing</li><li>• Doubled bitumen production at Long Lake with improved steam reliability</li><li>• More than doubled our British Columbia shale gas acreage, adding lands in the Cordova and Liard basins</li></ul>

In early 2011, we disposed of our investment in Canexus for net proceeds of \$458 million.

During the remainder of 2011, we expect the following changes to our businesses:

- UK North Sea—sanctioning development of our discoveries in the Golden Eagle area, Blackbird and Rochelle, as well as continuing to explore the North Sea.
- US Gulf of Mexico—resuming exploration activity once drilling permits are received.
- Offshore West Africa—advancing construction and commissioning of the Usan project and exploring additional offshore acreage.
- Yemen—negotiating a potential five-year extension of the Masila block production sharing agreement.
- Long Lake—continuing to ramp-up bitumen production at Long Lake and assessing development plans of future oil sands phases.
- Shale Gas—bringing a nine-well pad on stream and initiating construction of an 18-well pad.

## POSITIONED FOR SUCCESS—FOCUSED ON VALUE

**Our goal is to grow long-term value for our shareholders responsibly. Key drivers to grow value are increasing reserves, production, cash flow and net income on a cost-effective basis over the long term. Success in our three strategic growth areas and existing producing properties delivers this growth. Today, we are building sustainable businesses in the North Sea, Western Canada, Gulf of Mexico, and offshore West Africa, capitalizing on the following corporate strengths:**

### RESOURCE INVENTORY

- Diversification—our assets are geographically diverse and we produce oil and gas, onshore and offshore. We have large conventional and unconventional legacy assets in our portfolio, which allows us to pursue value opportunities in varying economic environments.
- Significant captured resource—we have key resource plays with a low cost of entry. Our Long Lake project is developing only 10% of our oil sands leases in the Athabasca oil sands; we are an early player in the Horn River Basin shale gas play in northeast British Columbia; and we hold significant unexplored acreage in the Gulf of Mexico, the North Sea and offshore West Africa.
- Production weighted to crude oil—current production is approximately 85% and proved reserves are approximately 92% weighted to crude oil, respectively. The majority of our crude oil production is priced relative to international benchmarks such as Brent.

### STRUCTURAL GROWTH

- Focus on growth—significant production growth is expected to come from identified projects currently under development. We are successful explorers with undeveloped discoveries at Knotty Head and Appomattox in the Gulf of Mexico, the Golden Eagle area in the UK North Sea, and Usan and Owowo, offshore Nigeria. We are ramping up production at Long Lake and continue to advance our shale gas play in the Horn River Basin. We expect to add about 70,000 boe/d of new production over the next 24 months as we bring on Usan, UK tiebacks, shale gas and ramp up at Long Lake. We expect further upside from a successful Yemen contract extension and development of our existing discoveries.

## FINANCIAL STRENGTH

- Strong financial position—we have access to approximately \$4 billion of liquidity through cash and undrawn committed credit facilities that allow us to proceed with investments at our pace and to take advantage of opportunities as they arise.
- Industry-leading cash netbacks—position us well to withstand lower commodity prices.

## SUPERIOR TALENT

- International expertise—we are an international operator with a proven track record of successful business ventures in Yemen, Canada, the United States, the United Kingdom, Nigeria and Colombia.
- Employer of choice—proven ability to attract and retain talent (Top 100 Employer for 2011 in the annual Media Corp ranking survey).
- Skilled workforce—we significantly enhanced our technical skills over the last few years by hiring highly experienced employees for our oil sands, shale gas and Gulf of Mexico businesses.

## HOW WE DO BUSINESS

- Sustainable business practices—leveraging our strength in business practices such as health, safety, environment and social responsibility (HSE&SR) to access opportunities and responsibly create and demonstrate both long-term benefits and value growth for our investors, for the communities in which we operate and for other stakeholders. This makes us a desired business partner and/or joint venture operator and welcome in the communities in which we operate.
- Leadership—industry leader in governance, community relations and environmental stewardship. We received several external recognition and awards for our governance practices and disclosures.

## OIL AND GAS

We have oil and gas operations in the UK North Sea, US Gulf of Mexico, western Canada, Yemen, offshore West Africa, Colombia, and Norway. We also have operations in Canada's Athabasca oil sands which produce synthetic crude oil. We operate most of our production and continue to develop new growth opportunities in each area by actively exploring and applying technology.

In this AIF, we provide estimates of remaining quantities of proved and probable oil, synthetic oil and natural gas reserves (oil and gas reserves) for our various properties as at December 31, 2010. These reserves estimates and related disclosures have been prepared in accordance with the definitions and disclosure requirements prescribed by the SEC. We have also prepared reserves estimates in accordance with NI 51-101. Our Statement of Reserves Data and Other Oil and Gas Information on Form 51-101F1 has been filed at the same time as this AIF on SEDAR at [www.sedar.com](http://www.sedar.com). Reserve estimates and disclosures prepared in accordance with SEC requirements differ from reserves estimates prepared in accordance with NI 51-101. Significant qualitative differences between SEC and NI 51-101 reserves estimates and disclosures are described in the section entitled "Special Note to Canadian Investors" on page 34.

Our proved and probable reserve estimates have been internally prepared. For our reserves estimates prepared in accordance with SEC requirements, we had 99% of our proved reserves before royalties (99% after royalties) assessed (either evaluated or audited as described on pages 31 to 34) by independent reserves consultants. Their assessment of the proved reserves are 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 99% of our proved plus probable oil and gas reserves before royalties (99% after royalties) assessed by independent reserves consultants. By definition, probable reserves must be determined together with proved reserves (see definition on page 30). 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 are 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 31 to 34 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 have captured an inventory of significant 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.

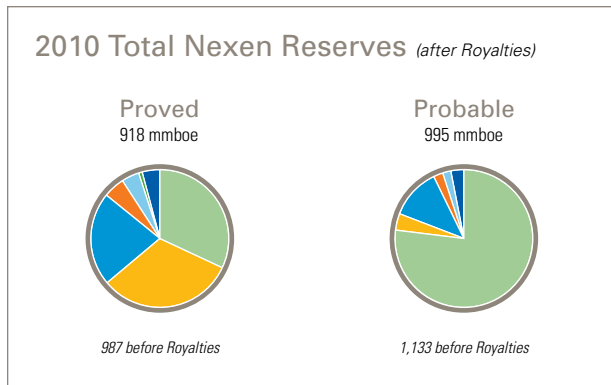
The prices we receive for our oil and gas products are determined by global crude oil and natural gas markets and regional dynamics, all of which can be volatile. With many alternative customers, the loss of any one customer is not expected to have a significantly adverse effect on the price of our products 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 and competitive environments and risk factors associated with each country.

Our oil and gas operations are broken down geographically into the UK North Sea, Canada, Syncrude, US Gulf of Mexico, Yemen and Other International (currently Colombia, offshore West Africa and Norway). Results from our Long Lake project and shale gas are included in Canada. We also report on our energy marketing operations.

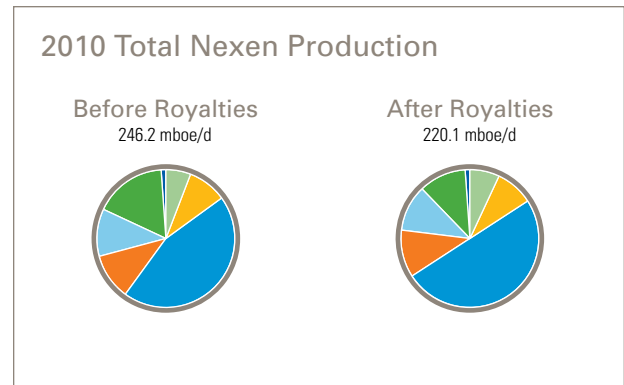
Production, revenues, net income, capital expenditures and identifiable assets for these segments appear in Note 23 to the Consolidated Financial Statements and in our MD&A. Reserves and related information for our oil and gas operations are prepared in accordance with SEC disclosure standards in this AIF. Reserves prepared in accordance with Canadian disclosure standards as set out in NI 51-101 are available on Form 51-101F1, filed in Canada on SEDAR at [www.sedar.com](http://www.sedar.com).

## NEXEN CONSOLIDATED RESERVES AND PRODUCTION

In the charts below, our consolidated proved and probable reserves as at December 31, 2010 are presented, along with our oil and gas production for the year ended December 31, 2010. Further information on our reserves related information is found on page 25 of this AIF.



■ Long Lake    ■ Syncrude    ■ United Kingdom    ■ Other  
■ Canada    ■ United States    ■ Yemen

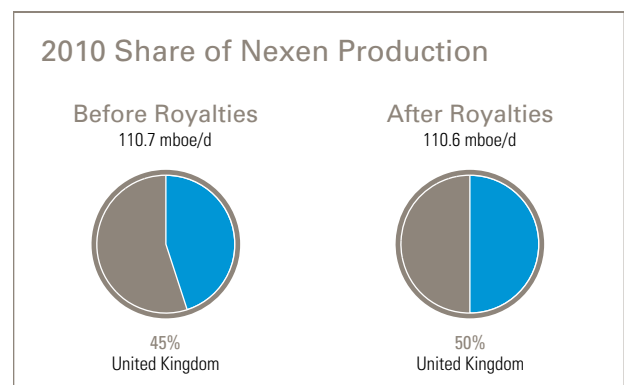
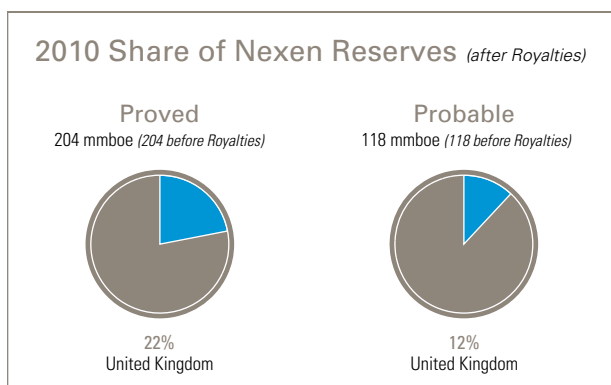


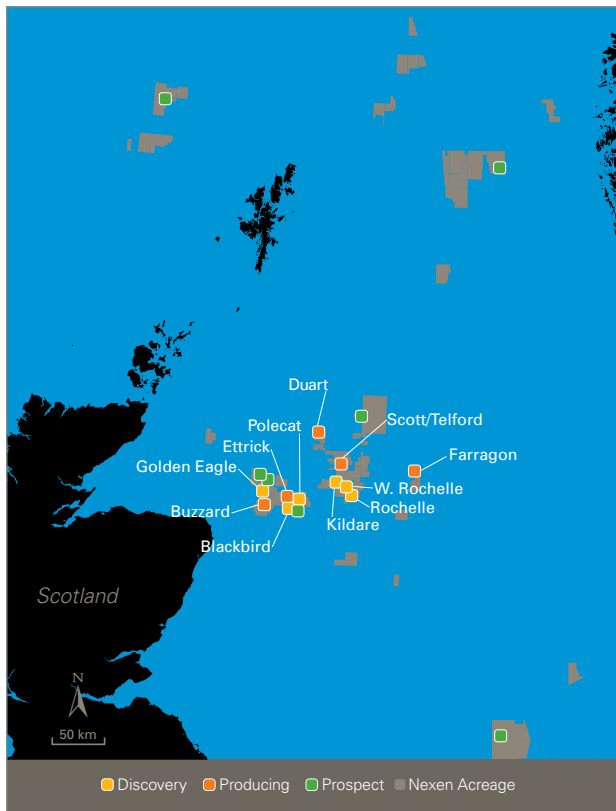
■ Long Lake    ■ Syncrude    ■ United Kingdom    ■ Other  
■ Canada    ■ United States    ■ Yemen

## CONVENTIONAL EXPLORATION AND DEVELOPMENT

### United Kingdom (UK)

- We are the second largest oil producer in the UK North Sea.
- We are progressing our significant discovery in the Golden Eagle area, with development sanctioning targeted in 2011.
- We continue to actively explore the North Sea, with six exploration and appraisal wells planned for 2011.





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 and a 79.7% interest in the Ettrick field, along with interests in several undeveloped discoveries and more than 954,000 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 production sources. To do this, we identify exploration and exploitation opportunities near existing infrastructure that can be tied-in economically in a short time period.

## BUZZARD

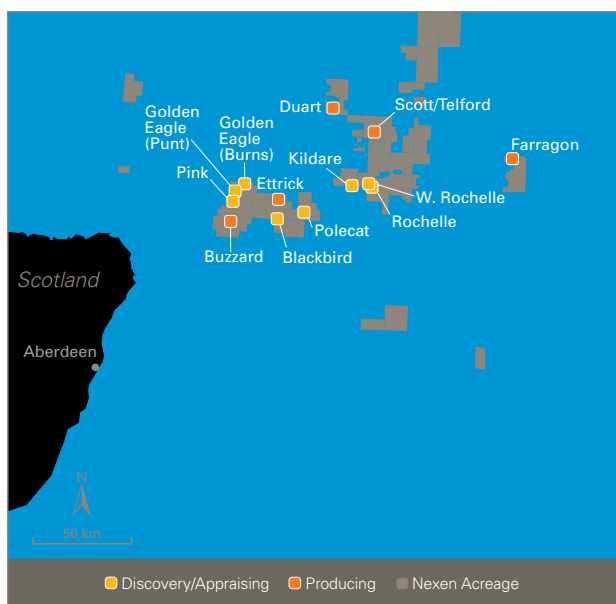
Buzzard is the largest discovery in the UK North Sea in over a decade. It was discovered in 2001 and came on stream in early 2007.

The Buzzard field is located about 60 miles northeast of Aberdeen in the Outer Moray Firth, central North Sea, in 317 feet of water. 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. In late 2010, a fourth platform with production-sweetening facilities to handle higher levels of hydrogen sulphide was brought on line. 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 26 of these wells to date and 16 of these wells are now available for production. A further six wells will be available for production in early 2011 due to the additional production-sweetening facilities. Our share of production in 2010 was 80,500 boe/d. We expect to drill four additional development wells in 2011.

## SCOTT/TELFORD

Scott and Telford are producing fields with additional exploitation opportunities. Scott was discovered in 1987 and began producing in September 1993, while Telford was discovered in 1991, tied back to the Scott platform and came on stream in 1996. Most of our oil and gas from the 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. In recent years, the Scott platform has undergone several significant maintenance turnarounds and facilities upgrades to improve reliability and extend facility life. Recently, successful extension drilling of the Telford field exceeded our expectations and extended the field's proved reserves. Late in 2010, we acquired an additional 8.7% interest in the Telford field. The nearby Rochelle discovery is planned to be tied back to the Scott platform by early 2012. Scott/Telford produced 13,900 boe/d (net to us) in 2010.



## ETTRICK

Ettrick is a producing field, originally discovered in 1981 and brought on stream in 2009. Oil and gas is produced from the fields through subsea wells tied back to an FPSO. During 2010, production from the field was ramped up to full rates. 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. Production from the nearby Blackbird field is planned to be tied back to the Ettrick FPSO in 2012. Our 2010 share of production was 14,500 boe/d.

## OTHER

We have interests in two smaller non-operated fields in the UK North Sea. The Farragon field was brought on stream in late 2005. In 2007, the Duart field began producing oil from a single well tied back to a third-party platform.

## EXPLORATION AND UNDEVELOPED ASSETS

We continue to actively explore in the UK North Sea and hold several undeveloped discoveries on operated blocks near Scott, Buzzard and Ettrick as follows:

Field	Interest (%)	Operator Status	Comments
Blackbird	80	operated	discovery near Ettrick; tie back to Ettrick FPSO by 2012
Polecat	40	operated	discovery near Buzzard; evaluating development alternatives
Golden Eagle	37	operated	discovery near Buzzard; development sanctioning in 2011
Hobby	37	operated	discovery near Golden Eagle; development sanctioning in 2011
Pink	37	operated	discovery near Golden Eagle; development sanctioning in 2011
Kildare	50	operated	discovery near Scott; evaluating development alternatives
Rochelle	44	non-operated	discovery near Scott; tie back to Scott platform by 2012
West Rochelle	TBD	non-operated	discovery near Scott, evaluating development alternatives

In 2007, we discovered hydrocarbons at Golden Eagle, followed by Pink in 2008, and early in 2009 we made a discovery at Hobby. We refer to these three discoveries as the Golden Eagle area. During 2009, we successfully completed a comprehensive appraisal program of these discoveries, which included drilling nine appraisal wells, two drill-stem tests and one injection test. In 2010, we expanded our acreage in this area and progressed development plans of the discoveries. In 2011, we plan to complete appraisal work, explore additional acreage and sanction the development plan. With the success achieved to date, we expect the Golden Eagle area will become a significant asset over the next few years.

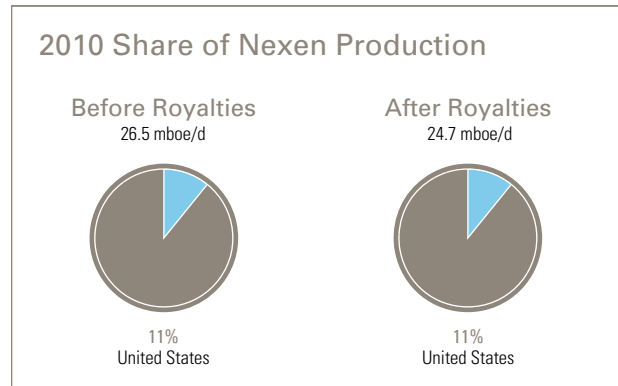
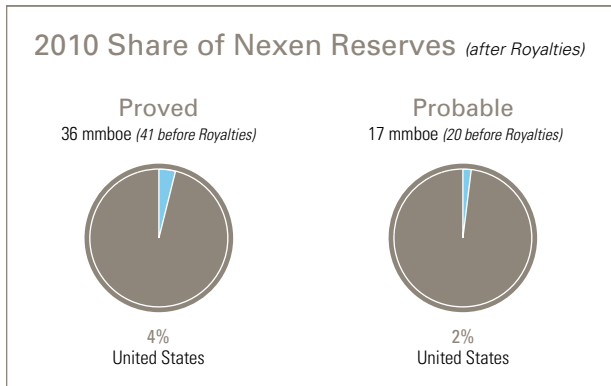
In the UK North Sea, we plan to drill a total of four exploration wells and two appraisal wells in 2011.

## FISCAL TERMS

In the UK, new discoveries pay no royalties and result in cash netbacks that are higher than our company average. The Scott field is subject to Petroleum Revenue Tax (PRT), although no PRT is payable until available oil allowances have been fully utilized, which is expected to occur in 2011. Once payable, PRT is levied at 50% of cash flow after capital expenditures, operating costs and an oil allowance for the field. PRT is applicable to fields receiving development consent prior to March 1993. Our other fields in the UK North Sea are not subject to PRT. PRT is deductible for corporate income tax purposes. The UK corporate income tax rate on oil and gas activities is 30% of taxable income, and oil and gas activity is subject to a 20% supplemental charge.

## United States (US) — Gulf of Mexico

- We are a significant leaseholder in the deep-water Gulf of Mexico, a world-class basin with excellent potential.
- We are appraising our Appomattox discovery in the emerging Norphlet play.
- We are advancing our Knotty Head discovery towards project sanction.



The 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 sources for oil and gas. While costs of deep-water exploration are typically higher, prospects generally have multiple sands and higher production rates—factors that enhance economics. The technology to find, drill and develop discoveries is rapidly progressing. 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 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 acreage to high-grade prospects, hired new employees with significant Gulf of Mexico oil and gas experience and gained access to two new-build deep-water drilling rigs. These activities have yielded major discoveries in both plays and a high quality prospect portfolio to fuel further exploration.

Our current Gulf production and reserves are primarily concentrated in five deep-water and five shallow-water (shelf) areas.



### DEEP WATER

Most of our deep-water production comes from our 25% non-operated Longhorn field, our 50% non-operated Wrigley field, our 100% operated Aspen field, and our 30% non-operated Gunnison field. Our share of 2010 deep-water production before royalties was 18,200 boe/d (16,400 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 achieved production of approximately 200 mmcf/d gross (50 net to us) in 2010.

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.

Aspen is on Green Canyon Block 243 in 3,150 feet of water. The project was developed using subsea wells tied back to the third-party operated Bullwinkle platform 16 miles away and began producing in late 2002.

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. We achieved payout on Gunnison in December 2005, just two years after first production.

In 2007, we acquired three deep-water fields: i) Garden Banks Block 205; ii) Green Canyon 137; and iii) Green Canyon 6/50. These fields are in water depths between 700 and 1,100 feet. Production from Green Canyon 6/50/137 has been suspended as the third-party platform that processed our oil and gas was destroyed by Hurricane Ike in September 2008. During 2010, the lease on Green Canyon 137 expired. We are assessing our options to restore field production from Green Canyon 6/50, which may include building our own processing platform, a tie-back to a third-party platform or potentially divesting the asset.

## 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 (consisting of Blocks 65, 66 and 67) and West Delta. Given the mature nature of these assets and our focus on deep-water exploration, our 2011 capital investment on these assets is expected to be minimal.

## EXPLORATION AND UNDEVELOPED ASSETS

We hold approximately 207 blocks in the Gulf of Mexico and expect this acreage and future exploration opportunities to position us well for continued growth. Our undeveloped deep-water discoveries include:

Well	Interest (%)	Operator Status	Comments
Appomattox	20	non-operated	discovery; further appraisal required
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. Additional appraisal wells are planned to further delineate this discovery throughout 2011 once the US regulatory agencies issue necessary drilling permits. Elsewhere in 2010, we completed drilling a second appraisal well at Knotty Head and signed a letter of intent to jointly develop our discovery with the third-party Pony discovery on the offsetting block to the north. We plan to have an integrated project team in place in early 2011 to work on a joint development plan for both blocks.

In 2011, we plan to drill up to three exploration wells in the deep-water Gulf of Mexico, focusing on the Miocene sub-salt play.

The BP Macondo oil spill and the subsequent drilling moratorium did not impact our production in 2010, however, our exploration drilling programs are delayed as US regulatory agencies have not yet issued new Gulf of Mexico drilling permits. Subsequent to the drilling moratorium, new rules have been enacted in the US regarding improving the safety of offshore operations, safeguarding the environment, strengthening oil spill response, planning and capacity, advancing well containment capabilities, deep-water drilling procedures, wellbore integrity and blowout prevention. We expect to be able to comply with the new rules at a minimal incremental cost. We expect that drilling permits will be granted at a slower pace in the future than before the moratorium. We believe our drilling practices comply with the new regulatory requirements and expect to resume exploration drilling in 2011 once appropriate drilling permits are received.

### FISCAL TERMS

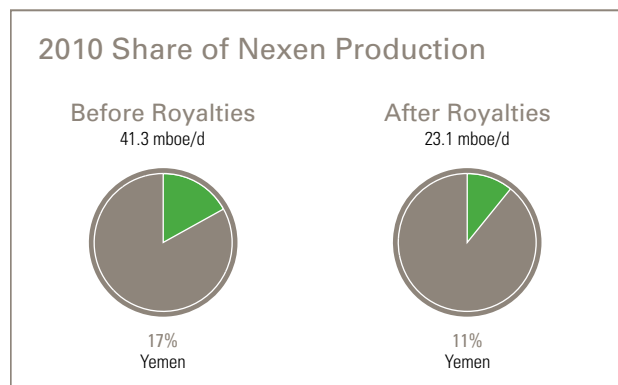
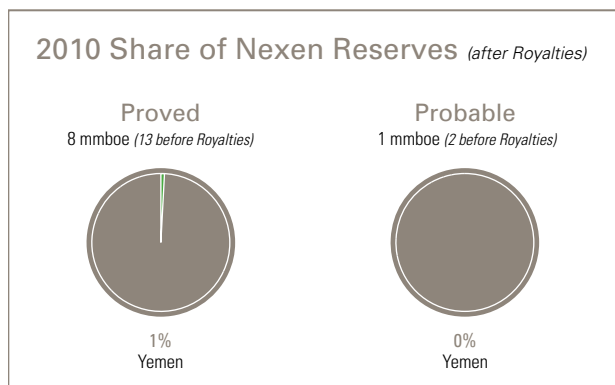
In 2010, royalty rates on our US production averaged 17% for shelf volumes and 3% for deep-water volumes. The US government increased royalty rates from 12.5 to 18% for new deep-water leases awarded after July 2007. Our Aspen and Gunnison fields are not subject to royalties on the first 87.5 mmbbl of production. Our Wrigley and Longhorn fields are not subject to royalties on the first 9 mmbbl of production if realized prices do not exceed certain price thresholds as determined by the regulators. Natural gas prices did not exceed the threshold in 2010 and, therefore, no royalties were due on these properties. US taxable income is subject to federal income tax of 35% and state taxes ranging from 0 to 12%.

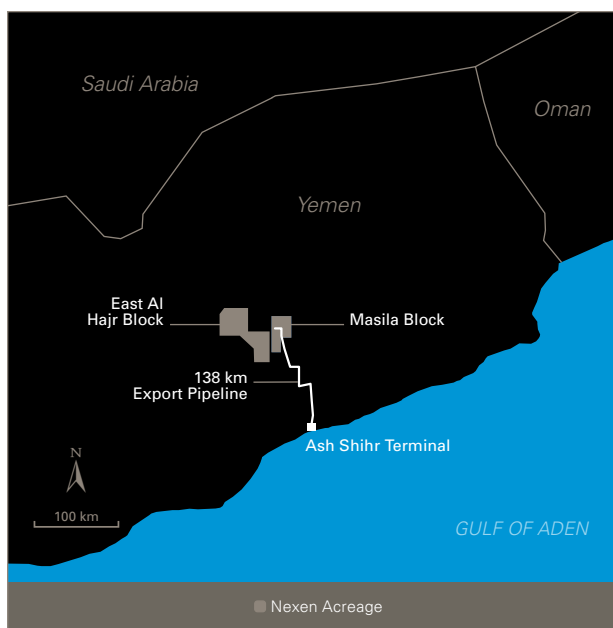
### Other International

- Our entry into Yemen kicked off our international expansion in the early 1990s, which provided us with other significant international opportunities.
- Development of the Usan field, offshore Nigeria is currently under construction. We have several discoveries and additional exploration prospects beyond Usan.
- We are leveraging international exploration and operating success with experience to pursue unconventional resources abroad.

### YEMEN

Yemen has been a significant international region for us since we first began production at Masila in 1993. We operate the country's largest oil project and have developed strong relationships with the government and local communities. Our strategy in Yemen is to maximize the value from our two existing producing blocks: Masila (Block 14) and East Al Hajr (Block 51). We are also reviewing our opportunities in Yemen for potential future exploration activities.





### Masila Block (Block 14)

We operate the Masila project with a 52% working interest. The Masila fields are mature but still hold significant value, generating cash flow in excess of capital requirements. Under the Masila Production Sharing Agreement (PSA) between the Government of Yemen and the Masila joint venture partners (Masila Partners), we have the right to produce oil from Masila to December 17, 2011. We are currently negotiating a five-year extension of the Masila PSA with the Yemen Government. There is no assurance that this extension will be received.

The first successful Masila exploratory well was drilled at Sunah in 1990, with additional discoveries quickly following at Hejjah and Camaal. Initial production began in July 1993. Masila crude oil averages 32° API at very low gas-oil ratios. Most of the oil is produced from the Upper Qishn formation, but we also produce from deeper formations, including the Lower Qishn, Upper Saar, Saar, Madbi, Basal Sand and Basement formations. Production is collected at our central processing facility (CPF), where water is separated for reinjection and oil is pumped to the Ash Shihr export terminal on the Indian Ocean and shipped to customers, primarily in Asia.

Production is divided into cost-recovery oil and profit oil. Cost-recovery oil provides for the recovery of all exploration, development and operating costs that are funded by the Masila Partners. Costs are recovered from a maximum of 40% of production each year, as follows:

Costs	Recovery
Operating	100% in year incurred
Exploration	25% per year for four years
Development	16.7% per year for six years

The remaining production is profit oil that is shared between the Masila Partners and the government and is calculated on a sliding scale based on production. The Masila Partners' share of profit oil ranges from 20 to 33%. The structure of the agreement moderates the impact on the Masila Partners' cash flows during periods of low prices, as we recover our costs first and then share any remaining profit oil with the government. The government's share of profit oil includes a component for Yemen income taxes paid by the Masila Partners at a rate of 35%. In 2010, the Masila Partners' share of production, including recovery of costs, was approximately 43%.

### 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 CPF, gathering system and a 22 km tie-back to our Masila export pipeline. Production commenced in November 2004.

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. We recognize both the government's share and TYCO's share of profit oil under the Block 51 PSA as royalties and taxes. The PSA expires in 2023 and we have the right to negotiate a five year extension. Under the Block 51 PSA, the EAH Partners pay a royalty ranging from 3 to 10% to the government depending on production volumes. The remaining production is divided into cost-recovery oil and profit oil. Cost-recovery oil provides for the recovery of all of the project's exploration, development and operating costs, funded solely by Nexen.

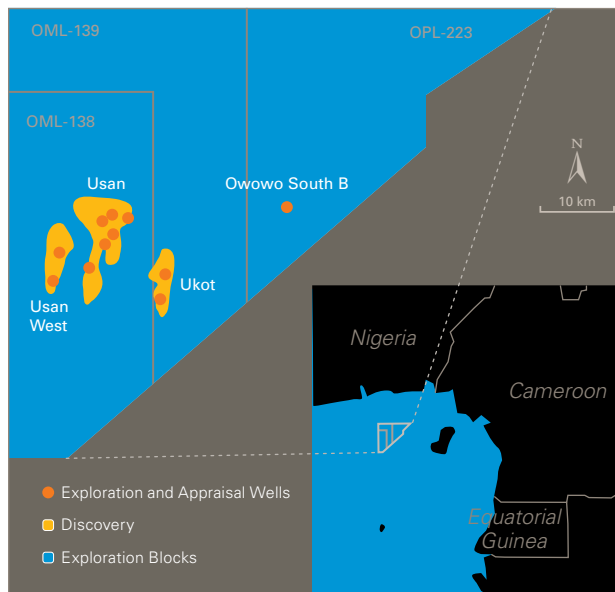
Costs are recovered from a maximum of 50% of production each year after royalties, as follows:

Costs	Recovery
Operating	100% in year incurred
Exploration	75% in year one, 25% in year two
Development	75% in year one, 25% in year two

The remaining production is profit oil that is shared between the EAH Partners and the government on a sliding scale based on production rates. The EAH Partners' share of profit oil ranges from 20 to 30%. The government's share of profit oil includes a component for Yemen income taxes paid by the EAH Partners at a rate of 35%. In 2010, the EAH Partners' share of Block 51 production, including recovery of past costs, was approximately 44%.

## NIGERIA

Offshore West Africa is a core area where we have several discoveries. It offers prolific reservoirs and multiple opportunities to invest in this oil-rich region. Our strategy here is to complete development of the Usan discovery and continue to explore our portfolio 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 600 to 3,500 feet. In 1998, we discovered the Ukot field and encountered three oil-bearing intervals. This was followed up by a successful appraisal well in 2003. In 2002, the Usan field was discovered and seven more successful wells confirmed that significant hydrocarbons exist on the block.

Development of the Usan field is progressing well and is expected to come on stream in 2012, ramping up to peak production rates of 180,000 bbls/d (36,000 bbls/d, net to us). Construction of the FPSO hull and subsea facilities continued in 2010 and the major topside modules were successfully installed onto the FPSO deck. The FPSO is now over 90% complete and will be capable of storing up to two million barrels of oil. We expect that our total investment in the Usan development will be approximately \$2 billion (net to us).

In 2008, we acquired an 18% non-operated interest in Block OPL-223, covering 230,000 acres, which provides us with future exploration potential on the adjacent block. In 2009, we completed drilling an exploration well in the southern portion of Block OPL-223. The Owowo South B-1 well was drilled in a water depth of 670 metres and is located 20 km northeast of the Usan field. Under the Production Sharing Contract governing OPL-223, the Nigerian National Petroleum Corporation is the concessionaire of the licence, which is operated by Total Exploration & Production Nigeria Ltd. We continue to explore offshore West Africa for potential prospects.

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 project.

## COLOMBIA

In 2000, we made a discovery at Guando on our 20% non-operated Boqueron Block, and production from Guando 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.

Production from Guando is subject to a royalty between 5 and 25% depending on daily production. In 2010, the royalty payable to the Colombian government averaged 8%. Colombian taxable income is subject to federal income tax of 33%.

We currently hold interests in one development block, three exploration and production blocks and two technical evaluation agreements 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 Chiquenquirá and Sueva exploration and production blocks, and a 100% interest in the Fomeque and Lower Villeta technical evaluation agreements.

## NORWAY

Norway is a natural extension of our conventional offshore growth strategy in the North Sea given our geological experience with the UK. The Norwegian continental shelf is characterized by well-developed infrastructure and potentially significant hydrocarbon resources. The Norwegian government incentivized the oil and gas industry to explore this area by providing a 78% cash tax refund on qualifying exploration expenditures to companies that are not taxable.

We hold working interests in nine exploration licences in the Norwegian North Sea. In 2010, we acquired additional seismic and drilled an unsuccessful exploration well. In 2011, we expect to drill at least one exploration well and continue to add to our portfolio through participation in annual licensing rounds and farm-ins. Norwegian oil and gas income is subject to a general corporate income tax rate of 28% plus an additional 50% special petroleum tax.

## OIL SANDS

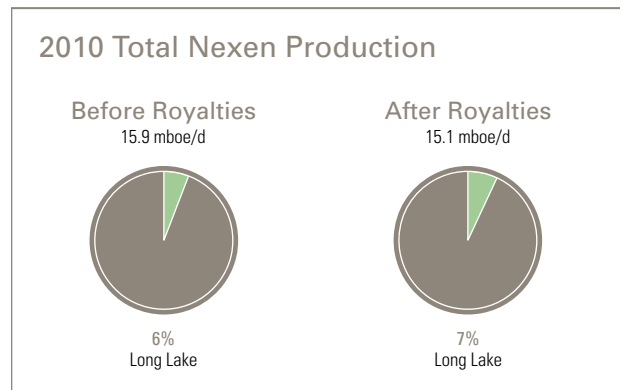
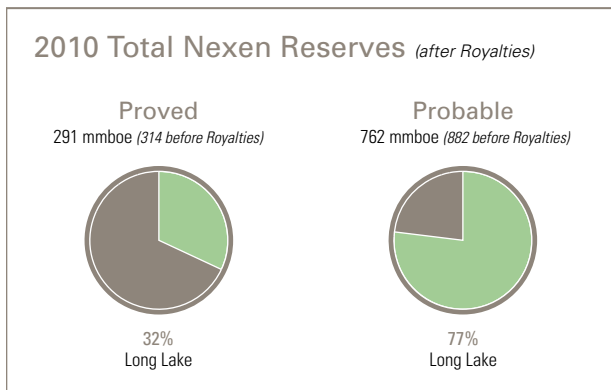
- Long Lake production and upgrading capacity continued to ramp up during the year.
- We have significant undeveloped acreage in the Athabasca oil sands, totaling over 675,000 acres (gross).
- Syncrude has been operating for over 30 years and provides steady predictable cash flows.

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 over the long-term. Our Long Lake project involves integrating SAGD bitumen production with field-upgrading technology to produce PSC™ for sale, and synthetic gas, which significantly reduces our need to purchase natural gas for operations. We also have a 7.23% investment in the Syncrude oil sands mining and upgrading operation as well as significant undeveloped acreage.

## Insitu Oil Sands

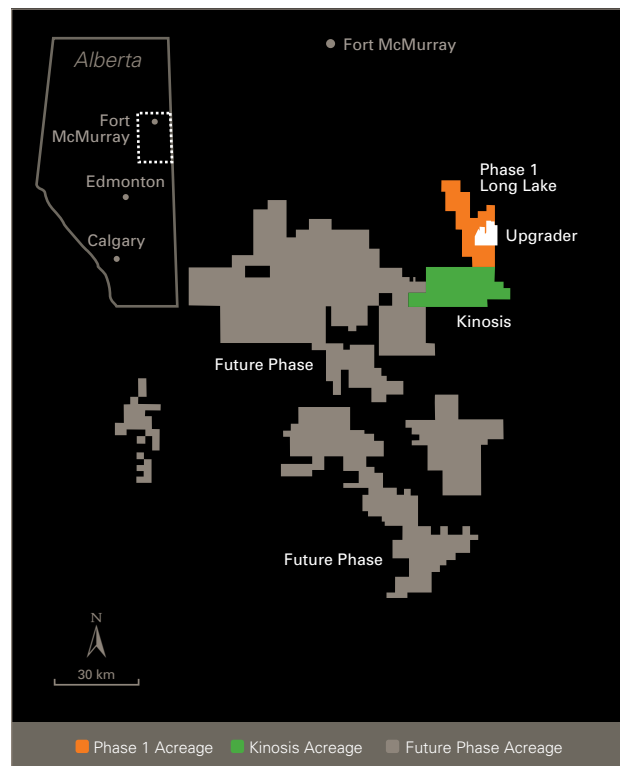
In 2001, we formed a 50/50 joint venture with OPTI to develop the Long Lake lease using SAGD for bitumen production and proprietary OrCrude™ technology for the first stage of upgrading. OPTI has the exclusive Canadian licence for the OrCrude™ technology. We acquired the exclusive right to use this technology 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 started mid 2008 and we began producing PSC™ 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 this acquisition, we are now responsible for operating both the SAGD bitumen extraction process and the upgrader for Phase 1 and future phases.



## SAGD AND UPGRADER INTEGRATION

The SAGD process involves drilling two parallel horizontal wells, with horizontal portions generally between 2,300 and 3,300 feet long, with about 16 feet of vertical separation. Steam is injected into the shallower well, where it heats the bitumen that then flows by gravity to the deeper producing well. The OrCrude™ 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 OrCrude™ process with commercially available hydrocracking and gasification technologies, sour crude oil is upgraded to light (39° API) PSC™, 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 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, which we expect will provide us with a significant margin advantage in the long term.



## OUR STRATEGIC ADVANTAGE

Our integrated SAGD and upgrading process addresses three main economic hurdles of SAGD bitumen production: i) the potentially high cost of natural gas; ii) the cost and availability of diluent; and iii) the typically lower realized price of bitumen. Using synthetic gas from the asphaltenes as fuel, we expect to purchase considerably less natural gas. With the upgrading facilities on site, diluent is not required to transport the bitumen to market. By upgrading the bitumen into a highly desirable refinery feedstock or diluent supply, the end product commands the same premium price as light, sweet crude oil.

## LONG LAKE PROJECT

The Long Lake project received regulatory approval in 2003 and was sanctioned in 2004. In 2007, we began injecting steam into the well pairs. We continued to steam the SAGD well pairs and began turning wells over to SAGD production in 2008. In 2009, we improved steam reliability and operability. We also installed electric submersible pumps (ESPs) in a number of our SAGD wells throughout 2009 and 2010. This allows us to improve pressure control in the wells and should ultimately reduce our overall steam-to-oil ratio (SOR). The first several months of steam injection in a well pair largely involve heating the reservoir, followed by a ramp-up of bitumen production to peak rates over 12 to 24 months. Our ramp-up has been slower than initially anticipated but still within industry experience. At the start of production, SORs are high but is 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.

Our share of SAGD bitumen production in 2010 averaged 24,400 bbls/d (15,900 net to us). We are currently producing approximately 27,000 bbls/d of bitumen (17,600 net to us).

We completed construction of the upgrader in 2008 and began commissioning for commercial operations shortly thereafter. Initial production of PSC™ oil from the upgrader began in 2009. As the upgrader ramps up to capacity, we expect periods of downtime as we work through the various stages of commissioning and ramp-up. This periodic downtime is normal following initial facility start-up and consistent with industry experience, especially when dealing with new technologies. We are also progressing projects that will increase the operating independence between our

SAGD facilities and the upgrader while maintaining the benefits of integration. During the bitumen ramp-up period, we have purchased third-party bitumen to assist with upgrader start-up. Production design capacity for Long Lake is approximately 60,000 bbls/d (39,000 net to us at a 65% working interest) of PSC™. We expect to maintain production over the project's life, estimated at 40 years, by periodically drilling additional SAGD well pairs.

In 2010, we processed about 29,200 bbls/d gross of bitumen through the upgrader, producing 19,400 bbls/d gross of PSC™. Combined SAGD, cogeneration and upgrading operating costs are expected to average about \$30/bbl once we reach design capacities, which are substantially lower than coking or other upgrading processes as a result of the reduced energy input costs. We expect ongoing capital costs to average between \$5/bbl and \$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.

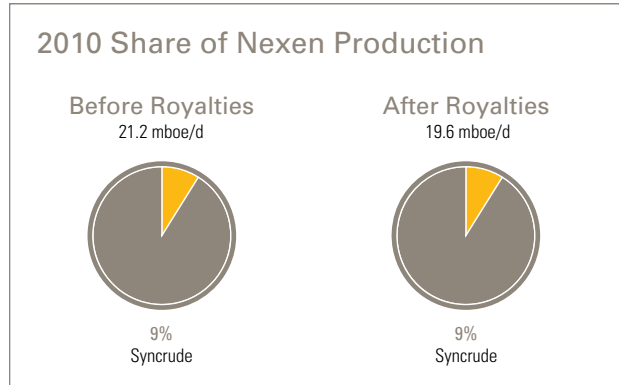
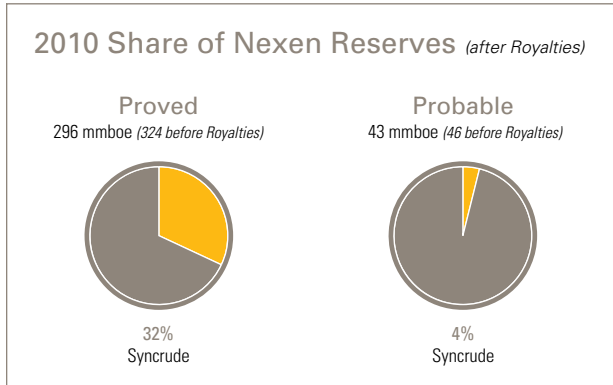
## FUTURE PROJECTS

We have approximately 290,000 net acres of bitumen-prone lands in the Athabasca region. We plan to continue developing our bitumen lands in phases. In 2010, we invested \$30 million on additional drilling, seismic and engineering to develop our leases and advance regulatory applications for future phases. Long Lake is expected to be followed by additional phases with each project leveraging knowledge and experience from previous phases. We currently have regulatory approval for up to 140,000 bbls/d at our second phase of Long Lake, called Kinosis.

Kinosis is expected to be similar in design but will have two smaller SAGD stages feeding the upgrader. The upgrader will be constructed after bitumen production from the first SAGD stage ramps up, provided economics of upgrading are favorable. By keeping the core team in place, and repeating and improving on existing designs and implementation plans, we expect to gain efficiencies in engineering, modular fabrication and on-site construction. We also anticipate enhanced operating efficiencies as we can train and move people easily between the various plants.

## Syncrude

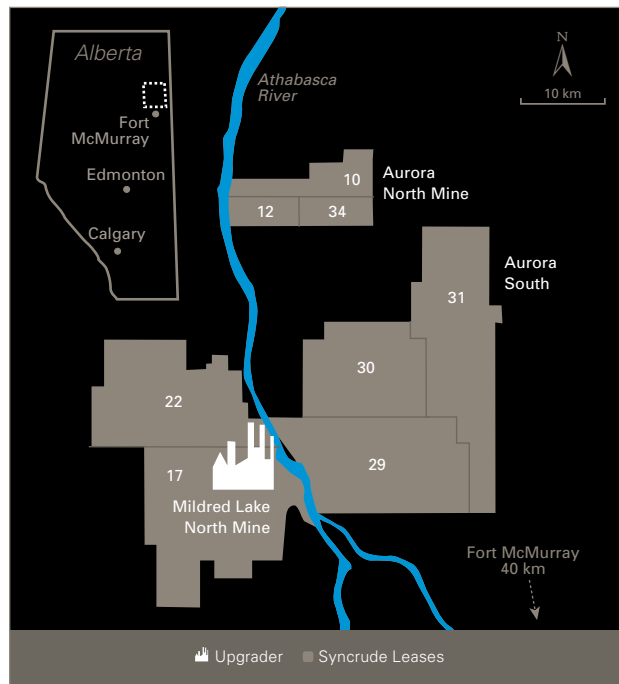
We hold a 7.23% participating interest in the Syncrude joint venture. This joint venture was established in 1975 to mine shallow oil sand deposits using open-pit mining methods, extract the bitumen and upgrade it to a high-quality, light (32° API), sweet, synthetic crude oil. Syncrude's operating strategy 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. These locations are readily accessible by public road. 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. The resulting products are then separated into naphtha, light gas-oil and heavy gas-oil streams. These streams are hydrotreated to remove sulphur and nitrogen impurities to form 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 2010, 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.

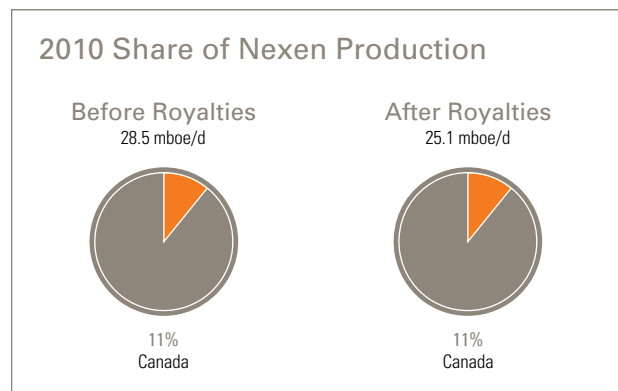
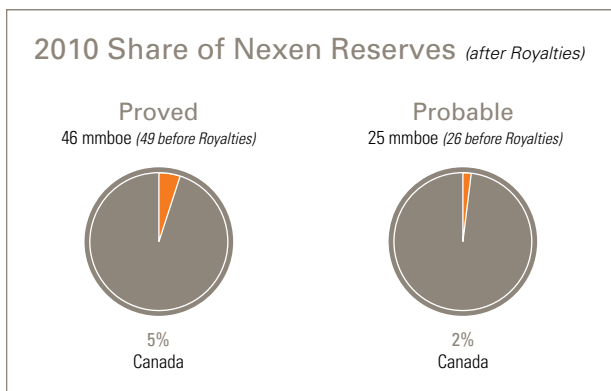
In 1999, the AEUB approved an increase in Syncrude's production capacity to 465,700 bbls/d. At the end of 2001, Syncrude increased its synthetic crude oil capacity to 246,500 bbls/d with the development of the Aurora North Mine, which involved extending mining operations to a new location about 40 km 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. As of January 2002, this royalty was equal to the greater of 1% of gross revenue or 25% of net synthetic-based profit after deducting bitumen related operating expenses and new capital expenditures. In connection with the provincial government's review of Alberta royalty rates in 2007, the Syncrude owners negotiated revised royalty terms at the request of the 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. The \$5 billion royalty deductions previously received by the Syncrude owners will be recaptured by the Alberta government over a 25-year period. In addition, the Province of Alberta and Syncrude reached an agreement to establish new transitional royalty terms. Under the terms of the agreement, until December 31, 2015, 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). 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 announced in October 2007, that became effective January 1, 2009. After January 1, 2016, the rates under the new Alberta royalty framework will apply to the Syncrude project. See Fiscal Terms on page 24.

## UNCONVENTIONAL GAS

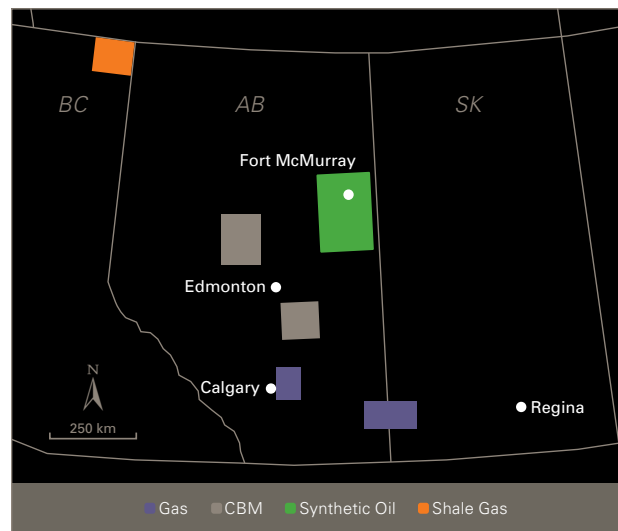
### Canada

- We doubled our prospective shale gas acreage in northeast British Columbia in the Horn River, Cordova and Liard basins in 2010.
- We drilled, fraced and completed our recent eight-well pad in the Horn River Basin at an industry-leading pace during the year.



As part of our growth strategy in unconventional Canadian resource plays, we have accumulated over 300,000 acres of highly 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.

Our shale gas resource will allow us to take advantage of emerging markets such as growing oil sands demand and potential liquid natural gas (LNG) export opportunities. 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. Once our commercial well design is established, we can match the pace of drilling 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 coalbed methane (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. Proved reserves associated with the sold properties were approximately 36 mmboe (30 after royalties).

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.

## SHALE GAS

Approximately 25% of our current Canadian production (excluding Athabasca oil sands) is from our shale gas properties in the Horn River. This basin is a significant shale gas play in northeast British Columbia with high resource density and excellent well productivity. Although historically the United States has been the largest producer of shale gas, new drilling technologies have allowed us to take advantage of vast resource potential in emerging gas plays in Canada.

In 2010, we invested \$476 million progressing development of our shale gas assets at Horn River. We drilled and completed an eight-well pad with an average of 18 fracs per well during the year. These wells were completed at an industry-leading pace of 3.5 fracs per day and we achieved a 100% success rate on our fracs. Substantial cost savings and productivity improvements were realized as we leveraged learnings from prior activities to improve equipment utilization, drill longer wells and initiate more fracs per well. We recently started producing these wells and are experiencing initial production rates of 8 to 15 mmcf/d per well. We also commenced drilling a nine-well pad late in 2010 that is expected to be on stream in late 2011.

Following our success at the June 2010 land sale, we increased our position from 128,000 to over 300,000 acres of highly prospective shale gas lands in northeast British Columbia. This includes additional acreage at Cordova and a new position in the Liard basin. We have a 100% operated interest in all of our shale gas properties.

To date, we have invested in land, infrastructure and wells in the Horn River Basin to progress our shale gas strategy toward development and reserve recognition. We have recognized proved undeveloped reserves relating to our existing area of operations.

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 ten years on the majority of our Horn River lands at Dilly Creek with drilling currently underway to secure the remainder. 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 entered into additional agreements that will allow us to participate in regional infrastructure expansion projects.

## OTHER

Conventional natural gas properties in Alberta and Saskatchewan account for 50% of our current Canadian production (excluding Athabasca oil sands). Canadian production includes minimal volumes from sour gas reservoirs near Calgary. Sour gas is natural gas that contains hydrogen sulphide and requires additional processing. This gas is processed through our operated Balzac plant which we plan to decommission in 2011. Remaining gas production from the Balzac field is expected to be processed by third-party gas plants.

Approximately 25% of our current Canadian production is 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.

## FISCAL TERMS

In Canada, we pay two types of royalties to federal and provincial governments on production from lands where they own the petroleum and natural gas rights. The first type of royalty, Net Profits Interest (NPI), applies to our oil sands projects and our Horn River shale gas project. The second type is a Gross Royalty system whereby we pay royalties ranging from nil to 50% depending upon drilling date, production rate and product sales price.

The NPI royalty rates for oil sands projects range from 1 to 9% of gross revenue for projects that are pre-payout of costs, and 25 to 40% of net profit for projects that are post-payout. These royalty rates vary depending on the Canadian dollar equivalent of WTI. Royalty rates remain at their floor until Cdn\$55/bbl and reach their maximum at Cdn\$120/bbl.

In British Columbia, within a designated area, a 2% royalty on project gross revenue is payable to the provincial government until our Horn River shale gas project reaches payout or 10 years pass, whichever is sooner. After that point, royalties are calculated on project net revenue as defined by the province using progressive rates of 15%, 20% and 35%, with a minimum royalty payable of 5% on project gross revenue.

The Gross Royalty system has an upper royalty rate limit to 50% and lower limit to nil, for conventional oil, depending on production rates and sales price. Most of our conventional Alberta production qualifies for lower rates and we expect royalties on our production to range between 5 and 10%.

In 2009, the Alberta government commissioned a Competitiveness Review, which included a review of the provincial royalty system. As a result of this review, the price sensitivity of the royalty curves for natural gas and conventional oil were reduced along with the maximum royalty rates payable from 50% to 36% for natural gas and from 50% to 40% for conventional oil effective January 1, 2011. In addition, any new wells drilled in Alberta pay a maximum royalty of 5% for the first year of production or 500 mmcf of gas or 50,000 bbls of oil, whichever comes first. New CBM wells receive a longer 5% maximum royalty holiday of 3 years or 750 mmcf of production. The result of this review had a small positive impact for the royalties paid on our CBM and conventional gas properties in Alberta.

In addition to royalties, some provinces impose taxes on production from lands where they do not own the mineral rights. The Saskatchewan government assesses a resource surcharge on gross Saskatchewan resource sales that are subject to Crown royalties, ranging from 1.7 to 3.0%. In Alberta, we are subject to a freehold mineral tax of approximately 4% on production from freehold lands.

Profits earned in Canada from resource properties are subject to federal and provincial income taxes. In 2010, federal taxable income is taxed at 18% and will be taxed at 16.5% in 2011 and 15% in 2012. Provincial income tax rates vary from approximately 10 to 16%.

## ENERGY MARKETING

Our energy marketing group's primary focus is to market proprietary crude oil production from North America, the North Sea and Yemen. We also buy and sell third-party production which provides us with additional market intelligence and opportunities in order to obtain competitive pricing. Our team also leverages regional knowledge, capacity on key North American infrastructure, and solid customer relationships. In addition to physical marketing, we take advantage of quality, time and location spreads to generate returns. We use financial contracts, including futures, forwards, swaps and options for hedging purposes.

In addition to global crude oil marketing activities, we have a North American natural gas and power marketing business. The North American natural gas team's activities are located primarily in western Canada to support our proprietary needs as well as those of other regional producers. The power team is responsible for optimizing and selling power from our Alberta assets including our 50% interest in the Balzac power generation facility; our 50% interest in the Soderghen wind power operation; and surplus power from our cogeneration facility at Long Lake. We also market power to larger commercial, industrial and municipal clients.

During 2010, we concluded the sale of our North American natural gas trading operations, our North Dakota and Montana crude oil lease gathering, pipeline and storage assets, and our European gas and power business.

## CHEMICALS

In 2005, we monetized part of our chemicals business through an initial public offering of the Canexus Income Fund. During 2010, we held a 63.9% interest in our chemicals business.

Our chemicals business manufactures sodium chlorate and chlor-alkali products (chlorine, caustic soda and muriatic acid) in Canada and Brazil. This production is sold in North and South America, with some sodium chlorate distributed in Asia. Our manufacturing system is reliable, low-cost and strategically located to capitalize on competitive electricity costs and transportation infrastructure to minimize production and delivery costs.

In 2010, the technology conversion process (TCP) at the North Vancouver chlor-alkali facility was successfully commissioned. The TCP replaced the diaphragm technology with newer, proven membrane technology that is expected to be more cost-effective and expanded productive capacity by 35%.

In early 2011, we sold our interest in this business for net proceeds of \$458 million. The sale closed in early February 2011 and we will have no involvement in Canexus after such time. The operations have been presented as discontinued operations in our Consolidated Financial Statements.

## RESERVES, PRODUCTION AND RELATED INFORMATION

The following reserves estimates have been prepared in accordance with SEC requirements. In addition to the information below, we refer to the Supplementary Data on page 173 of our 2010 Consolidated Financial Statements for information on our oil and gas producing activities. 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 the last fiscal year.

We have also prepared estimates of reserves and related disclosures in accordance with NI 51-101. This information is contained in the following documents:

- Form 51-101F1 – Statement of Reserves Data and Other Oil and Gas Information
- Form 51-101F2 – Report on Reserves Data by Internal Qualified Reserves Evaluator
- Form 51-101F3 – Report of Management and Directors on Oil and Gas Disclosure

These documents are available on SEDAR at [www.sedar.com](http://www.sedar.com) and are incorporated by reference herein.

### Oil and Gas Reserves

The process of estimating reserves requires complex judgments and decision-making. Reserves are categorized by the confidence that they will be economically recoverable. Probable reserves are less certain to be recovered than proved reserves. Refer to the Basis of Reserves Estimates on page 31 for a description of probable reserves and our process for estimating proved and probable reserves.

At December 31, 2010, we had 987 mmbob of proved reserves (918 after royalties) and 1,133 mmbob of probable reserves (995 after royalties).

The following is a summary of our proved and probable reserves as at December 31, 2010:

	Reserves					
	Before Royalties			After Royalties		
	Synthetic Oil (mmbbl)	Oil (mmbbl)	Gas (bcf)	Synthetic Oil (mmbbl)	Oil (mmbbl)	Gas (bcf)
Developed	249	167	367	229	161	337
Undeveloped	389	100	127	358	94	122
<b>Total Proved</b>	<b>638</b>	<b>267</b>	<b>494</b>	<b>587</b>	<b>255</b>	<b>459</b>
Developed	21	66	147	17	65	133
Undeveloped	907	90	151	788	79	146
<b>Total Probable</b>	<b>928</b>	<b>156</b>	<b>298</b>	<b>805</b>	<b>144</b>	<b>279</b>

## Proved Reserves

In 2010, we added 101 mmboe of proved reserves (107 after royalties), sold 36 mmboe (30 after royalties) associated with our heavy oil properties and produced 89 mmboe (79 after royalties).

The following table provides a summary of the changes in our proved oil and gas reserves before royalties during 2010. Refer to pages 174 and 175 in our Consolidated Financial Statements for proved reserves information on an after-royalty basis.

(mmboe)	Canada						
	Oil Sands			United Kingdom	United States	Other <sup>1</sup>	Total
	Syncrude	Insitu	Other				
December 31, 2009	324	318	81	172	50	66	1,011
Extensions and discoveries	8	3	16	40	–	1	68
Revisions—technical	–	(3)	(3)	30	2	5	31
Revisions—economic	–	–	1	1	(1)	–	1
Acquisitions	–	–	–	1	–	–	1
Divestments	–	–	(36)	–	–	–	(36)
Production	(8)	(4)	(10)	(40)	(10)	(17)	(89)
<b>December 31, 2010</b>	<b>324</b>	<b>314</b>	<b>49</b>	<b>204</b>	<b>41</b>	<b>55</b>	<b>987</b>

<sup>1</sup> Represents reserves in Yemen, Nigeria and Colombia.

Extensions and discoveries of 68 mmboe (66 after royalties) relate primarily to our discoveries at Golden Eagle, Rochelle and Blackbird in the UK, and the recognition of shale gas reserves from our Horn River development program.

Technical revisions of 31 mmboe (27 after royalties) relate primarily to positive production performance at Buzzard and Telford in the United Kingdom, and in Yemen. These were partially offset by a reduction of reserves at Long Lake due to an adjustment in upgrader PSC™ yield and revised geological mapping resulting from this year's core hole delineation program, as well as performance revisions in our Canadian CBM and gas properties.

Positive economic revisions of 1 mmboe (13 after royalties) reflect changes in average oil and gas prices and costs between 2009 and 2010. The increase primarily reflects higher average oil prices offset somewhat by rising costs. Gas prices did not change significantly from 2009 so there were no related economic revisions in our gas properties. The higher after-royalty economic revisions reflect the impact of higher price-sensitive royalties from our oil sands properties at Long Lake and Syncrude as it takes fewer barrels to satisfy our obligations at higher prices.

The divestment of 36 mmboe (30 after royalties) relates to the sale of our Canadian heavy oil properties for which we received \$939 million.

The following provides a summary of the changes in our proved oil and gas reserves before royalties during the past three years. Refer to pages 174 and 175 in our Consolidated Financial Statements for proved reserves information on an after-royalty basis for each of the past three years.

	Canada						Total
	Oil Sands			United Kingdom	United States	Other	
	Syncrude <sup>1</sup>	Insitu	Other				
<i>(mmboe)</i>							
December 31, 2007	324	268	118	207	62	79	1,058
Extensions and discoveries	23	47	28	65	4	10	177
Revisions—technical	–	(7)	3	52	3	27	78
Revisions—economic	–	–	(26)	(6)	(2)	1	(33)
Acquisitions	–	86	–	1	–	–	87
Divestments	–	–	(36)	–	–	–	(36)
Production	(23)	(9)	(38)	(115)	(26)	(62)	(273)
SEC Rule Transition <sup>2</sup>	–	(71)	–	–	–	–	(71)
<b>December 31, 2010</b>	<b>324</b>	<b>314</b>	<b>49</b>	<b>204</b>	<b>41</b>	<b>55</b>	<b>987</b>

<sup>1</sup> We have included Syncrude as oil and gas activity from 2007.

<sup>2</sup> On December 31, 2008, the SEC issued final revised rules relating to reserves definitions and related disclosure requirements. These new rules were effective for year-end 2009 disclosures.

Since 2007, we have added 309 mmboe (350 after royalties), sold 36 mmboe (30 after royalties) and produced 273 mmboe (236 after royalties). Extensions and discoveries of 177 mmboe (169 after royalties) occurred primarily at Long Lake, Syncrude, Buzzard, Golden Eagle and our Canadian shale gas properties. The technical revisions of 78 mmboe (63 after royalties) include 52 mmboe (52 after royalties) of positive revisions in the UK, primarily related to better production performance at Buzzard, and 28 mmboe (13 after royalties) from better than expected production performance at Yemen. Negative technical revisions occurred primarily at Long Lake to reflect lease set-back agreements, revised geological mapping and adjustments to our upgrader yield. Negative economic revisions of

33 mmboe (positive 32 after royalties) are primarily related to changes in prices and costs, primarily in our gas properties in Canada and the US. The positive economic revision after royalties reflects the decrease in royalty obligations for oil sands projects which are sensitive to price. Acquisitions of 87 mmboe (86 after royalties) are from our purchase of additional interests in Long Lake and our Telford property in the UK. Divestments of 36 mmboe (30 after royalties) are related to the sale of our Canadian heavy oil properties. The transition to new SEC rules in 2009 caused a reduction of 71 mmboe (83 after royalties) in our Long Lake oil sands property as reserves are now presented as upgraded synthetic oil barrels rather than bitumen barrels.

## PROVED DEVELOPED AND UNDEVELOPED RESERVES

The following tables provide proved undeveloped reserves (PUDs) before and after royalties at December 31, 2010 and the changes during 2010:

	Canada						Total
	Oil Sands			United Kingdom	United States	Other	
	Syncrude	Insitu	Other				
<i>Before royalties (mmboe)</i>							
December 31, 2009	116	261	3	28	11	39	458
Extensions and discoveries	7	3	7	40	–	1	58
Revisions—technical	–	2	–	11	(1)	–	12
Revisions—economic	–	–	–	1	–	–	1
Conversions	–	–	–	(17)	–	(1)	(18)
Acquisitions	–	–	–	1	–	–	1
Divestments	–	–	(2)	–	–	–	(2)
<b>December 31, 2010</b>	<b>123</b>	<b>266</b>	<b>8</b>	<b>64</b>	<b>10</b>	<b>39</b>	<b>510</b>
PUD % <sup>1</sup>	38%	85%	16%	32%	24%	70%	52%

<sup>1</sup> Determined as a percentage of total proved reserves for that area.

	Canada						Total
	Oil Sands			United Kingdom	United States	Other	
	Syncrude	Insitu	Other				
<i>After royalties (mmboe)</i>							
December 31, 2009	103	236	2	28	10	34	413
Extensions and discoveries	6	3	7	40	–	1	57
Revisions—technical	–	3	–	11	(1)	–	13
Revisions—economic	5	2	–	1	–	–	8
Conversions	–	–	–	(17)	–	(1)	(18)
Acquisitions	–	–	–	1	–	–	1
Divestments	–	–	(2)	–	–	–	(2)
<b>December 31, 2010</b>	<b>114</b>	<b>244</b>	<b>7</b>	<b>64</b>	<b>9</b>	<b>34</b>	<b>472</b>
PUD % <sup>1</sup>	39%	84%	15%	32%	24%	75%	51%

<sup>1</sup> Determined as a percentage of total proved reserves for that area.

In 2010, our PUDs increased by 52 mmboe (59 after royalties). Extensions and discoveries of 58 mmboe (57 after royalties) relate to our discoveries at Golden Eagle, Rochelle and Blackbird in the UK, a 9-well shale gas pad in the Horn River Basin that is currently being drilled, the addition of another year of production capacity at Syncrude which will come from an undeveloped mine and the addition of lands immediately offsetting our developed lands at Long Lake. The higher after-royalty economic revisions reflect the impact of higher price-sensitive royalties from our oil sands properties at Long Lake and Syncrude as it takes fewer barrels to satisfy our obligations at higher prices. We converted 18 mmboe (18 after royalties) to proved developed, primarily from Buzzard where we converted all of the proved undeveloped reserves associated with the fourth platform, and also from ongoing drilling at Ettrick.

At Syncrude, PUDs of 123 mmboe (114 after royalties) relate to the Aurora South mine that will be required to provide bitumen feedstock to the upgrading facility during its expected life. The mine is part of 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 to access the reserves has not yet been installed. We are proceeding with planning for the development of the mine and expect to initiate mine construction in 2016. The PUDs are expected to be converted in eight to ten years when the project is sufficiently developed.

At Long Lake, 266 mmboe (244 after royalties) of PUDs relate to ongoing drilling of the lease to offset declines from the initial SAGD wells. They are expected to be converted over the next 25 years as we drill additional wells to maintain upgrader feedstock. These wells were part of the initial field development plan and were included in the project investment decision.

In the UK, we have 64 mmboe (64 after royalties) of PUDs. Discoveries at Golden Eagle, Rochelle and Blackbird account for 40 mmboe (40 after royalties). The remainder is comprised of 16 mmboe (16 after royalties) at Buzzard for future development wells and 8 mmboe (8 after royalties) at Telford for the tie-in of our successful TAC well and the replacement of a water injection flowline. All of these PUDs are expected to be converted within the next five years.

In our other international operations, 39 mmboe (34 after royalties) of PUDs relate primarily to offshore West Africa. They will be converted in 2012 when construction and commissioning of the FPSO and subsea facilities is completed.

In 2010, we spent \$782 million on converting PUDs to proved developed reserves and on those to be converted in future years.

During the year, we converted 18 mmboe (18 after royalties) or about 4% of our PUDs that existed at the end of last year. The conversion rate in 2010 is low because about 90% of the PUDs relate to our Long Lake, Syncrude and Usan projects where conversions take place over 25 years as the wells are needed (Long Lake) or where they are tied to the completion of long cycle-time projects (Syncrude and Usan). Excluding these three projects, we converted 44% of our 2009 PUDs to developed in 2010 and 77% 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 2010 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 five 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, 2010:

	Before Royalties			After Royalties		
	Synthetic Oil (mmbbl)	Oil (mmbbl)	Gas (bcf)	Synthetic Oil (mmbbl)	Oil (mmbbl)	Gas (bcf)
Canada	249	–	246	229	–	231
United Kingdom	–	138	12	–	138	12
United States	–	13	109	–	12	94
Other Countries	–	16	–	–	11	–
<b>Developed</b>	<b>249</b>	<b>167</b>	<b>367</b>	<b>229</b>	<b>161</b>	<b>337</b>
Canada	389	–	47	358	–	44
United Kingdom	–	55	55	–	55	55
United States	–	6	25	–	5	23
Other Countries	–	39	–	–	34	–
<b>Undeveloped</b>	<b>389</b>	<b>100</b>	<b>127</b>	<b>358</b>	<b>94</b>	<b>122</b>
<b>Total Proved</b>	<b>638</b>	<b>267</b>	<b>494</b>	<b>587</b>	<b>255</b>	<b>459</b>

## 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, 2010, we had 1,133 mmboe (995 after royalties) of probable oil and gas reserves. During the year, we added 25 mmboe (40 after royalties), converted 80 mmboe (78 after royalties) and sold 29 mmboe (24 after royalties), resulting in a reduction of 84 mmboe (62 after royalties) in our probable reserves.

The following provides a summary of the changes in our probable oil and gas reserves before and after royalties during 2010:

	Canada						Total
	Oil Sands			United Kingdom	United States	Other	
	Syncrude	Insitu <sup>1</sup>	Other				
<i>Before royalties (mmboe)</i>							
December 31, 2009	46	888	41	169	24	49	1,217
Extensions and discoveries	8	–	17	6	–	–	31
Revisions—technical	–	(2)	(3)	–	–	(4)	(9)
Revisions—economic	–	(1)	–	1	(1)	–	(1)
Conversions	(8)	(3)	–	(62)	(3)	(4)	(80)
Acquisitions	–	–	–	4	–	–	4
Divestments	–	–	(29)	–	–	–	(29)
<b>December 31, 2010</b>	<b>46</b>	<b>882</b>	<b>26</b>	<b>118</b>	<b>20</b>	<b>41</b>	<b>1,133</b>

<sup>1</sup> Insitu oil sands reflect our share of the probable reserves at Long Lake and Kinosis.

	Canada						Total
	Oil Sands			United Kingdom	United States	Other	
	Syncrude	Insitu <sup>1</sup>	Other				
<i>After royalties (mmboe)</i>							
December 31, 2009	41	754	35	169	20	38	1,057
Extensions and discoveries	7	–	17	6	–	–	30
Revisions—technical	–	(2)	(3)	–	–	(3)	(8)
Revisions—economic	2	13	–	1	–	(2)	14
Conversions	(7)	(3)	–	(62)	(3)	(3)	(78)
Acquisitions	–	–	–	4	–	–	4
Divestments	–	–	(24)	–	–	–	(24)
<b>December 31, 2010</b>	<b>43</b>	<b>762</b>	<b>25</b>	<b>118</b>	<b>17</b>	<b>30</b>	<b>995</b>

<sup>1</sup> Insitu oil sands reflect our share of the probable reserves for Long Lake and Kinosis.

Extensions and discoveries of 31 mmboe (30 after royalties) relate primarily to our Horn River Basin 18-well development pad expected to be drilled in 2011 and exploration successes at Rochelle and Blackbird in the UK. Negative technical revisions of 9 mmboe (8 after royalties) relate primarily to performance revisions in our Canadian conventional gas properties, and geological revisions at Long Lake and our Usan development in Nigeria. The higher after-royalty basis economic revision reflects the impact of price-sensitive royalties from our oil sands properties at

Long Lake and Kinosis as it takes fewer barrels at higher prices to satisfy our obligation. Conversions reflect probable reserves converted to proved as a result of increased confidence in producing the reserves based on advancement of development plans, production performance and drilling results. The divestments represent the probable reserves associated with the heavy oil properties we sold. The acquisition reflects the additional working interest acquired from our partner at Telford.

## 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, 2010:

	Before Royalties			After Royalties		
	Synthetic Oil	Oil	Gas	Synthetic Oil	Oil	Gas
	(mmbbl)	(mmbbl)	(bcf)	(mmbbl)	(mmbbl)	(bcf)
Canada	21	–	67	17	–	62
United Kingdom	–	58	16	–	58	16
United States	–	5	64	–	5	55
Other Countries	–	3	–	–	2	–
<b>Developed</b>	<b>21</b>	<b>66</b>	<b>147</b>	<b>17</b>	<b>65</b>	<b>133</b>
Canada	907	–	92	788	–	89
United Kingdom	–	50	44	–	50	44
United States	–	2	15	–	1	13
Other Countries	–	38	–	–	28	–
<b>Undeveloped</b>	<b>907</b>	<b>90</b>	<b>151</b>	<b>788</b>	<b>79</b>	<b>146</b>
<b>Total Probable</b>	<b>928</b>	<b>156</b>	<b>298</b>	<b>805</b>	<b>144</b>	<b>279</b>

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.

Approximately 90% of our probable reserves before royalties (90% after royalties) are undeveloped. This primarily reflects the incremental synthetic oil reserves related to future drilling required to keep the upgrader full at Long Lake, the reserves related to the expected development of Kinosis, and the extension of the plant life and expected higher future yields at Syncrude. The remaining undeveloped reserves principally relate to the expected 18-well development pad in the Horn River Basin, undeveloped discoveries at Rochelle and Blackbird in the UK, and Usan and Owowo, offshore West Africa.

## 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, 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.

Reserve estimates are categorized by the confidence that they will be economically recoverable. Proved reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating conditions and government regulations. 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.

Our reserves estimates 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 200 individuals in multifunctional teams with relevant experience in reserves evaluation, engineering and geoscience, and over 150 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.

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 28 years of experience, he has an in-depth knowledge of reserves estimation techniques and professional guidelines, and SEC and Canadian reserves regulations and related reporting requirements. His primary duty includes assessing whether the reserves estimates and related disclosures have been prepared in accordance with applicable regulatory requirements.

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.

We have at least 80% of our oil and gas reserves either evaluated or audited annually by independent qualified reserves consultants using SEC 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.

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 reserves consultants, independent of management, 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 reserves consultants, their independence.

In the event of a proposed change to the areas of responsibility of either an independent 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.

The following provides an overview of the nature and scope of the independent evaluations and audits that we have performed. 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 auditor reviews our work and estimate in preparing their estimate, whereas an evaluator uses the reservoir data to prepare their own estimate.

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 SEC 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 the SEC and Financial Accounting Standards Board requirements.

For our reserves estimates prepared in accordance with SEC requirements, we engaged three independent reserves consultants to evaluate or audit our properties:

- We engaged DeGolyer and MacNaughton (D&M) to evaluate 97% of our proved and 96% of our proved plus probable reserves in the United Kingdom, Nigeria, Yemen 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 Canadian conventional, CBM and insitu 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 93% of our proved and 95% 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.

For each opinion, a Report of Third Party 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](http://www.sedar.com).

## Special Note to Canadian Investors

Nexen has received an exemption from the securities regulatory authorities in the various provinces of Canada, that permits us to prepare our reserves estimates and disclosures in accordance with SEC requirements in this AIF. As discussed on page 25, reserves estimates and disclosures prepared in accordance with NI 51-101 have been filed on Form 51-101F1 at the same time as this AIF on SEDAR and are incorporated by reference herein.

As a result of this exemption, Nexen's disclosures may differ from other Canadian companies and 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 Canadian Oil and Gas Evaluation (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 noted below, 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 to be aggregated, whereas NI 51-101 requires issuers to do such aggregation.

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.

Nexen has also received an exemption from NI 51-101 that permits us to forego the requirement to have our reserves and related future net revenue evaluated, audited or reviewed by an independent qualified reserves evaluator or auditor. Accordingly, our future net revenue and reserves estimates are based on internal evaluations. 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 reserves estimates is not materially less than would be generated by an independent reserves evaluator.

## Net Sales by Product from Oil and Gas Operations <sup>1</sup>

(Cdn\$ millions)	2010	2009	2008
Conventional Crude Oil and Natural Gas Liquids (NGLs)	4,121	3,605	5,534
Synthetic Crude Oil	978	480	691
Natural Gas	411	316	652
<b>Total</b>	<b>5,510</b>	<b>4,401</b>	<b>6,877</b>

<sup>1</sup> Includes results of discontinued operations (see Note 20 of our Consolidated Financial Statements).

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%.

## Sales Prices and Production Costs

	Average Sales Price <sup>1</sup>			Average Production Cost <sup>1</sup>		
	2010	2009	2008	2010	2009	2008
<b>Crude Oil and NGLs</b> (Cdn\$/bbl)						
Oil Sands—Syncrude	81.23	70.96	105.47	39.78	39.09	42.04
Oil Sands—Insitu	77.07	–	–	105.17	–	–
Canada—Other	61.39	53.04	74.51	20.97	20.82	22.16
United Kingdom	79.02	67.70	96.23	8.24	6.87	6.75
United States	76.73	65.01	104.94	10.76	14.10	13.48
Yemen	81.86	68.49	99.87	18.69	18.34	15.88
Other Countries	76.83	59.05	98.98	7.52	6.53	4.91
<b>Natural Gas</b> (Cdn\$/mcf)						
Canada	3.94	3.78	7.73	1.93	1.92	2.09
United Kingdom	5.28	3.95	6.78	1.38	1.15	1.12
United States	4.97	4.67	10.07	1.79	2.35	2.25
<b>Corporate Average</b> (Cdn\$/boe)	<b>70.11</b>	<b>60.02</b>	<b>89.78</b>	<b>17.62</b>	<b>13.33</b>	<b>13.18</b>

<sup>1</sup> Sales prices and unit production costs are calculated using our working interest production after royalties.

## Oil and Gas Acreage

(thousands of acres)	Developed		Undeveloped <sup>1</sup>		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil Sands—Insitu	14	9	675	281	689	290
Oil Sands—Syncrude	68	5	180	13	248	18
Canada—Other	624	471	1,146	774	1,770	1,245
United Kingdom	219	104	1,435	985	1,654	1,089
United States	205	108	1,201	591	1,406	699
Yemen <sup>2</sup>	47	26	777	649	824	675
Colombia <sup>3</sup>	2	–	676	591	678	591
Nigeria <sup>2,4</sup>	–	–	678	131	678	131
Norway	–	–	627	301	627	301
<b>Total<sup>5</sup></b>	<b>1,179</b>	<b>723</b>	<b>7,395</b>	<b>4,316</b>	<b>8,574</b>	<b>5,039</b>

<sup>1</sup> 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.

<sup>2</sup> The acreage is covered by production-sharing contracts.

<sup>3</sup> The acreage is covered by an association contract.

<sup>4</sup> The acreage is covered by joint venture agreements.

<sup>5</sup> Approximately 29% 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

(number of wells)	Oil		Gas		Total	
	Gross <sup>1</sup>	Net <sup>2</sup>	Gross <sup>1</sup>	Net <sup>2</sup>	Gross <sup>1</sup>	Net <sup>2</sup>
Canada	107	63	2,784	2,500	2,891	2,563
United Kingdom	64	31	–	–	64	31
United States	79	45	71	48	150	93
Yemen	472	274	–	–	472	274
Colombia	110	11	–	–	110	11
<b>Total</b>	<b>832</b>	<b>424</b>	<b>2,855</b>	<b>2,548</b>	<b>3,687</b>	<b>2,972</b>

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

(number of net wells)	2010						
	Net Exploratory			Net Development			Total
	Productive	Dry Holes	Total	Productive	Dry Holes	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
<b>Total</b>	<b>11.5</b>	<b>2.0</b>	<b>13.5</b>	<b>40.2</b>	<b>0.9</b>	<b>41.1</b>	<b>54.6</b>

(number of net wells)	2009						
	Net Exploratory			Net Development			Total
	Productive	Dry Holes	Total	Productive	Dry Holes	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
<b>Total</b>	<b>12.1</b>	<b>1.5</b>	<b>13.6</b>	<b>77.5</b>	<b>0.8</b>	<b>78.3</b>	<b>91.9</b>

(number of net wells)	2008						
	Net Exploratory			Net Development			Total
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
Canada	9.2	–	9.2	216.4	–	216.4	225.6
United Kingdom	2.5	2.0	4.5	3.3	–	3.3	7.8
United States	0.5	1.0	1.5	1.3	–	1.3	2.8
Other Countries	–	1.0	1.0	19.0	–	19.0	20.0
<b>Total</b>	<b>12.2</b>	<b>4.0</b>	<b>16.2</b>	<b>240.0</b>	<b>–</b>	<b>240.0</b>	<b>256.2</b>

## Wells in Progress

At December 31, 2010, we were drilling one well in the United Kingdom (0.4 net), 2 wells in Canada (1.3 net) and one well in Yemen (0.5 net). There were no wells drilling in the United States, Colombia, Nigeria or Norway at December 31, 2010.

## 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.

## 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 are currently assessing the cost of compliance associated with these regulations, however we do not anticipate any difficulty meeting them. We believe that the rigorous health, safety and environmental processes that we apply to our existing offshore operating activities will 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 are expected to result in significant delays in the permitting process, which could add to costs and longer cycle times for our Gulf of Mexico exploration and development drilling activities.

The United States Government remains at an impasse as to what extent the oil and gas industry should be held responsible for future oil spills. The 111th Congress adjourned at the end of 2010 with no oil spill legislation passing into law. We anticipate that the 112th Congress will review requirements of financial responsibility and third-party liability caps and we expect some legislation to pass in these areas.

## 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 discharged 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 regulation is becoming more complex and increasingly stringent. To reduce our risk of non-compliance with these laws, we apply industry standards, codes and best practices that meet or exceed our legal obligations. We conduct activities in countries where environmental regulatory frameworks are in various stages of development. Where regulations do not exist, or where we consider them to be insufficiently developed, we observe Canadian standards where applicable, as well as 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 and comprise part of our formal integrity and ethics reporting processes. Nexen's overall HSE&SR program is guided by our corporate HSE&SR management system that incorporates the Responsible Care 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 our sustainability report available at [www.nexeninc.com](http://www.nexeninc.com). For more information on Responsible Care, please refer to our sustainability report and [www.ccpa.ca](http://www.ccpa.ca).

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 and land, 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.

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 four producing assets in the UK sector of the North Sea and in our operations in Canada (located in the provinces of Alberta, Saskatchewan and British Columbia). The Canadian federal government has yet to pass climate change legislation. In 2010, the Canadian and US governments introduced new fuel efficiency standards for the light duty vehicle fleet and the Canadian Federal government has reached agreement with the coal-fired electricity sector in respect of the treatment of the existing coal-fired generation. Canada has previously announced their intent to mirror US legislation in this area but recently indicated they did not have to wait if their best interests were served by unilateral action. In the US, there has been no progress on comprehensive climate/energy legislation and President Obama has indicated it is unlikely his administration will pursue such legislation before the next presidential election in 2012.

Any required reductions in the greenhouse gases (GHGs) emitted from our operations (without an allowed offset compliance mechanism) could result in increases to our capital or operating expense, or reduced operating rates, especially at the Long Lake project, which could have an adverse effect on our results of operations and financial condition. As a “new facility”, Long Lake will have three years to establish an emissions baseline before having a reduction obligation assigned. In 2010, our Canadian operations, including Syncrude, accounted for 27% of our production before royalties.

Alberta became the first jurisdiction in Canada to enact and implement binding economy-wide emission reductions (a one-time from base, 12% reduction in carbon intensity vs. a 2005 baseline) on facilities annually emitting more than 100 kilo-tonnes of CO<sub>2</sub> equivalent. Facilities unable to achieve internal reductions have an unlimited ability to pay into a technology fund at the rate of \$15 per tonne of CO<sub>2</sub> equivalent. This amount must be paid annually until such time as internal reduction is achieved unless other approved offsets are acquired from projects in Alberta.

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 is 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 a carbon tax to all hydrocarbon fuels sold in the province. The tax started at \$10/tonne of CO<sub>2</sub> in 2008 and will increase \$5 per year; it will reach \$30 per tonne in 2012.

It remains to be seen if the federal and provincial governments will harmonize their compliance regimes in Canada.

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 CO<sub>2</sub> 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 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 impact of EPA activity in the area of GHG regulation is expected to be minimal on our operations in the Gulf of Mexico.

Conference of Parties 16 in Cancun failed to achieve any meaningful progress on a post-2012 international agreement to reduce global GHGs. Progress was made on some administrative matters, but important details remain to be negotiated in Durban, South Africa in December 2011. There have been no changes to pledges made by Canada (or other countries where we operate) under the Copenhagen Accord. The Cancun Agreement affirms the goal of limiting global temperature increases to less than 2°C and states that parties consider limiting any increase to no more than 1.5°C.

The Kyoto Protocol does not expire, but the first commitment period expires at the end of 2012. In the absence of progress on a second commitment period the current obligations remain in place. The US did not ratify the Kyoto Protocol and as such has no commitment and Canada has indicated they will not make their target by 2012. In the absence of a second commitment period it is unclear what implications there are for Canadian non-compliance.

The Canadian Council of Ministers of the Environment (the CCME is comprised of the federal and provincial ministers) decided in 2010 to pursue regulation of air pollutants and has established a work plan for 2011 with the expressed

intent of proclaiming regulations in 2012. While we could face technical challenges in meeting minimum emission standards for certain pollutants, we are unable at this time to project the cost of compliance and impact on our operations, but believe them to be immaterial.

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 tools in our investment decision-making process and developing water management systems to enhance water tracking and reporting. Our water data management project, which starts in 2011, will provide us with information we can use to improve water efficiency.

## LAND AND BIODIVERSITY

Our land use practices are based upon principles of minimal disturbance and a commitment to return land to its 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 impact and in how we cooperate with local communities, stakeholders, regulators and other industries to reduce the cumulative effect of our projects throughout their life-cycle.

For many stakeholders, a company's ability to meet environmental expectations is a significant criteria 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 superior 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](http://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. We have prioritized five core areas for the Company's community investment dollars: Education; Employee Matching; Arts and Culture; Community Development; and Aboriginal Partnerships. Details regarding Nexen's community investment initiatives are available in our sustainability report.

### Environmental Provisions and Expenditures

Meeting the challenges of climate change and 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 result in unprofitable or unfavourable operating conditions. During 2010, 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, 2010, \$1,064 million (\$2,552 million, undiscounted, adjusted for inflation) has been provided in our Consolidated Financial Statements for asset retirement obligations.

### EMPLOYEES

We had 3,925 employees on December 31, 2010.

### RISK FACTORS

Our operations are exposed to various risks, some of which are common to others 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 1 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. Extended periods of lower commodity prices may reduce our level of spending for oil and gas exploration and development, and materially adversely affect our results of operations. Lower 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 sensitive to numerous worldwide factors, many of which are beyond our control. These factors include, but are not limited to:

- global 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;
- 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.

## Increased environmental regulation could increase our operating costs and affect profitability.

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. 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; and
- the issuance of permits and other regulatory approvals in connection with the construction of roads, pipelines and other regional transportation infrastructure.

These laws and regulations may impose significant liabilities on a failure to comply with their requirements. Significant changes in the environmental laws and regulations governing our current operations, including many of the proposed initiatives to regulate greenhouse gas emissions, may have an adverse effect on the oil and gas industry, including our company. The cost of meeting new environmental and climate change regulations may have an adverse effect on the viability of future projects, our results of operations, cash flows and financial condition.

## Negative public perception of oil sands development may harm our corporate reputation.

Development of the Athabasca oil sands has figured prominently in recent political, media and activist commentary on the subject of climate change, greenhouse gas emissions, water usage and environmental damage. Concerns over heightened greenhouse gas emissions and water and land use practices in oil sands developments may

directly or indirectly harm the profitability of our current oil sands projects and the viability of future oil sands projects in a number of ways, including:

- creating significant regulatory uncertainty that challenges economic modeling of future projects and potentially delays sanctioning;
- motivating extraordinary environmental and emissions regulation of those projects by governmental authorities that could result in changes to facility design and operating requirements, thereby potentially increasing the cost of construction, operation and abandonment; and
- compelling legislation or policy that limits 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 other jurisdictions throughout the world.

## 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 in 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\$450 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 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.

The 2010 explosion and sinking of the deep-water Horizon rig in the Gulf of Mexico and the resulting oil spill have resulted in increased scrutiny of deep-water operations by governments, environmental groups, investors and the general public, not only in the United States but globally. It is anticipated this will result in increased regulation of deep-water operations, increased cost of compliance with applicable laws and greater difficulty in permitting deep-water operations. There is also a risk 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 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 impact on our credit rating, our ability to raise capital or the cost of such capital.

## 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 operate a sour gas processing facility that is located in close proximity to populated areas and processes materials of potential harm to the local population.

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.

## Unconventional gas resource plays carry additional risks and uncertainties.

Part of Nexen's growth strategy is to invest in unconventional gas resource plays, such as shale gas and CBM. Exploitation techniques and practices for these resources are generally in the early stages of development and it is difficult to determine whether or not these resource plays will prove commercially viable, to what degree or when.

Shale gas is an unconventional gas produced from reservoirs composed of organic rich shales. The gas is stored in pore spaces, fractures or adsorbed into organic matter. Some of the uncertainties associated with development of shale gas resources are as follows:

- shale gas wells typically have higher initial production decline rates than conventional gas wells, although this varies by area;
- regulatory approval is required to drill more than one well per section, resulting in uncertainty in the timing of drilling programs and land development;
- 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;
- lack of access to regional infrastructure for the sale of production; and
- significant capital expenditures are required before establishing commerciality of a particular play.

CBM is commonly referred to as an unconventional form of natural gas because it is primarily stored through adsorption by the coal itself rather than in the pore space of the rock like most conventional gas. The gas is released in response to a drop in pressure in the coal seam. Some of the uncertainties associated with development of CBM resources are as follows:

- if the coalbed is water-saturated, such as the Mannville coals in the Fort Assiniboine region of Alberta, water generally needs to be extracted to reduce the pressure and allow gas production to occur. A significant period of time may be required to de-water these wet coals and

determine if commercial production is feasible. We may also have to invest significant capital in these assets before they achieve commercial rates of production, if ever;

- some coalbeds may not have sufficient natural permeability in the coalbed to recover the gas in place and can therefore require more extensive, and expensive, completion technologies, which can increase the cost of drilling and production or which may not be successful;
- the public may react negatively to certain water disposal practices related to water-saturated CBM projects, even though these water disposal practices are regulated to ensure public safety and water conservation. Negative public perception around water-saturated CBM production could impede our access to the resource;
- CBM wells typically have lower producing rates and reserves per well than conventional gas wells, although this varies by area; and
- regulatory approval is required to drill more than one well per section. 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. As required by SEC rules, our reserves represent the quantities that we expect to economically recover using existing prices and costs held constant. Reserves can increase or decrease under different price and cost scenarios.

### 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.

### Our oil sands projects face additional risks compared to conventional oil and gas production.

Our Long Lake oil sands development is a fully integrated production, upgrading and cogeneration facility. We are using SAGD technology to recover bitumen from oil sands. The bitumen is partially upgraded using our proprietary OrCrude™ process, followed by conventional hydrocracking to produce sweet, light, PSC™ oil. The OrCrude™ process also yields liquid asphaltene that are gasified into synthetic gas. This gas is used as fuel for the SAGD process and a source of hydrogen in the upgrading process and to generate electricity through a cogeneration facility.

We have a 65% working interest in this project. Given the initial investment and operating costs to produce and upgrade bitumen, the payout period for the project is longer and the economic return is lower than a conventional light oil project with an equal volume of reserves.

Risks associated with our Long Lake project include the following:

## APPLICATION OF A RELATIVELY NEW SAGD BITUMEN RECOVERY PROCESS

SAGD has been used in western Canada to increase recoveries from conventional heavy oil reservoirs for over a decade; however, application of SAGD to the insitu recovery of bitumen from oil sands is relatively new. Some of the SAGD oil sands applications to date have been pilot projects, although commercial SAGD projects have been in operation for several years. None, however, incorporate the advanced integration and technology associated with a combined SAGD and upgrader operation.

Our estimates for performance and recoverable volumes for the Long Lake project are based primarily on our three well-pair SAGD pilot, the initial performance of our first commercial well phase and industry performance from SAGD operations in similar reservoirs in the McMurray formation in the Athabasca oil sands. Using this data, our development assumptions included average well-pair productivity of 900 bbls/d of bitumen and a long-term steam-to-oil ratio within a plant capacity of 3.3. While some of our wells have achieved these levels to date, 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 integration of our facilities, we might have to drill additional wells to maintain optimal production levels, construct additional steam generating capacity, reconfigure or construct additional facilities, purchase natural gas for additional steam generation and/or make short-term bitumen purchases. These could have an adverse impact on the future activities and economic return of the Long Lake project.

## APPLICATION OF A NEW BITUMEN UPGRADING PROCESS

The proprietary OrCrude™ process we are using 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 PSC™, reflecting its quality differential;
- the market price for bitumen fluctuates more than the market price for PSC™ ; 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 syngas from the upgrading process.

These factors could have a significant adverse impact on the future activities and economic returns of the Long Lake project.

If any of these factors arise, our operating costs would increase and 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

The combination of a SAGD facility with the new OrCrude™ upgrading facility 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 integration of the facilities creates conditions for interdependent interruptions and limitations to operations impacting ramp-up of the facilities. This requires a number of reconfigurations and modifications during the initial stages of operation to achieve 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 we have experienced to date or 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

The success of the Long Lake project and our investment depends highly on the proprietary technology of OPTI and proprietary technology of third parties that has been, or is required to be, licenced for the project. OPTI 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 OPTI's proprietary technology and the proprietary technology of third parties. OPTI 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 OPTI 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 OPTI. Others may develop technologies that are similar or superior to: i) the technology of OPTI or third parties; or ii) the design around the patents owned by OPTI and/or third parties.

#### OPERATIONAL HAZARDS

The operation of the project is subject to the customary hazards of recovering, transporting and processing hydrocarbons, such as fires, explosions, gas leaks, migration of harmful substances, blowouts and oil spills. A casualty occurrence might result in the loss of equipment or life, as well as injury or property damage. We may not carry insurance with respect to all potential casualty occurrences and disruptions, and our insurance may not sufficiently cover casualty occurrences or disruptions that occur. The Long Lake project could be interrupted by natural disasters or other events beyond our control. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on the Long Lake project and on our business, financial condition and results of operations.

Recovering bitumen from oil sands and upgrading it into synthetic crude oil and other products involve particular risks

and uncertainties. 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.

The Long Lake project is designed to process large volumes of hydrocarbons at high-pressure and temperatures and also handles large volumes of high-pressure steam. Equipment failures could result in damage to the project's 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 produces carbon dioxide emissions. Risk factors relating to environmental regulation are provided separately in this document.

#### 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 bitumen 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 bitumen and shale gas developments.

### 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;
- central processing facilities, oil pipelines and an export terminal at our Yemen operations;
- our Long Lake synthetic crude oil 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.

### 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;
- 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.

### 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, communications and oil field equipment) are vulnerable to these types of extreme weather conditions and may suffer extensive 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 periods of good weather 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.

## 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 and 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 may be affected by changes in government rules and 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 land tenure, drilling, production practices, environmental protection (as discussed above), marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment that are subject to change from time to time. Current legislation is generally a matter of public record and we cannot predict what additional legislation or amendments may be proposed that will affect our operations or when any such proposals, if enacted, might become effective. Changes in government laws and regulations could adversely affect our results of operations and financial condition.

## Our energy marketing operations expose us to the risk of trading losses and liquidity constraints.

Our 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 additional 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.

## 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 where we operate. 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.

## Our debt and other financial commitments may limit our financial and operating flexibility.

As of December 31, 2010 our long-term debt was approximately \$5.2 billion. We also have commitments under capital leases, operating 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.

## A downgrade in our credit rating could increase our cost of capital and limit access to capital.

Rating agencies regularly evaluate the company and our subsidiaries, and their ratings of our long-term and short-term debt are based on a number of factors. This includes our financial strength as well as 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 also could have a significant impact on certain trading revenues, particularly in those businesses where counterparty creditworthiness is critical. It could trigger collateralization requirements related to physical and financial derivative liabilities with certain marketing counterparties and 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 contract and is usually a fixed incremental amount and/or the market value of the exposure.

## 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, 2010, 525,706,403 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.

### 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 (a Flip-In Event), 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 must be reapproved by shareholders on or before our annual general meeting in 2011 to remain effective past that date. A copy of the Plan is available on our website at [www.nexeninc.com](http://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, 2010. 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.

	<b>Standard &amp; Poor's Rating Service (S&amp;P)</b>	<b>Moody's Investors Services (Moody's)</b>	<b>DBRS Limited (DBRS)</b>
Senior Unsecured/Long-Term Rating	BBB-	Baa3 (under review)	BBB
Outlook	Stable	Stable	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 early December 2010, Moody's placed our rating under review, primarily as a result of the delayed ramp up of Long Lake and higher absolute amounts of debt before considering our cash on hand. Discussions with Moody's are ongoing and the outcome is indeterminable at this time.

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. 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 Share

<i>(Cdn\$/share)</i>	<b>First Quarter</b>	<b>Second Quarter</b>	<b>Third Quarter</b>	<b>Fourth Quarter</b>
2010	0.050	0.050	0.050	0.050
2009	0.050	0.050	0.050	0.050
2008	0.025	0.050	0.050	0.050

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 2010 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:

	<b>Toronto Stock Exchange</b>				<b>New York Stock Exchange</b>			
	<i>Cdn\$</i>				<i>US\$</i>			
<b>2010</b>	<b>High</b>	<b>Low</b>	<b>Close</b>	<b>Volume</b>	<b>High</b>	<b>Low</b>	<b>Close</b>	<b>Volume</b>
January	25.91	22.38	23.41	29,143,776	24.93	21.06	21.94	48,404,421
February	24.57	22.69	23.75	35,115,190	23.25	21.31	22.50	48,939,602
March	25.34	23.45	25.13	31,832,701	24.98	22.61	24.71	31,293,552
April	26.91	24.26	24.70	39,503,585	26.92	23.96	24.28	41,802,292
May	24.89	21.58	23.50	41,360,427	24.60	20.00	21.81	61,794,873
June	23.60	20.92	20.94	33,436,024	22.77	19.66	19.67	36,653,095
July	22.33	20.34	21.35	31,422,187	21.54	19.19	20.70	33,944,207
August	21.89	18.33	19.75	42,714,266	21.45	17.20	18.51	29,970,477
September	21.03	19.31	20.70	37,048,759	20.48	18.69	20.10	38,727,967
October	22.74	20.57	21.70	37,331,540	22.39	20.12	21.29	48,129,155
November	22.71	20.68	21.47	35,243,469	22.56	20.42	20.92	49,103,219
December	23.00	21.11	22.80	28,466,298	23.01	20.73	22.90	39,177,560

## Subordinated Notes

Our 7.35% subordinated notes due 2043 (7.35% Notes) are listed and traded on the TSX under the trading symbol “NXY.PRU” 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:

2010	Toronto Stock Exchange <i>Cdn\$</i>				New York Stock Exchange <i>US\$</i>			
	High	Low	Close	Volume	High	Low	Close	Volume
January	24.46	24.19	24.25	113,146	25.07	23.60	24.23	324,085
February	23.99	23.94	23.97	29,946	24.60	23.57	23.95	364,104
March	24.85	24.77	24.83	26,103	25.08	24.38	24.82	231,756
April	25.01	24.93	24.97	76,910	25.08	24.50	24.85	158,619
May	24.65	24.51	24.60	29,850	24.93	23.76	24.54	136,145
June	24.76	24.66	24.69	22,164	24.90	24.26	24.63	436,078
July	24.95	24.91	24.94	13,414	25.23	24.55	24.89	447,731
August	25.03	24.96	24.98	13,982	25.18	24.80	24.99	207,052
September	25.29	25.20	25.24	8,655	25.50	25.00	25.21	144,803
October	25.35	25.23	25.33	19,215	25.50	24.89	25.21	117,458
November	25.29	25.19	25.24	33,026	25.31	25.05	25.20	108,412
December	25.24	25.17	25.21	23,196	25.24	25.09	25.17	183,722

## Prior Sales

For information in respect of share issuances related to the exercise of stock options and our dividend reinvestment plan, see Note 14 to our annual Consolidated Financial Statements for the year ended December 31, 2010, which are incorporated by reference into this AIF.

## DIRECTORS

According to our Articles, Nexen must have between three and 15 directors. On February 11, 2009, the board set the size at 12 directors effective April 28, 2009.

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.

Name (Age)	Residence	Principal Occupation <sup>1</sup>	Other Directorships	Nexen Director Since
William B. Berry <sup>3</sup> (58)	Houston, Texas, United States	Retired oil executive Formerly: Executive Vice President of ConocoPhillips	Willbros Group, Inc.	2008
Robert G. Bertram <sup>3</sup> (66)	Aurora, Ontario, Canada	Retired pension investment executive Formerly: Executive Vice President of Ontario Teachers' Pension Plan Board	Mulvihill Capital Management Funds <sup>2</sup> The Cadillac Fairview Corporation Maple Leaf Sports and Entertainment Ltd.	2009
Dennis G. Flanagan <sup>3</sup> (71)	Calgary, Alberta, Canada	Retired oil executive	Canexus Income Fund (Chair)	2000
S. Barry Jackson (58)	Calgary, Alberta, Canada	Retired oil executive Formerly: Chair of Resolute Energy Inc. and Chair of Deer Creek Energy Limited	TransCanada Corporation (Chair) TransCanada PipeLines Limited (Chair) WestJet Airlines Ltd.	2001
Kevin J. Jenkins <sup>3</sup> (54)	Windsor, Berkshire, United Kingdom	President and Chief Executive Officer of World Vision International Formerly: Managing Director of TriWest Capital Partners	–	1996
A. Anne McLellan, P.C., O.C. (60)	Edmonton, Alberta, Canada	Counsel with Bennett Jones LLP, Barristers and Solicitors, and Distinguished Scholar in Residence at the University of Alberta in the Institute for United States Policy Studies Formerly: Member of Parliament for Edmonton Centre, Deputy Prime Minister, Minister of Public Safety and Emergency Preparedness and Minister of Health	Agrium Inc. Cameco Corporation	2006
Eric P. Newell, O.C. (66)	Edmonton, Alberta, Canada	Retired oil executive	–	2004
Thomas C. O'Neill <sup>3</sup> (65)	Toronto, Ontario, Canada	Retired chartered accountant	Adecco S.A. (Vice Chair) BCE Inc. (Chair) Loblaw Companies Limited The Bank of Nova Scotia	2002
Marvin F. Romanow (55)	Calgary, Alberta, Canada	President and CEO of Nexen Formerly: Executive Vice President and CFO of Nexen	–	2009
Francis M. Saville, Q.C. (72)	Calgary, Alberta, Canada	Chair of Nexen Formerly: Counsel with Fraser Milner Casgrain LLP, Barristers and Solicitors	–	1994
John M. Willson (71)	Vancouver, British Columbia, Canada	Retired mining executive	–	1996
Victor J. Zaleschuk <sup>4</sup> (67)	Calgary, Alberta, Canada	Retired oil executive	Agrium Inc. Cameco Corporation (Chair)	1997

<sup>1</sup> Current and within the past five years.

<sup>2</sup> An investment management fund organization managing a series of closed-end funds listed on the TSX. Mr. Bertram is an Audit Committee member for each of these funds.

<sup>3</sup> Financial experts on Nexen's Audit Committee.

<sup>4</sup> Mr. Zaleschuk was President and CEO of Nexen from 1997 to 2001.

## 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 Gas Trust
Jackson	Cordero Energy Inc., Resolute Energy Inc., Deer Creek Energy Limited
Newell	Canfor Corporation
O'Neill	Dofasco Inc., Ontario Teachers' Pension Plan Board
Romanow	Canexus Income Fund
Saville	Mullen Transport Inc.
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 <sup>1,2</sup> (6)	Compensation <sup>1</sup> (7)	Governance <sup>1</sup> (7)	Finance <sup>1</sup> (7)	HSE & SR <sup>1</sup> (7)	Reserves <sup>1</sup> (7)
<b>Management Director—Not Independent</b>						
Marvin F. Romanow						
<b>Independent Outside Directors</b>						
William B. Berry <sup>3</sup>	√	√			√	Chair
Robert G. Bertram <sup>3,4</sup>	√		√	√		
Dennis G. Flanagan <sup>3</sup>	√			√	√	√
S. Barry Jackson		√	Chair	√		√
Kevin J. Jenkins <sup>3</sup>	√	Chair	√	√		
A. Anne McLellan, P.C., O.C.		√	√	√	√	
Eric P. Newell, O.C.	√		√		Chair	√
Thomas C. O'Neill <sup>3,5,6</sup>	Chair	√	√			√
Francis M. Saville, Q.C.		√	√	√	√	
John M. Willson		√			√	√
Victor J. Zaleschuk				Chair	√	√

<sup>1</sup> All members are independent. All Audit Committee members are independent and financially literate under additional regulatory requirements applicable to them.

<sup>2</sup> 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.

<sup>3</sup> Audit Committee financial expert under US regulatory requirements.

<sup>4</sup> Mr. Bertram is a board member and participates in the audit committee function for six 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 Nexen director and committee member.

<sup>5</sup> The board determined that Mr. O'Neill's service on the audit committees of three other public companies does not impair his ability to serve as Chair of Nexen's Audit Committee. The board considered that Mr. O'Neill has over 30 years of experience as a chartered accountant and, since retiring as Chair of PwC Consulting in 2002, his only business commitments are to the boards and committees on which he serves.

<sup>6</sup> The board extended Mr. O'Neill's Audit Committee Chair term to provide continuity in leadership in light of recent changes to committee membership and IFRS conversion.

## 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 and have experience preparing, auditing, analyzing or evaluating financial statements or supervising individuals engaged in those roles. Each Audit Committee member's education and experience is described below.

### Audit Committee Education and Experience

Name	Experience
<b>Berry</b>	<p>William Berry is a retired oil and gas executive. He was formerly Executive Vice President of ConocoPhillips from 2003 to 2008. 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.</p> <p>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 had finance managers reporting directly to him on a functional basis. He held various management roles, including Manager, Corporate Planning and Budgeting.</p>
<b>Bertram</b>	<p>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 had oversight of the pension fund's growth to \$108.5 billion from \$19 billion when it was established in 1990. Prior to that, he spent 18 years at Telus Corporation, formerly Alberta Government Telephones, where his responsibilities included investment management, the capital procurement program, corporate risk management, tax and compliance. Before leaving Telus, he was Assistant Vice President and Treasurer.</p> <p>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.</p>
<b>Flanagan</b>	<p>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 as 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.</p> <p>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, including as the Chief Financial Officer (CFO) and Executive Vice President.</p>
<b>Jenkins</b>	<p>Kevin Jenkins is President and Chief Executive Officer of World Vision International. He was formerly a Managing Director of TriWest Capital Partners, an independent private equity firm, from 2003 to 2009. He was President, CEO and a director of The Westaim Corporation from 1996 to 2003. From 1985 to 1996, he held senior executive positions with Canadian Airlines International Ltd. (Canadian). Mr. Jenkins was elected to Canadian's Board of Directors in 1987, appointed President in 1991 and appointed President and CEO in 1994. Earlier in his career he was CFO of Canadian.</p> <p>Mr. Jenkins has a Bachelor's Degree in Law from the University of Alberta and a Masters of Business Administration from Harvard Business School. He has worked in management positions with increasing levels of responsibility, including Assistant Treasurer, Vice President Finance, Executive Vice President and Chief Financial Officer, and President and CEO.</p>
<b>Newell</b>	<p>Eric Newell is the retired Chancellor of the University of Alberta, a position he held from 2004 to 2008. He is the retired Chair and CEO of Syncrude Canada Ltd. (Syncrude), positions he held from 1994 and 1989, respectively, until 2004. He served as President of Syncrude from 1989 to 1997. Prior to that, he was Vice President Finance and Administration. With over 14 years experience as CEO, Dr. Newell has had CFO's, Controllers and various finance managers report directly to him on a functional basis.</p> <p>Dr. Newell holds a Bachelor of Applied Science degree in Chemical Engineering from the University of British Columbia and a Masters of Science in Management Studies from the University of Birmingham, England.</p>
<b>O'Neill</b>	<p>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.</p> <p>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.</p>

The Audit Committee mandate is included in Appendix A, on page 63 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](http://www.nexeninc.com). Shareholders wishing to receive a copy of these documents may contact the Governance Office by telephone at 403.699.4926, or by email at [governance@nexeninc.com](mailto:governance@nexeninc.com).

## INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS (IRCA) FEES

### Pre-Approval Policies and Procedures

Nexen has adopted the following 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 the services 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.

IRCA services that arise that were not pre-approved by the Audit Committee must be pre-approved by the Audit Committee chair. The Audit Committee is informed of the services at its next 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 2009 or 2010.

### IRCA Fees Billed

The following table provides information about the fees billed to Nexen for professional services rendered by the IRCA during 2010 and 2009.

Type of Fee	Billed in 2009	Billed in 2010	Percentage of Total Fees Billed in 2010
Audit Fees <sup>1</sup>	3,591,321	3,252,415	63%
Audit-Related Fees <sup>2</sup>	1,786,308	1,727,203	33%
Tax Fees <sup>3</sup>	151,269	59,251	1%
All Other Fees <sup>4</sup>	262,848	163,975	3%
<b>Total Annual Fees</b>	<b>5,791,746</b>	<b>5,202,844</b>	<b>100%</b>

<sup>1</sup> Audit fees were paid to the IRCA for the audit of Nexen's and Canexus' annual financial statements or services provided in connection with statutory and regulatory filings or engagements.

<sup>2</sup> 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.

<sup>3</sup> Tax fees were paid to the IRCA for tax compliance services and tax-related consultation.

<sup>4</sup> Other fees were paid to the IRCA for subscriptions to auditor-provided and supported tools.

## EXECUTIVE OFFICERS

The board determines the term of office for each executive officer. Below are Nexen's executive officers, 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.

<b>Officer (Age)</b>	<b>Residence</b>	<b>Current and Past Position(s)</b>	<b>Effective Date of Current Position</b>	<b>Executive Officer Since</b>
Marvin F. Romanow (55)	Calgary, Alberta, Canada	President and CEO and a director. Formerly: Executive VP and CFO since June 1, 2001.	January 1, 2009	1997
Kevin J. Reinhart (52)	Calgary, Alberta, Canada	Executive VP and CFO. Formerly: 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.	April 27, 2010	1994
Matthew J. Fox (50)	Calgary, Alberta, Canada	Executive VP, International. Formerly: President and CEO at Conoco-Phillips Canada since July 2009; Senior VP, Oil Sands at Conoco-Phillips Canada since 2007; Manager of North Slope Development in Alaska at Conoco-Phillips since 2003.	April 1, 2010	2010
Gary H. Nieuwenburg (52)	Calgary, Alberta, Canada	Executive VP, Canada. Formerly: Senior VP, Synthetic Crude since November 1, 2007; VP, Synthetic Crude since July 11, 2002.	May 1, 2009	2001
James T. Arnold (51)	Calgary, Alberta, Canada	Senior VP, Synthetic Crude. Formerly: Division VP Operations and Projects, Synthetic Oil since February 1, 2009; Chief Operating Officer at OPTI Canada Inc. since October 13, 2005.	July 16, 2009	2009
Eric B. Miller (48)	Calgary, Alberta, Canada	Senior VP, General Counsel and Secretary. Formerly: VP, General Counsel and Secretary since July 11, 2007; Division VP and Chief Legal Counsel since July 1, 2006; Division VP, Legal Canadian Oil and Gas since March 1, 2002.	April 27, 2010	2007
Una M. Power (46)	Calgary, Alberta, Canada	Senior VP, Corporate Planning and Business Development. Formerly: VP, Corporate Planning and Business Development since January 16, 2009; Treasurer since July 11, 2002.	April 27, 2010	1998
Brian C. Reinsborough (49)	Dallas, Texas, United States	Senior VP, United States Oil and Gas. Formerly: Division VP, Exploration, Operations and Production since May 12, 2006; Division VP, Exploration since July 8, 2002.	November 1, 2007	2007
Catherine J. Hughes (48)	Calgary, Alberta, Canada	VP, Operational Services, Technology and Human Resources. Formerly: Division VP, Operational Services, Technology and Human Resources since December 1, 2009; Division VP, Operational Services and Technology 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.	February 17, 2010	2010
Kim D. McKenzie (62)	Calgary, Alberta, Canada	VP and Chief Information Officer. Formerly: Division VP, Information Technology since January 1, 1992.	November 1, 2007	2007
Kevin J. McLachlan (47)	Calgary, Alberta, Canada	VP, Global Exploration. 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
Brendon T. Muller (42)	Calgary, Alberta, Canada	Controller. Formerly: Manager, Corporate External Reporting since November 1, 2003.	April 9, 2007	2007
J. Michael Backus (40)	Calgary, Alberta, Canada	Treasurer. Formerly: Manager, Planning, Synthetic Crude since January 1, 2009; Project Planner—Phase 2 Long Lake, Synthetic Crude since April 1, 2005.	February 16, 2009	2009

## 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 Environmental Protection Agency, 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, 2010, 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, 2010, 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 is our transfer agent and registrar of the Company's common shares. They are located at:

CIBC Mellon Trust Company  
 199 Bay Street  
 Commerce Court West  
 Securities Level  
 Toronto, ON M5L 1G9

In the United States, BNY Mellon Shareowner Services is our transfer agent and registrar 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, 2010, 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 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 U.S. 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, 2010 incorporated by reference in this AIF has been compiled by the Company based on the report dated February 16, 2011 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 both 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](http://www.sedar.com) and on EDGAR at [www.sec.gov](http://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 2011 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](http://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 and the MD&A (Management's Discussion and Analysis of Financial Condition and Results of Operations), to be included in Nexen's Annual Report filed with Canadian and U.S. 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 U.S. regulatory agencies.
20. 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 cash flow or production guidance. Annual production and cash flow 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. 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. 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

22. 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.
23. Review the independent auditor's annual attestation of the internal control over financial reporting structure and procedures.
24. 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.
25. Review and approve the proposed annual Corporate Audit Plan including assessment of major risks, areas of focus, responsibilities and objectives, and staffing.
26. 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.

27. 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.
28. 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.
29. 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.
30. Review any appointment or dismissal of the senior internal audit executive (Director, Corporate Audit).
31. 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.
32. Review with Management and the independent auditor any off-balance sheet financing mechanisms, transactions or obligations of Nexen.
33. Regularly review with Management and the independent auditor any related party transactions.
34. 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.
35. Receive a report, at least annually, from Management on Nexen's community investment budget and Nexen and employee donations.

## Compliance

36. Prepare a letter for the annual report to shareholders and the Annual Report filed with Canadian and U.S. 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 the reconciliation of Nexen's financial statements to U.S. GAAP complies with the requirements of the Securities Exchange Act of 1934 (1934 Act).
37. Receive reports, as required, from Management, Nexen's Director, 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.
38. 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

39. Following each meeting of the Committee, report to the Board on the activities, findings and any recommendations of the Committee.
40. 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.
41. Annually review and approve the Committee's report for inclusion in the Proxy Circular.
42. Prepare any reports required to be prepared by the Committee under applicable law.

### Committee Meetings

43. 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.
44. Meet in separate, non-management, closed sessions with the Director, Corporate Audit at each regularly scheduled meeting.
45. Meet in separate, non-management, closed sessions with the independent auditor at each regularly scheduled meeting.
46. Meet in separate, non-management, in camera sessions at each regularly scheduled meeting.
47. Meet in separate, non-management, closed sessions with any other internal personnel or outside advisors, as needed or appropriate.

### Committee Governance

48. 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

49. Have the sole authority to retain, oversee, compensate and terminate independent advisors who assist the Committee in its activities.
50. 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

51. Carry out any other appropriate duties and responsibilities assigned by the Board.
52. To honor 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: December 6, 2010