

# OPERATIONS

We made significant progress in 2009 advancing our three growth strategies relating to oil sands, conventional exploration & development and unconventional gas.

## Part I

### ITEMS 1 AND 2: Business and Properties

About Us	1
Strategy	2
Positioned for Success—Focused on Value	3
Oil and Gas	4
Understanding the Oil and Gas Business	6
Athabasca Oil Sands	7
Conventional Exploration and Development	12
Unconventional Gas	22
Reserves, Production and Related Information	23
Energy Marketing	34
Chemicals	35
Government and Environmental Regulations	36
Employees	40
ITEM 1A: Risk Factors	40
ITEM 1B: Unresolved Staff Comments	48
ITEM 3: Legal Proceedings	48
ITEM 4: Submission of Matters to a Vote of Security Holders	48

## Part II

ITEM 5: Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	48
ITEM 6: Selected Financial Data	50

# PART I

## ITEMS 1. AND 2.

### Business and Properties

Certain statements in these items 1 and 2 constitute “forward-looking statements” and the reader should refer to the Special Note Regarding Forward-Looking Statements set out on page 96 of this Form 10-K.

## ABOUT US

Nexen Inc. (Nexen, we or our) 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.

In the 1970s, we broadened our western Canadian asset base and entered the US Gulf of Mexico. In the 1980s, we grew our western Canadian and Gulf of Mexico assets through acquisitions and captured an interest in Syncrude. In the 1990s, we had two defining events—first, we discovered the first of 17 fields at Masila in Yemen in 1990 and commenced production in 1993. Second, we tripled our Canadian production in 1997 by purchasing Wascana Energy Inc. We leveraged our success in Yemen and Western Canada to fund our growth elsewhere and today we are focused on three strategic growth areas: i) oil sands, including our 65% operated interest in the Long Lake project and our interest in Syncrude; ii) conventional

exploration and development properties in our core areas including the North Sea, US Gulf of Mexico, Canada, Yemen and offshore West Africa; and iii) unconventional gas focused on our shale gas play in northeastern British Columbia.

We’ve grown from producing 10,700 boe/d before royalties with revenues of \$26 million in 1971, to producing over 240,000 boe/d before royalties and revenues of \$5.8 billion in 2009. We achieved this growth through exploration success and strategic acquisitions. Operating for almost 40 years, we have been profitable every year, except one, and have been paying quarterly dividends consecutively since 1975.



Long Lake Oil Sands, Alberta, Canada



Buzzard, UK North Sea

## 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 exploiting our existing three key growth areas: i) oil sands; ii) select conventional exploration and development; and iii) unconventional gas.

### OIL SANDS

Our oil sands investments include interests in the Long Lake project, the Syncrude joint venture and our 735,000 undeveloped acres (gross) in the Athabasca oil sands in northern Alberta. Our oil sands strategy is designed to provide steady and predictable cash flow for decades.

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.

In 2001, we formed a 50/50 joint venture with OPTI Canada Inc. (OPTI) to develop, produce and upgrade bitumen on our joint lands in the Athabasca oil sands. Production utilizes our patented OrCrude™ technology, which we expect will ultimately result in at least a \$10/bbl margin advantage over conventional oil sands extraction and upgrading. Construction of the Long Lake project was completed in 2008 and we began producing Premium Synthetic Crude™ (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.

### CONVENTIONAL EXPLORATION AND DEVELOPMENT

Our conventional exploration and development is 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 returns 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. 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 discoveries including Pink, Hobby and Golden Eagle in the Golden Eagle area; Blackbird; and Rochelle. We continue to actively explore the basin including relatively under-explored areas such as west of the Shetland Islands and in Norway.

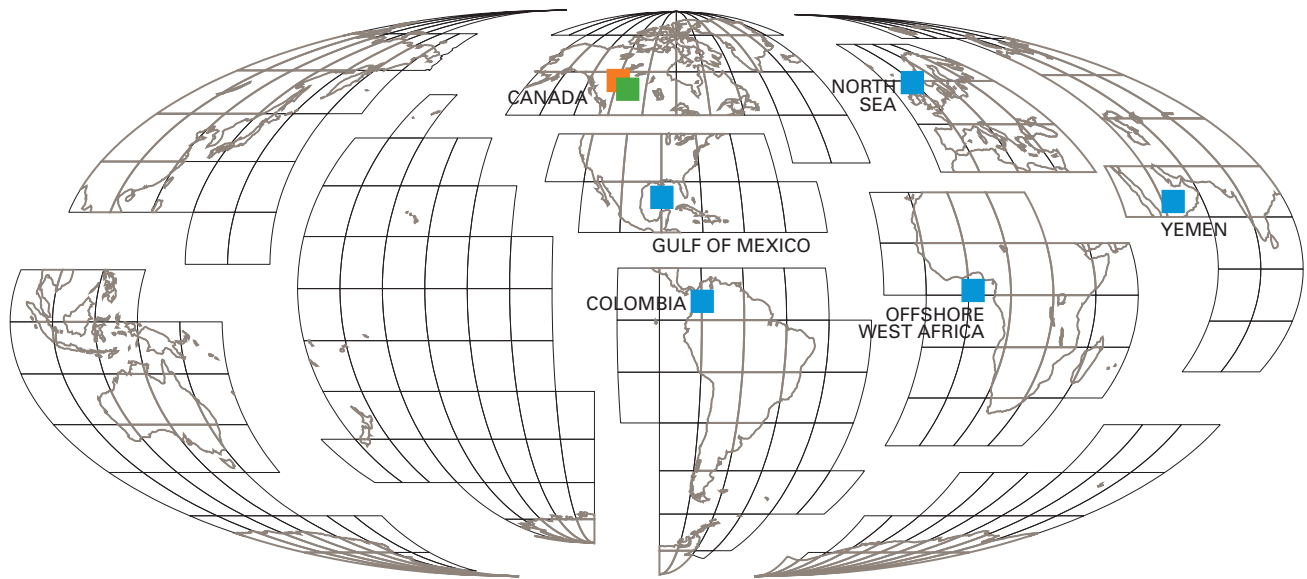
In the deep-water Gulf of Mexico, we made several significant discoveries including Gunnison, Aspen, Knotty Head, Wrigley and Longhorn. We accumulated a large inventory of deep-water acreage and are a significant leaseholder in the Gulf. The deep-water Gulf is near infrastructure and continental US markets, so discoveries can be brought on stream in a reasonable time.

We have several significant discoveries offshore West Africa, including Usan, Usan West and Ukot, as well as our most recent success at Owowo South, offshore Nigeria. We are progressing the Usan field development with a floating production and storage offloading (FPSO) vessel and subsea facilities for scheduled first production in 2012.

### UNCONVENTIONAL GAS

Our unconventional gas strategy is currently focused primarily on the Horn River Basin in northeast British Columbia. The Horn River Basin is emerging as a significant shale gas play with high resource density and excellent well productivity. We have a substantial land position in the Horn River Basin, with approximately 90,000 acres in the Dilly Creek area and 38,000 acres in the Cordova area, with a 100% working interest in each.

Shale gas complements our corporate portfolio, which consists predominantly of large-scale, and capital-intensive, long cycle-time projects. It provides natural gas exposure and short cycle-time projects where we control the scale and pace of development.



## 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 growth in long-term value. 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 hold 199 net sections in the emerging 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.

### 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 Vicksburg in the Gulf of Mexico, the Golden Eagle area in the UK North Sea and Usan and Owowo South, offshore Nigeria. We are ramping up production at Long Lake and continue to advance our shale gas play in the Horn River Basin. Our production has grown at a compounded annual growth rate of over 10% for the last three years.

## FINANCIAL STRENGTH

- Strong financial position—we have access to over \$3 billion of liquidity through cash and undrawn committed credit facilities that will allow us to proceed with investments at our pace and to take advantage of organic and other 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, the United Kingdom, Nigeria, Colombia and Australia.
- Employer of choice—proven ability to retain and attract talent (Hewitt Top 50 Employer in Canada).
- Skilled workforce—we significantly enhanced our technical skills over the last few years by hiring experienced employees for our Long Lake, 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.
- Leadership—industry leader in governance, community relations and environmental stewardship.

For financial reporting purposes, we report on three main segments:

- oil and gas;
- energy marketing; and
- chemicals.

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 are included in Canada. Energy Marketing includes our crude oil, natural gas, natural gas liquids and power marketing businesses in North America, Europe and Asia. Chemicals includes operations in North America and Brazil that manufacture, market and distribute sodium chlorate, caustic soda, muriatic acid and chlorine through the Canexus Income Fund.

Production, revenues, net income, capital expenditures and identifiable assets for these segments appear in Note 20 to the Consolidated Financial Statements and in Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) in this report. Reserves for our oil and gas operations appear on page 23.

## 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 Form 10-K, 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. Our reserves estimates and related disclosures have been prepared in accordance with the definitions and disclosure requirements prescribed by the United States Securities and Exchange Commission (SEC). Our reserve estimates and disclosures may differ from other Canadian issuers who follow Canadian disclosure standards as set out in National Instrument 51-101—*Standards of Disclosure for Oil and Gas Activities* (NI 51-101). Significant differences between SEC and Canadian reserves estimates and disclosures are described on page 97 (see Special Note to Canadian Investors).

On December 31, 2008, the SEC issued final revised rules relating to reserve definitions and related disclosure requirements. These new rules are effective for estimates and disclosures made on or after January 1, 2010, including those in this report. The primary impacts of changes on our reserves estimates resulting from the adoption of the new rules are as follows:

- our Syncrude oil sands activities are now considered an oil and gas activity rather than a mining activity. This impacts the classification of the reserves but does not result in a change in the estimate of reserves;
- reserves quantities are now based on the final product sold after field upgrading rather than the product initially produced. This results in presenting our Long Lake oil sands reserves as synthetic oil barrels rather than bitumen barrels. This results in a reduction in quantity reflecting the removal of the asphaltenes from the bitumen barrel, which we gasify for use as our internal fuel source in the steam generation, upgrading and cogeneration power processes;
- prices underlying our economic assumptions used for reserves estimation are now based on the average first-day-of-the-month prices during the year, rather than the prices on December 31 each year; and
- we are voluntarily disclosing probable reserves in addition to proved reserves in this Form 10-K.

The impact of the new rules on our reserves estimates also requires us to modify our reserves disclosures this year to transition our reserves estimates from the old rules to the new rules. We have chosen to report our transition to the new rules in a manner that we believe best illustrates the impact of the changes on our reserves estimates and allows us to clearly present how our reserves estimates changed during 2009 as a result of our operational activities separate from the adoption of the new rules. Accordingly, throughout this report, we have reported the impact of the new rules on our December 31, 2009 reserves estimates as follows:

- the impact of the new rules on our proved reserves estimates has been shown separately in each table in a line titled SEC Rule Transition, except for the impact of the change in the pricing rule. The new pricing rule was used in the preparation of the 2009 reserves estimates, so there is no separate adjustment for this

change. The prices underlying the year-end reserves estimates under the old and new rules change each year, and are a key determinant of whether the reserves are economic. Given its pervasive impact on the reserves estimates for each property, we felt it was most efficient to use the new pricing rule;

- we have segregated changes in reserves estimates in transitioning from the old rules to the new rules between those that pertain to the prior year's estimates and those pertaining to changes in reserves during the year. We feel this additional information is helpful in understanding the impact of the changes on the current year's activities;
- since we reported certain information with respect to Syncrude's proved reserves in our prior Form 10-Ks, we included such information in our prior years' reserves balances as if it was always an oil and gas activity. We have also presented a portion of the previously reported mining reserves as proved undeveloped reserves at December 31, 2008, by applying the oil and gas definitions. We feel this improves the consistency of reserves reporting, eliminates confusion that may arise by including the prior years' information in a different place in this report and allows for better presentation of the activities during 2009; and
- since we reported probable reserves estimates in other disclosure documents in prior years, we have presented a continuity schedule as if they had been reported in our Form 10-K last year. This allows the probable reserves information to be presented consistently in our various reporting documents and provides for disclosure of changes in our probable reserves during 2009. Probable reserves estimates in prior years were prepared in accordance with NI 51-101 and the Canadian Oil and Gas Evaluation Handbook standards. Similar to the manner in which we have presented the impact of the new SEC rules on our proved reserves estimates, the impact of converting our 2008 probable reserves estimates to the new SEC rules is shown separately in each probable reserves table on the lines titled SEC Rule Conversion, except for the impact of the new pricing rule, which was used in preparation of the 2009 reserves estimates. See page 27 for a description of probable reserves.

Our proved and probable reserve estimates are internally prepared. We had 98% of our proved reserves before royalties (98% after royalties) assessed (either evaluated or audited as described on page 29) 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 the difference on the portfolio of properties to within 10% in the aggregate. Estimates pertaining to individual properties within the portfolio may differ by more than 10%, either positively or negatively; however, we believe such differences are not material relative to our total proved reserves.

We also had 98% of our proved plus probable oil and gas reserves before royalties (98% after royalties) assessed by independent reserves consultants. By definition, probable reserves must be determined together with proved reserves (see definition on page 27). 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 the difference on the portfolio of properties to within an acceptable tolerance for the aggregate. Estimates pertaining to individual properties within the portfolio may differ by more than the acceptable tolerance, 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 page 29 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 BUSINESS

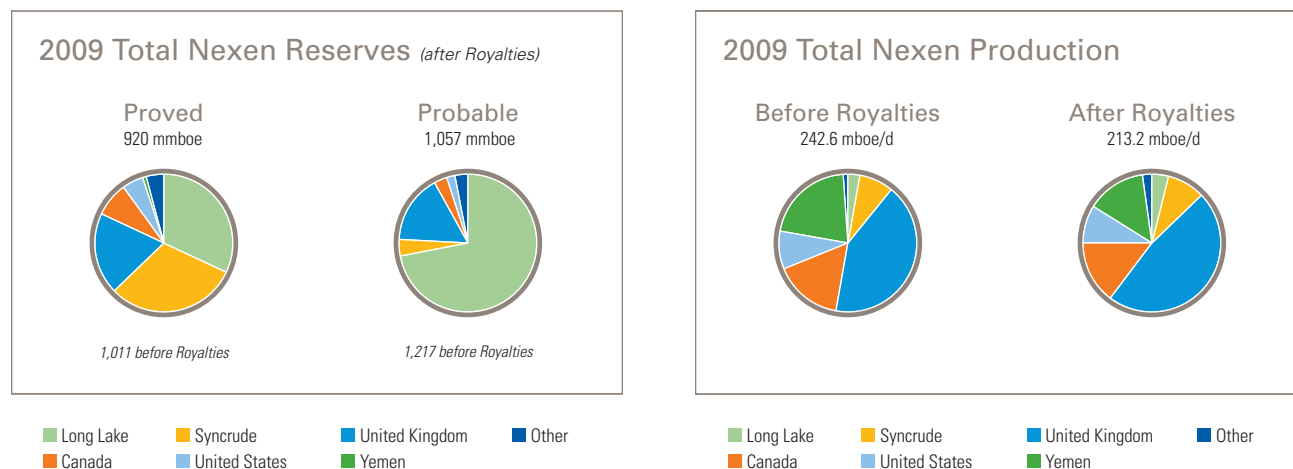
The oil and gas industry is highly competitive. With strong global demand for energy, there is intense competition to find and develop new sources of supply. Yet, barrels from different reservoirs around the world do not have equal value. Their value depends on the costs to find, develop and produce the oil or gas, the fiscal terms of the host regime and the price that products command in the market based on quality 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 operating activities. 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. We maintain liquidity that provides us with the ability to invest in high-quality projects that we believe will generate value over the long term.

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 can fluctuate season to season, which impacts price. In particular, natural gas is generally in higher demand in the winter for heating. 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.

## Nexen Consolidated Reserves and Production

In the charts below, our consolidated proved and probable reserves as at December 31, 2009 are presented, along with our oil and gas production for the year ended December 31, 2009.

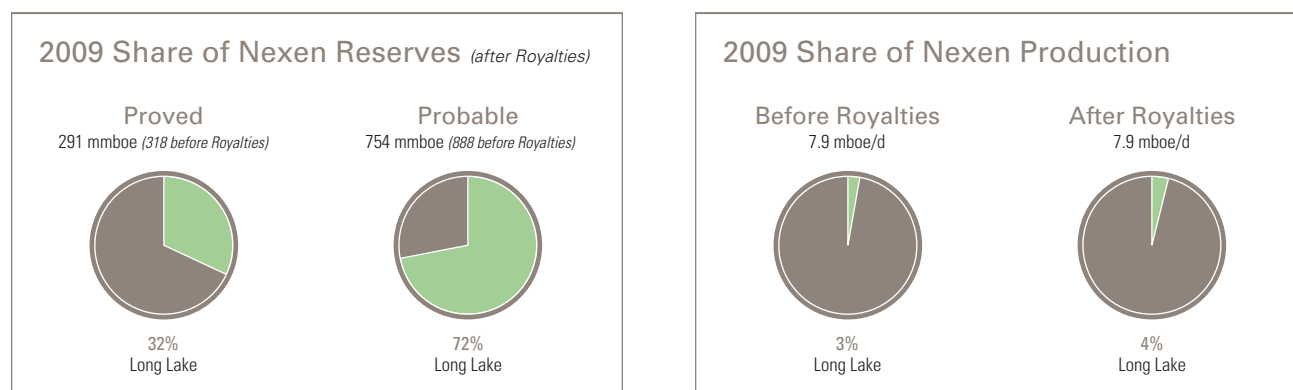


## ATHABASCA OIL SANDS

- We made significant progress in the year proving that we can gasify the bottom of the bitumen barrel for internal fuel and upgrade the residual to a Premium Synthetic Crude™ (PSC™) oil.
- We have significant undeveloped acreage in the Athabasca oil sands, totalling over 700,000 acres (gross).
- Syncrude, which mines the oil sands and produces synthetic crude oil, has been operating for almost 35 years.

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 operation.

### Synthetic (Insitu Long Lake)

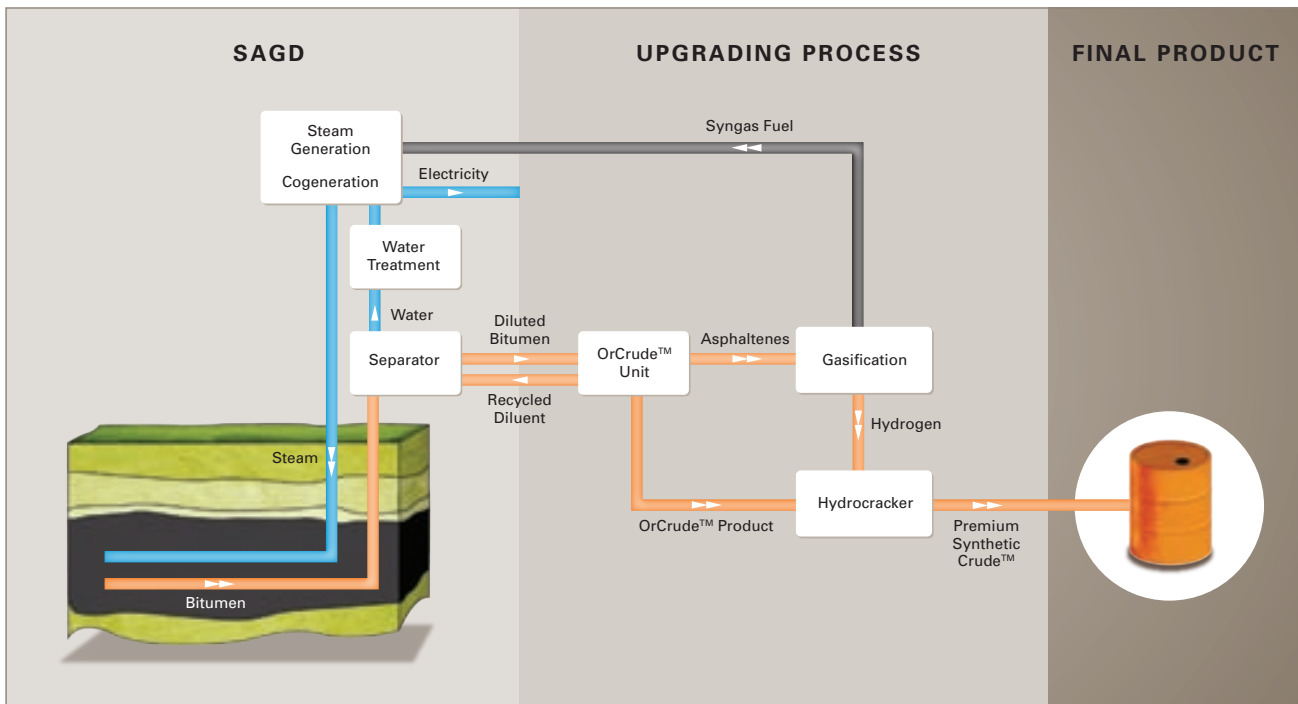


In 2001, we formed a 50/50 joint venture with OPTI to develop the Long Lake lease using SAGD for bitumen production and proprietary OrCrude™ technology for the first stage of upgrading. OPTI has the exclusive Canadian licence for the OrCrude™ technology. We acquired the exclusive right to use this technology with OPTI within approximately 100 miles 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 January 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 as well as for future phases.

### SAGD AND UPGRADER INTEGRATION

The SAGD process involves drilling two parallel horizontal wells, 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 asphaltene. By coupling the OrCrude™ process with commercially available hydrocracking and gasification technologies, sour crude oil is upgraded to light (39° API) premium synthetic sweet crude oil, and the asphaltene is 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 burned 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, which we expect will provide us with an approximate \$10/bbl margin advantage in the long term.



## OUR STRATEGIC ADVANTAGE

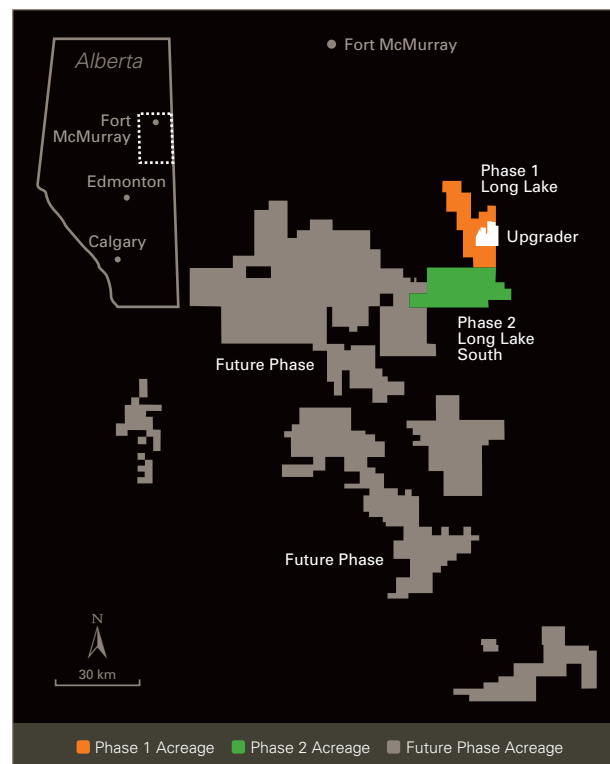
Our integrated SAGD and upgrading process addresses three main economic hurdles of SAGD bitumen production: i) the potential high cost of natural gas; ii) the cost and availability of diluent; and iii) the typically lower realized price of bitumen. With synthetic gas from the asphaltenes as fuel, we 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 light, sweet crude oil premium pricing.

## PHASE 1

The Long Lake project received regulatory approval in 2003 and was sanctioned in 2004. Field construction of the SAGD and upgrader facilities began in 2004. In 2006, we substantially completed module and site construction of the SAGD facilities, and in late 2007, we began injecting steam into the well pads. We continued to steam the SAGD well pairs and began turning wells over to SAGD production in 2008. Our steam generation was initially restricted by our ability to treat water during ramp-up as most of the water we inject into the reservoir is recycled and treated. In response to this, we implemented a number of low-cost changes to the water treating system, which include adding supplementary heat to the hot lime softeners and improvements to our filtration system. This work was completed in 2009, at which time we also completed work to remove deposits that typically build up in water treatment facilities. Later in 2009, we replaced valves, cleaned out the hot lime softeners and isolated the water-treatment trains. We also took the opportunity to perform a number of other maintenance activities to improve reliability and operability, including installing electric submersible pumps (ESPs) in a number of our SAGD wells. 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, steam-to-oil ratios are high but will decline as bitumen production ramps up to our target rates. We expect the steam-to-oil ratio to reach approximately 3.0 over the long term.

We completed construction of the upgrader in 2008 and began commissioning for commercial operations. Initial production of Premium Synthetic Crude™ oil from the upgrader began in January 2009. As the upgrader ramps up to capacity, we expect that there will be 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. During the bitumen ramp-up period, we are purchasing third-party bitumen to assist with upgrader start-up. Production capacity for the first phase of Long Lake is approximately 60,000 bbls/d (39,000 net 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.



Bitumen production for 2009 averaged 7,900 bbls/d (12,200 gross). We are currently producing approximately 18,000 bbls/d of bitumen (11,700 bbls/d, net to us) following maintenance and debottlenecking work completed late in 2009. Late in the year, we were processing about 90% of our produced bitumen along with 9,000 bbls/d of purchased third-party bitumen in the upgrader, yielding about 16,000 bbls/day of PSC™.

We expect to achieve positive economic returns, that benefit from a significant operating cost advantage. Combined SAGD, cogeneration and upgrading operating costs are expected to average about \$25/bbl, substantially lower than coking or other upgrading processes as a result of the reduced need to purchase natural gas. We expect ongoing capital 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. Our technology will however add at least a \$10/bbl margin advantage as we extract energy (for steam generation and power) and hydrogen (for upgrading) from a portion of the barrel others (cokers) discard.

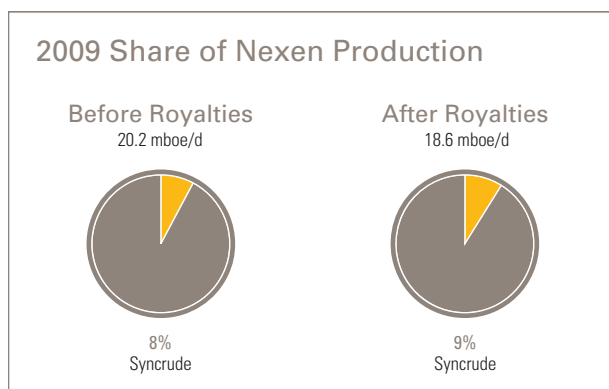
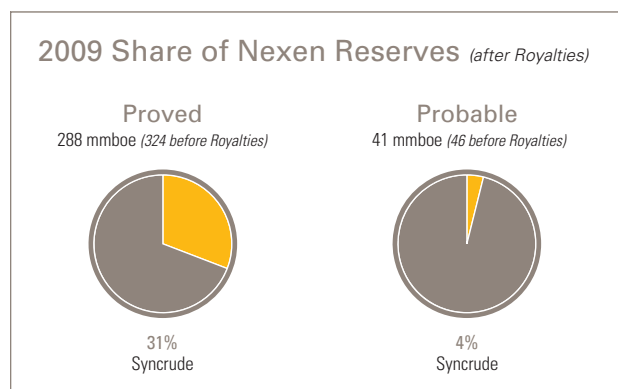
## Syncrude

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.

## FUTURE PHASES

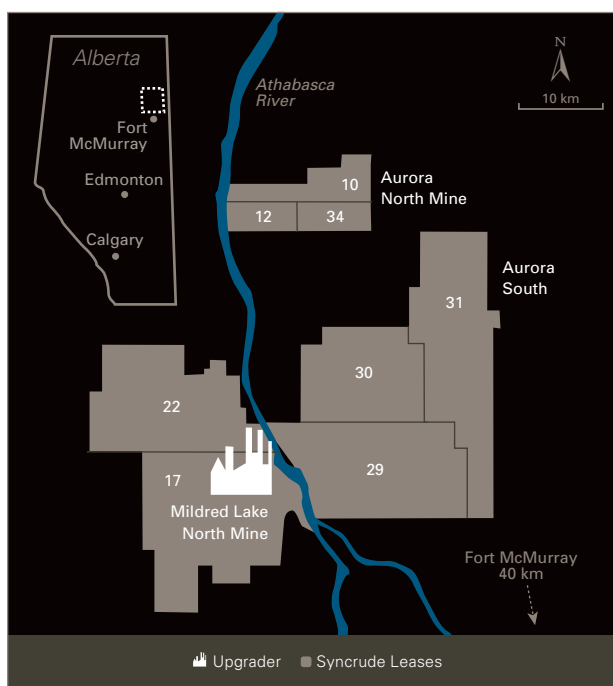
We have approximately 309,000 net acres of bitumen-prone lands in the Athabasca region. We plan to continue developing our bitumen lands in phases using our integrated SAGD and upgrading strategy. In 2009, we invested \$100 million on land acquisition, additional drilling, seismic and engineering to develop our leases and advance regulatory applications for future phases.

Federal government climate change legislation has not yet been finalized. Due to this regulatory uncertainty and the ongoing ramp-up of Phase 1, we are delaying certain planned expenditures on Phase 2. Phase 2 is expected to be followed by additional phases every three or four years. Each phase will leverage the knowledge and experience gained from successfully developing Long Lake, and subsequent projects are expected to be similar in size and design. 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 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 hectares, 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 2009, about 50% of the synthetic crude oil was sold to Edmonton area refineries, and the remaining 50% was sold to refineries in Eastern Canada and the mid-western United States. 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 again in 2009 to accommodate increased Syncrude production.

At December 31, 2009, our total net book value of property, plant and equipment, including surface mining facilities, transportation equipment and upgrading facilities, was approximately \$1.2 billion. Based on development plans, our share of future expansion and equipment replacement costs over the next 35 years is expected to be about \$5.7 billion.

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 25 miles 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 a royalty 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 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 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

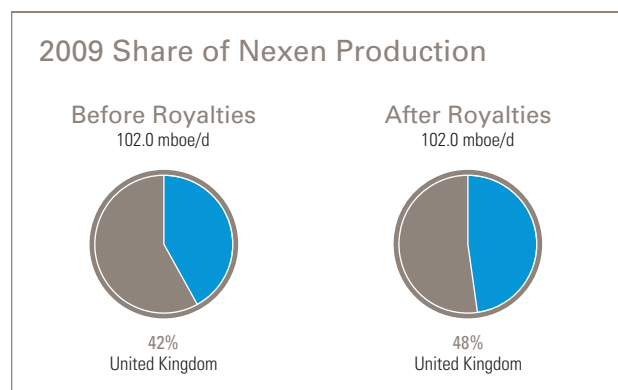
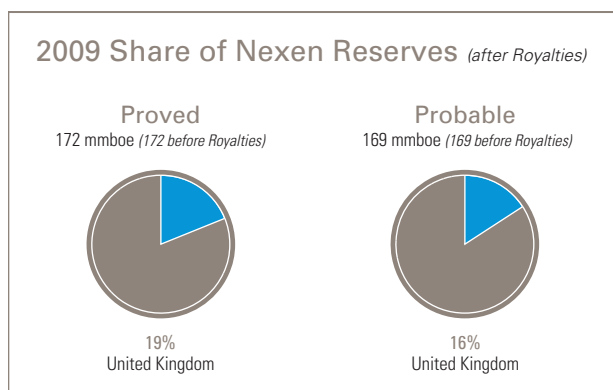
recaptured by the Alberta government over a 25-year period. In addition, the Province of Alberta and Syncrude reached an agreement to establish new transitional royalty terms. Under the terms of the agreement, until December 31, 2015, Syncrude will continue to pay base royalty rates (being the greater 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 become effective January 1, 2009. After January 1, 2016, the rates under the new royalty framework will apply to the Syncrude project. See Canada fiscal terms on page 16.

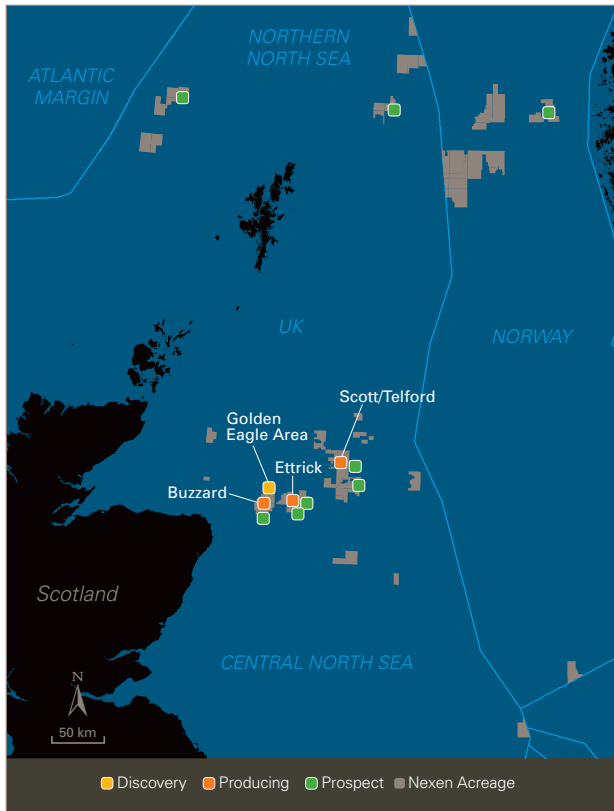
## CONVENTIONAL EXPLORATION AND DEVELOPMENT

### United Kingdom (UK)

- We are the second largest oil producer in the UK North Sea.
- We have recent exploration success in the Golden Eagle area, with potential development sanctioning in late 2010/early 2011.
- We continue to actively explore the North Sea, with eight exploration and appraisal wells planned for 2010.



The UK North Sea is a key producing area for Nexen. Our primary assets here include a 43.2% operated interest in the Buzzard field and facilities, a 41.9% operated interest in the Scott field and production platform, a 71.8% operated interest in the Telford field and a 79.7% operated interest in the Ettrick field, along with interests in several undeveloped discoveries and more than 750,000 net undeveloped exploration acres. We are a significant regional player with concentrated assets, infrastructure and exploration potential for future growth. Our North Sea operations have high-margin reserves and production, diversify our global portfolio with strong assets in a stable jurisdiction and complement our other longer cycle-time projects.



Our UK strategy is to grow and sustain our existing North Sea production and identify new production sources with exploration and exploitation opportunities near existing infrastructure. We have a number of exploitation opportunities in our existing fields and undeveloped discoveries near infrastructure. Most of our unexplored acreage is near Scott/Telford, Buzzard or Ettrick and can be tied-in 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.

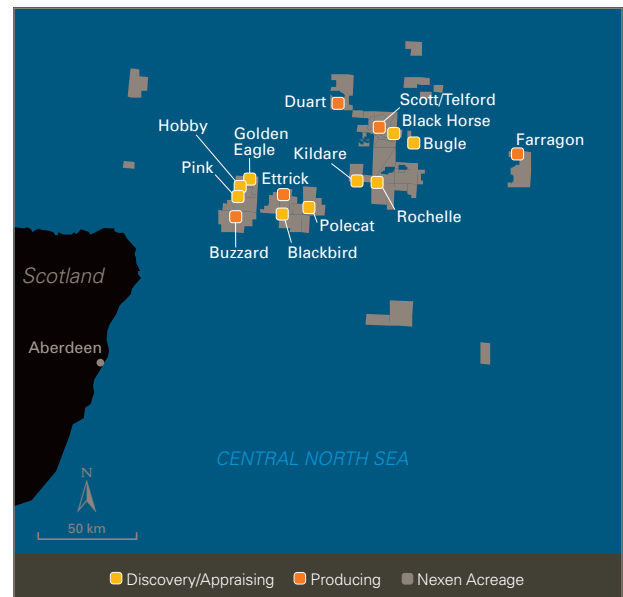
The Buzzard field is located about 60 miles northeast of Aberdeen in the Outer Moray Firth, central North Sea, in 317 feet of water. The Buzzard development initially is comprised of three platforms capable of processing at least 200,000 bbls/d of oil and 60 mmcf/d of gas. Oil from Buzzard is exported 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.

Initial development drilling resulted in more well-to-well variability in the concentration of hydrogen sulphide than was originally expected. To address this, we are constructing a fourth platform with production-sweetening facilities to handle higher levels of hydrogen sulphide. The fourth platform jacket was installed during 2009. In 2010, we plan to install the deck of the fourth platform and tie it in to the existing platforms. At the current levels of hydrogen sulphide being produced, we expect to require the oil-sweetening equipment in 2011.

We expect to produce the Buzzard field through 30 production wells and maintain reservoir pressure with an active water-flood program. We have drilled 21 of these wells, of which 16 are available for production. Our share of production in 2009 was 81,400 boe/d. We expect to drill six additional development wells in 2010.

### SCOTT/TELFORD

Scott and Telford are producing fields with additional exploitation opportunities and both tie back to the Scott platform. Scott was discovered in 1987 and began producing in September 1993, while Telford was discovered in 1991 and came on stream in 1996. 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. In 2009, we drilled the TAB well at Telford and three development wells at Scott. The TAB well exceeded our expectations and extended the field's proved reserves. Scott/Telford produced 13,500 boe/d in 2009. We are currently reviewing technical subsurface work to support drilling another development well at Telford and potentially install an additional Telford flowline back to the Scott platform.

## ETTRICK

The Ettrick subsea facilities and the majority of the leased floating production, storage and offloading vessel's (FPSO) systems were successfully commissioned in 2009 and the Ettrick development produced first oil in August 2009. We have successfully tested the FPSO up to its design rates. Commissioning of the water injection and gas systems was largely completed in 2009. Our 2009 share of production was 4,300 boe/d and we expect this to increase to between 11,000 and 15,000 boe/d in 2010 as we continue to ramp up and commission the facility. 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.

## 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; appraisal well planned for 2010
Black Horse	50	operated	discovery near Scott; evaluating development alternatives
Bugle	41	operated	discovery near Scott; appraisal well planned for 2010
Ferret (Polecat)	40	operated	discovery near Buzzard; appraisal well planned for 2010
Golden Eagle	34	operated	discovery near Buzzard; evaluating development alternatives
Hobby	34	operated	discovery near Golden Eagle; evaluating development alternatives
Kildare	50	operated	discovery near Scott; evaluating development alternatives
Pink	46	operated	discovery near Golden Eagle; evaluating development alternatives
Rochelle	44	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. During 2009, we successfully pursued a comprehensive appraisal program of the discoveries, which included drilling nine appraisal wells, two drill-stem tests and one injection test. With this success, we expect the Golden Eagle area will become a significant development over the next few years. In 2010, we will continue to complete the appraisal of the field and evaluate our development options. We also expect to complete the technical work necessary for project sanction in early 2011.

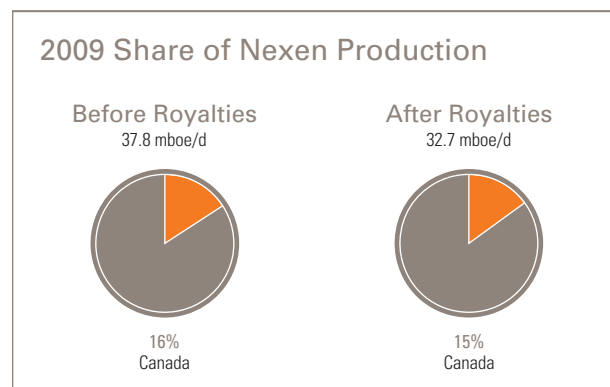
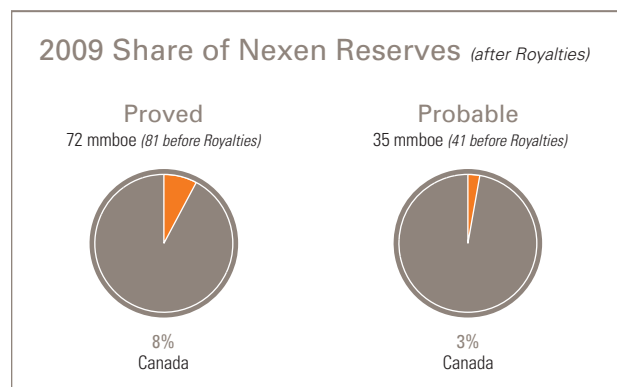
In 2010, we plan to drill an appraisal well at Blackbird, which we could tie back to the Ettrick FPSO if successful. Elsewhere in the UK North Sea, we plan to drill three exploration and two appraisal wells in 2010.

## 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 not expected before 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 also subject to a 20% supplemental charge.

## Canada

- Our shale gas land position in the Horn River Basin provides opportunities to significantly expand our gas reserves and production.
- Legacy assets provide steady and predictable cash flow to fund new growth initiatives.



In addition to our developments in the Athabasca oil sands, our strategy in Canada is three-fold: i) establish the Horn River Basin as a key growth area and continue to create value by exploring and developing the play; ii) generate new material resource play opportunities; and iii) optimize value from our producing assets.

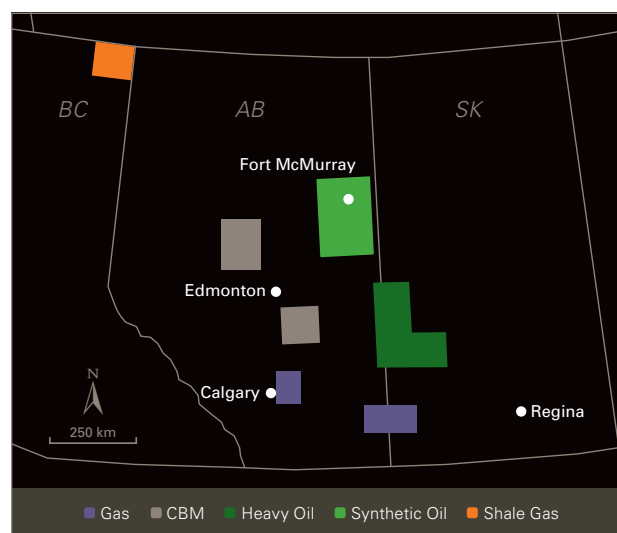
Our Canadian conventional producing assets include heavy oil production in east-central Alberta and west-central Saskatchewan and natural gas near Calgary and in southern Alberta and Saskatchewan. Our coalbed methane (CBM) assets in the upper Mannville and Horseshoe Canyon coals are located in Alberta with commercial production at

our Fort Assiniboine development over 50 mmcf/d in 2009. We operate most of our producing properties and hold almost one million net acres of undeveloped land across Western Canada (excluding Athabasca oil sands). These assets provide predictable production volumes and cash flow.

In 2009, we invested \$295 million in Canada, including \$203 million on our shale gas growth initiative. Our 2010 capital programs are focused on progressing our shale gas opportunities and evaluating material resource plays.

### HEAVY OIL

Approximately 45% of our Canadian production (excluding Athabasca oil sands) is from our heavy oil properties. Heavy oil is characterized by high specific gravity or weight and high viscosity or resistance to flow. Therefore, heavy oil is more difficult and expensive to extract, transport and refine than other types of oil. Heavy oil typically receives a lower price than light oil, as more expensive and complex refineries are required to refine heavy crude into higher-value petroleum products. To maximize heavy oil returns, it is important to manage capital and operating costs. Our large production base and existing infrastructure are advantageous in managing these costs. As part of an ongoing strategic review of our assets, we announced in late 2009 that we identified a number of non-core assets for possible disposal, including some or all of our heavy oil assets in Western Canada.



## NATURAL GAS

Approximately 32% of our Canadian conventional production is natural gas extracted primarily from shallow sweet reservoirs in southern Alberta and Saskatchewan and from sour gas reservoirs near Calgary. Generally, shallow gas targets are cheaper to drill and produce but have relatively smaller reserves and lower productivity per well. Sour gas is natural gas that contains hydrogen sulphide, which requires additional processing. Our Balzac field, northeast of Calgary, has been producing sour natural gas since 1961. This sour gas is processed through our operated Balzac plant, which went through a maintenance upgrade in 2008.

In southern Alberta and Saskatchewan, Colorado shale gas re-completions have the potential to add production on our existing acreage. As incremental production comes from existing wells and facilities, the economics are attractive.

## COALBED METHANE (CBM)

Approximately 23% of our Canadian conventional production is from our CBM developments at Corbett, Doris and Thunder in the Fort Assiniboine area of central Alberta. We began commercial operations in the Upper Mannville coals in 2005, progressively developing opportunities on our land base. We are applying horizontal well technology to increase gas production rates and reduce de-watering time from water-saturated coal. Upper Mannville coals are generally deeper than the Horseshoe Canyon "dry coal" play, which is also being commercially developed in Alberta. 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 5 to 40% depending upon drilling date, production rate and product sales price.

During 2008, the Alberta government legislated a new royalty framework for NPI and Gross Royalty structures effective January 1, 2009. The new 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 (Cdn\$55/bbl to Cdn\$120/ bbl). The amended Gross Royalty system increases the upper royalty rate limit to 50% and reduces the lower limit for conventional oil to nil, 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 25%.

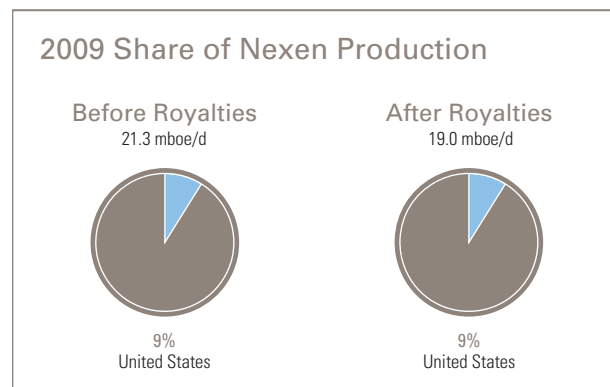
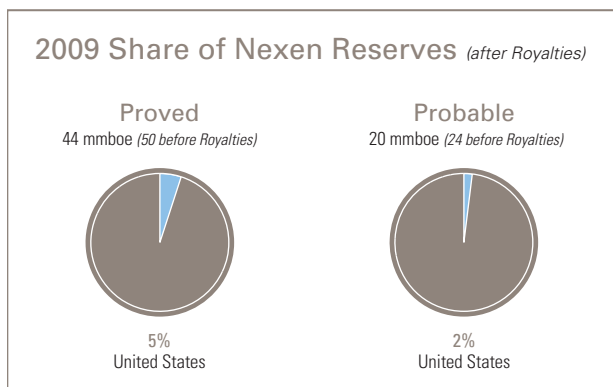
In 2009, the Alberta government commissioned a Competitiveness Review, which included a review of the provincial royalty system. Results of this review are not known at this time.

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%.

Profits earned in Canada from resource properties are subject to federal and provincial income taxes. These rates ultimately fall to 15% by 2012. In 2009, federal taxable income is taxed at 19% and will be taxed at 18% in 2010. Provincial income tax rates vary from approximately 10 to 16%.

## United States (US)—Gulf of Mexico

- We are a significant leaseholder in the deep-water Gulf of Mexico, which provides for future growth through exploration.
- We are appraising discoveries at Knotty Head and Vicksburg.
- Production from past discoveries provides liquidity for future exploration.



The Gulf of Mexico is an integral part of our longer-term growth strategy. Existing production infrastructure, the potential for large 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, deep-water prospects generally have multiple sands and higher production rates—factors that enhance economics. The technology to find, drill and develop deep-water discoveries is rapidly progressing and becoming more cost effective. The deep-water Gulf is near infrastructure and continental US markets, so discoveries can be brought on stream in reasonable time frames.

We focus our exploration program on three strategic play types:

- deep-water prospects near existing infrastructure;
- deep-water, Miocene and Lower Tertiary sub-salt plays with the potential to become new core areas; and
- deep-water, Norphlet targets in the Eastern Gulf of Mexico.

The shorter cycle-times for deep-water prospects near infrastructure complement the longer cycle-times for deep-water sub-salt and Norphlet plays. Over the past few years, we have built our resources and capabilities to explore in the

deep water by accumulating a large inventory of deep-water 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 over the next few years.

Our Gulf production and reserves are primarily concentrated in five deep-water and five shallow-water (shelf) areas. Most of the production impacted by the 2008 hurricane season was restored early in 2009, with the exception of Wrigley, which was delayed for a couple of months. The only production that remains shut in is at Green Canyon 6/50/137, where the third-party production facilities were destroyed by the hurricane.

### DEEP WATER

Most of our deep-water production comes from our 30% non-operated Gunnison field, our 100% operated Aspen field, our 50% non-operated Wrigley field, our 25% non-operated Longhorn field and our 30% non-operated Mississippi Canyon 72 field.

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. Our Gunnison

SPAR facility has excess capacity, leaving room for growth from regional exploration and processing of third-party volumes. We achieved payout on Gunnison in December 2005, just two years after first production. We plan to drill two sidetrack wells in 2010 as we look to utilize some of the Gunnison SPAR excess capacity and increase production.

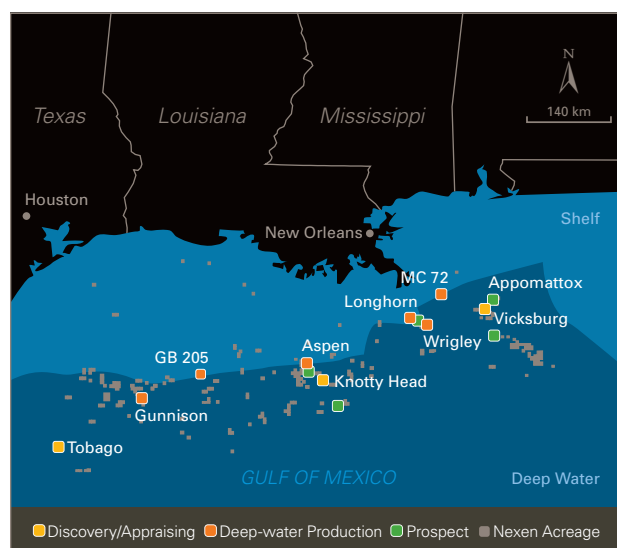
Aspen is on Green Canyon Block 243 in 3,150 feet of water. The project was developed using subsea wells tied back to the Shell-operated Bullwinkle platform 16 miles away and began producing in late 2002. Our share of 2009 production before royalties was approximately 4,300 boe/d (3,900 after royalties).

Wrigley is on Mississippi Canyon Block 506 in 3,300 feet of water. The project consists of a single subsea well tied back to the Shell-operated Cognac platform 17 miles away and began gas production in 2007.

Mississippi Canyon 72 is located in 1,700 feet of water and is a single subsea well tied back to the BP-operated Pompano platform, five miles north of the field. First production was in September 2009.

Our Longhorn property is on Mississippi Canyon Block 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 is approaching peak production of approximately 200 mmcf/d gross (50 mmcf/d, net to us), with higher than expected oil rates. Current production is 37,000 boe/d gross (9,300 boe/d, net to us).

In 2007, we acquired three deep-water producing 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 temporarily suspended as the third-party platform that processed our oil and gas was destroyed by Hurricane Ike in September 2008. We are assessing our options to restore field production, which may include building our own processing platform or potentially divesting the asset.



## SHELF

Our shelf producing assets are offshore Louisiana, primarily in five 100%-owned field areas: Eugene Island 255/257/258/259, Eugene Island 295, Vermilion 320/321/339/340, Vermilion 76 (consisting of Blocks 65, 66 and 67) and West Delta. We continue to look for opportunities to optimize these assets. In 2010, our shelf development program is expected to include up to 12 workovers across four fields to access non-producing proved reserves.

## EXPLORATION AND UNDEVELOPED ASSETS

We hold approximately 205 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
Knotty Head	25	operated	discovery; further appraisal required; currently drilling second well
Vicksburg	25	non-operated	discovery; further appraisal required

During the year, we drilled an unsuccessful exploratory well in deep water at Antietam, about three miles west of our Shiloh discovery. Later in 2009, we began drilling an exploration well at Appomattox, which is approximately six miles west of our Vicksburg discovery. Operations at Appomattox are ongoing and we are currently drilling a sidetrack well to further evaluate the prospect. We have a 20% interest in this well. Elsewhere in 2009, we accepted the first Enco rig and commenced drilling a second appraisal well at Knotty Head. We expect to complete the well and appraise the results in 2010.

In 2010, we expect first production from our Tobago field. We are currently completing the subsea gathering system and the regional host facility, as well as drilling a sidetrack well. Elsewhere in 2010, we plan to drill up to four exploration wells in the deep-water Gulf of Mexico. We are targeting working interests of 25% in these wells and expect to operate three of them. We also expect to take receipt of the second Ensco deep-water drilling rig by mid 2010 to drill several of our exploration prospects.

## FISCAL TERMS

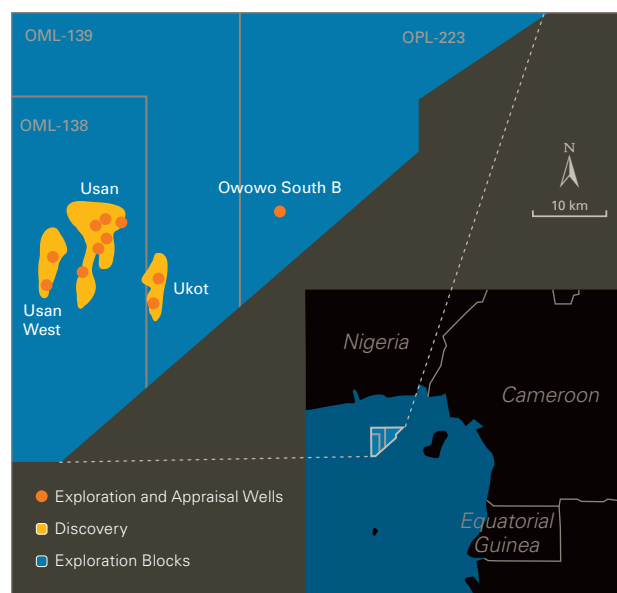
In 2009, royalty rates on our US production averaged 16.3% for shelf volumes and 6.7% for deep-water volumes. The US government increased royalty rates from 12.5 to 16.7% for new deep-water leases awarded after July 2007. Our deep-water Aspen and Gunnison fields are not subject to royalties on the first 87.5 mmbbl of production. US taxable income is subject to federal income tax of 35% and state taxes ranging from 0 to 12%.

## Other International

- The Usan development is currently under construction. We have several discoveries and additional exploration prospects beyond Usan, offshore Nigeria.
- Our entry into Yemen started our international expansion in the early 1990s, which provided us with other significant international opportunities.
- We are leveraging international exploration and operating success with unconventional resource experience to enter new regions.

## Offshore West Africa

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.



## NIGERIA

In 1998, we acquired a 20% non-operated interest in Block OPL-222, which covers 448,000 acres approximately 50 miles 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.

The Nigerian government approved converting OPL-222 into two Oil Mining Leases (OMLs) that will allow the joint venture partners to develop the Usan and Ukot discoveries. OML-138 consists of 50% of the original acreage and includes the Usan discovery. OML-139 consists of the remaining OPL-222 acreage and includes the Ukot discovery.

Development of the Usan field is under way. The field development plan includes an FPSO vessel with a storage capacity of two million barrels of oil. During the year, we progressed the detailed engineering and procurement, commenced development drilling of the field and continued construction of the FPSO hull and subsea facilities. The Usan project is approximately 50% complete. The Usan field is expected to come on stream in 2012, ramping up to peak

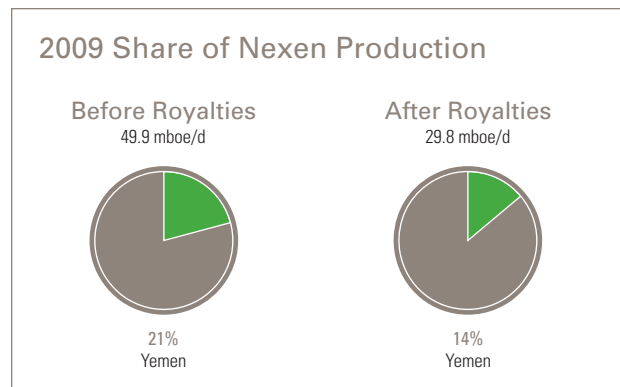
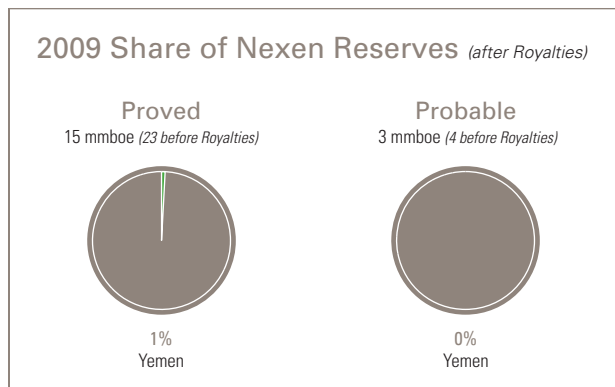
production rates of 180,000 bbls/d (36,000 bbls/d, net to us). We expect that our investment in the Usan development will be approximately \$2 billion (net to us).

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 kilometres northeast of the Usan field. We are analyzing

the drilling results with recently processed new 3-D seismic data to confirm a number of follow-on prospects. 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.

As is typical in many jurisdictions, the Nigerian government is reviewing its existing petroleum fiscal terms, the impact of which is not yet known.

## Middle East—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).



### MASILA BLOCK (BLOCK 14)

We operate the Masila project with a 52% working interest. The Masila fields are mature and the PSA expires at the end of 2011, but significant value still remains.

The first successful Masila exploratory well was drilled at Sunah in 1990, with additional discoveries quickly following at Heijah 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 Shihir export terminal on the Indian Ocean and shipped to customers, primarily in Asia.

Under the Masila 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 2011. We are negotiating a five-year extension but there is no assurance that we will obtain an extension to operate the Masila field and CPF beyond 2011.

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:

<b>Costs</b>	<b>Recovery</b>
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 payable by the Masila Partners at a rate of 35%. In 2009, the Masila Partners' share of production, including recovery of costs, was approximately 45%.

#### **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 a 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 PSA as royalties and taxes consistent with our treatment of our Masila operations. Under the 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:

<b>Costs</b>	<b>Recovery</b>
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 payable by the EAH Partners at a rate of 35%. In 2009, the EAH Partners' share of Block 51 production, including recovery of past costs, was approximately 53%.

#### **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 45 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 production from the field reached 60 million barrels of oil. Our share of 2009 production averaged 3,500 bbls/d before royalties (3,200 after royalties), about 1% of our total production.

In 2009, we acquired two additional exploration blocks in Colombia and now hold five exploration blocks in the Upper Magdalena Basin that we are assessing for future growth opportunities. Production from Guando is subject to a royalty between 5 and 25% depending on daily production. In 2009, the royalty payable to the Colombian government averaged 8%. Colombian taxable income is subject to federal income tax of 33%.

## NORWAY

Norway is an extension of our conventional offshore growth strategy in the North Sea. The Norwegian continental shelf is characterized by well-developed infrastructure and potentially significant hydrocarbon resources. The Norwegian government created incentives for the oil and gas industry to explore this area by providing a 78% cash tax refund on qualifying exploration expenditures to companies that do not yet have a taxable income base.

At December 31, 2009, we hold working interests in nine exploration licences in the Norwegian North Sea. In 2009, we acquired almost 1,500 km<sup>2</sup> of 3-D seismic and 250 km<sup>2</sup> of 2-D seismic. We are optimizing and adding to our portfolio through participation in annual bid rounds and through farm-ins. In 2010, we expect to participate in the Norwegian government licensing rounds and further mature our existing prospects.

Norwegian oil and gas activities are subject to a general corporate income tax rate of 28% plus an additional 50% special petroleum tax.

## UNCONVENTIONAL GAS

As part of our growth strategy in unconventional Canadian resource plays, we have 199 net sections of undeveloped land in an emerging Devonian shale gas play in the Horn River Basin in northeast British Columbia. Shale gas is natural gas produced from reservoirs composed of organic shale. The gas is stored in pore spaces, fractures or absorbed into organic matter. Currently, the United States is the largest producer of shale gas. In this Form 10-K, our shale gas operations in northeast British Columbia are reported with our conventional operations in Canada.

Shale gas complements our corporate oil and gas portfolio, which consists predominantly of large-scale, capital-intensive, long cycle-time projects. It provides natural gas exposure and relatively short cycle-time projects, where we control the scale and pace of development of the resource. In addition, the time required to evaluate drilling and testing results is relatively short. Once our commercial well design is established, we can match the pace of drilling to prevailing economic conditions.

The Horn River Basin is a significant shale gas play in North America with high resource density and excellent well productivity. We have approximately 90,000 acres in the Dilly Creek area and 38,000 acres in the Cordova area in northeast British Columbia, with a 100% working interest in each. To date, we have invested approximately \$480 million in land, infrastructure and wells in the Horn River Basin to progress our shale gas strategy toward development and reserve recognition. We have recognized minimal reserves as we are investing primarily to gain understanding of the optimal commercial development and the resource characteristics.

We have drilled eight horizontal wells with six wells completed to date. Initial production test results are meeting expectations in terms of resource, initial production and decline profile. With five shale gas wells on stream at various times, we reached production of over 15 mmcf/d during the year before declining as expected. Our land position here could support between 500 and 700 wells. Substantial cost savings and productivity improvements were realized in our 2009 drilling and completion program. We took advantage of learnings from prior activities to improve equipment utilization, drill longer wells and initiate more fracs per well. All 26 fracs put into the last three wells were successful.

Primary tenure in the Horn River Basin is four years and drilling activity and extensions increase this up to 18 years. Our drilling activity to date has allowed us to secure tenure for 10 more years on the majority of our Dilly Creek lands. Only two more wells are required to secure the remainder. With tenure secured, we have the ability to slow the pace of drilling during periods of low gas prices.

In 2010, we plan to continue our drilling, completions and fracing program, expand infield facilities and start investing in long-term infrastructure. We will continue to build on our success, which we expect will lead to further cost savings and productivity improvements. In late 2009, we began work on an eight-well test program, which is expected to start providing results and production in late 2010. The Horn River Basin is an early-stage potential shale gas play that has not been developed on a commercial scale. Many of our peers are also working to develop the future potential of the area.

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 early development programs, we have contracted gas pipeline capacity of 96 mmcf/d and associated treating capacity at the Spectra-operated Fort Nelson plant. We entered into additional agreements that will allow us to participate in projects that are expanding infrastructure in the region.

## FISCAL TERMS

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

## RESERVES, PRODUCTION AND RELATED INFORMATION

In addition to the information below, we refer you to the Supplementary Data in Item 8 of this Form 10-K for information on our oil and gas producing activities. Nexen has not filed with nor included in reports to any other United States federal authority or agency any estimates of its total proved oil or gas reserves since the beginning of the last fiscal year.

### 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 29 for a description of probable reserves and our process for estimating proved and probable reserves.

On December 31, 2008, the SEC issued final revised rules relating to reserve definitions and related disclosure requirements. These new rules are effective for estimates and disclosures made on or after January 1, 2010. The primary impacts of the changes on our reserves estimates resulting from the adoption of the new rules are discussed on page 5 of this Form 10-K.

At December 31, 2009, under the new SEC rules, we had 1,011 mmboe of proved reserves (920 after royalties) and 1,217 mmboe of probable reserves (1,057 after royalties). Under the old rules and including Syncrude, we would have had 1,082 mmboe of proved reserves (1,003 after royalties) and 1,397 mmboe of probable reserves (1,215 after royalties) at December 31, 2009.

The following is a summary of our proved and probable reserves as at December 31, 2009 under the new SEC rules:

	Reserves					
	Before Royalties			After Royalties		
	Synthetic Oil <i>(mmbbl)</i>	Oil <i>(mmbbl)</i>	Gas <i>(bcf)</i>	Synthetic Oil <i>(mmbbl)</i>	Oil <i>(mmbbl)</i>	Gas <i>(bcf)</i>
Developed	265	219	418	240	203	379
Undeveloped	377	75	35	339	69	32
<b>Total Proved</b>	<b>642</b>	<b>294</b>	<b>453</b>	<b>579</b>	<b>272</b>	<b>411</b>
Developed	39	115	176	36	110	158
Undeveloped	895	127	71	759	114	68
<b>Total Probable</b>	<b>934</b>	<b>242</b>	<b>247</b>	<b>795</b>	<b>224</b>	<b>226</b>

## PROVED RESERVES

In 2009, before adjusting for the new SEC rules, we added 184 mmboe of proved reserves (155 after royalties) and produced 90 mmboe (78 after royalties). Under the new SEC rules, we added 166 mmboe of proved reserves (123 after royalties) during the year and reduced our bitumen reserves by 53 mmboe (51 after royalties) to reflect the impact of converting from bitumen to synthetic oil barrels on our December 31, 2008 Long Lake reserves estimates. The significant difference in the respective royalty rates reflects the impact of higher oil prices on oil sands royalties in 2009.

The following table provides a summary of the changes in our proved oil and gas reserves before royalties during 2009, including the impact of the adoption of the new SEC rules. Refer to pages 152 to 153 for proved reserves information on an after-royalties basis.

<i>(mmboe)</i>	Canada				United Kingdom	United States	Yemen	Other	Total
	Syncrude	Long Lake Insitu	Other						
December 31, 2008	324	285	90		175	49	31	34	988
Extension and discoveries	7	25	4		20	3	–	8	67
Revisions—technical	–	(4)	1		5	2	11	–	15
Revisions—economic	–	–	–		9	4	1	2	16
Acquisitions	–	86	–		–	–	–	–	86
Divestments	–	–	–		–	–	–	–	–
Production	(7)	(3)	(14)		(37)	(8)	(20)	(1)	(90)
	324	389	81		172	50	23	43	1,082
SEC Rule Transition									
Synthetic—current year	–	(18)	–		–	–	–	–	(18)
Synthetic—prior years	–	(53)	–		–	–	–	–	(53)
<b>December 31, 2009</b>	<b>324</b>	<b>318</b>	<b>81</b>		<b>172</b>	<b>50</b>	<b>23</b>	<b>43</b>	<b>1,011</b>

Extensions and discoveries of 67 mmboe (63 after royalties) relate primarily to ongoing Long Lake reservoir delineation and development drilling at Buzzard, Usan and Telford.

Technical revisions of 15 mmboe (9 after royalties) relate primarily to positive production performance and production optimization activities in Yemen and continued analysis of the proved area at Long Lake, partially offset by a reduction of reserves at Long Lake to reflect lease set-back agreements.

Positive economic revisions of 16 mmboe (negative 2 after royalties) reflect the differences between the oil and gas prices on December 31, 2008 and the average prices in 2009 and differences in costs. Higher oil prices, particularly for heavy oil, resulted in positive economic revisions of 31 mmboe (11 after royalties). Approximately half of these positive economic revisions occurred in our Canadian heavy oil properties, with the rest in other areas such as Buzzard and the Gulf of Mexico. During 2009, gas prices continued to decline and reached an eight-year low. Our gas properties had negative economic revisions of 15 mmboe (13 after

royalties), with 75% occurring in our Canadian conventional gas properties and the remainder in our Canadian CBM properties. The positive economic revision before royalties became negative after royalties due to increased oil sands royalties related to higher oil prices.

The acquisition occurred at Long Lake, where we acquired an additional 15% working interest from our partner early in the year.

The SEC Rule Transition represents changes in reserves quantities resulting from implementing the new SEC rules on the December 31, 2009 quantities. The revision relates to our oil sands reserves at Long Lake, where we produce bitumen and upgrade it to a Premium Synthetic Crude™ in the field. As part of the process, we remove the asphaltenes from the bitumen and use it as our internal fuel source in the steam generation, upgrading and cogeneration power processes. This results in a reduction in the quantity of reserves available for sale; however, these synthetic barrels are expected to have a higher value over the long term.

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 152 to 153 for proved reserves information on an after-royalty basis for each of the past three years.

(mmboe)	Canada							Total
	Syncrude	Long Lake Insitu	Other	United Kingdom	United States	Yemen	Other	
December 31, 2006	324	246	118	182	73	66	40	1,049
Extension and discoveries	23	44	20	35	8	3	8	141
Revisions—technical	–	18	7	63	(8)	23	–	103
Revisions—economic	–	–	(23)	(4)	(4)	1	–	(30)
Acquisitions	–	86	–	1	11	–	–	98
Divestments	–	–	–	–	(2)	–	–	(2)
Production	(23)	(5)	(41)	(105)	(28)	(70)	(5)	(277)
	324	389	81	172	50	23	43	1,082
SEC Rule Transition								
Synthetic—current year	–	(18)	–	–	–	–	–	(18)
Synthetic—prior years	–	(53)	–	–	–	–	–	(53)
<b>December 31, 2009</b>	<b>324</b>	<b>318</b>	<b>81</b>	<b>172</b>	<b>50</b>	<b>23</b>	<b>43</b>	<b>1,011</b>

Since 2006, we added 312 mmboe (326 after royalties), sold 2 mmboe (2 after royalties) and produced 277 mmboe (233 after royalties). Extensions and discoveries of 141 mmboe (132 after royalties) occurred primarily at Long Lake, Syncrude, Buzzard, Canadian CBM and the deep-water Gulf of Mexico. The technical revisions of 103 mmboe (89 after royalties) include 63 mmboe (63 after royalties) of positive revisions in the UK related to better production performance at Buzzard, 23 mmboe (11 after royalties) from better than expected production performance at Yemen and ongoing analysis of the reservoir at Long Lake. Negative technical revisions occurred primarily from lower than expected production performance from various deep-water and shelf properties in the US Gulf of Mexico. Negative economic revisions of 30 mmboe (positive 10 after royalties) are primarily related to changes in prices and costs, primarily in our gas areas in Canada and the US, and to a lesser extent at our Canadian heavy oil properties. The positive economic revision after royalties reflects the change in royalty regulations for oil sands projects, which make them oil-price sensitive and causes them to be lower at the prices used in the reserves estimates.

## PROVED DEVELOPED AND UNDEVELOPED RESERVES

The following table provides proved undeveloped reserves (PUDs) before royalties at December 31, 2009 and the changes during 2009. We have included Syncrude in the table and presented a portion of the previously reported mining reserves as PUDs at December 31, 2008 as if it was always an oil and gas activity. We believe this allows for better presentation of the changes during 2009.

(mmboe)	Canada							Total
	Syncrude	Long Lake Insitu	Other	United Kingdom	United States	Yemen	Other	
December 31, 2008	105	232	4	40	11	3	28	423
Extension and discoveries	11	25	1	–	–	–	8	45
Revisions	–	(4)	(2)	–	1	(1)	2	(4)
Conversions	–	(4)	–	(12)	(1)	(1)	–	(18)
Acquisitions	–	70	–	–	–	–	–	70
	116	319	3	28	11	1	38	516
SEC Rule Transition								
Synthetic—current year	–	(16)	–	–	–	–	–	(16)
Synthetic—prior years	–	(42)	–	–	–	–	–	(42)
<b>December 31, 2009</b>	<b>116</b>	<b>261</b>	<b>3</b>	<b>28</b>	<b>11</b>	<b>1</b>	<b>38</b>	<b>458</b>
PUD % <sup>1</sup>	36%	82%	3%	16%	23%	4%	88%	45%

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

In 2009, our PUDs increased by 35 mmbœ (7 after royalties). Extensions and discoveries of 45 mmbœ (41 after royalties) relate to the ongoing Long Lake reservoir delineation and the addition of another year of production at Syncrude, which will come from an undeveloped mine. We had negative revisions of 4 mmbœ (15 after royalties) primarily at Long Lake due to lease set-back agreements, and in our Canadian and US gas areas, where low gas prices have made developments at average 2009 prices uneconomic. After-royalty changes reflect the impact of higher price-sensitive royalties from our oil sands properties at Long Lake and Syncrude. We converted 18 mmbœ (18 after royalties) with the start-up of our Ettrick field in the UK North Sea, the drilling of an additional SAGD well pad at Long Lake and ongoing development of various other properties.

At Syncrude, PUDs of 116 mmbœ (103 after royalties) relate to a new mine that will be required to provide bitumen feedstock to the upgrading facility. The mine is part of the Syncrude development plan and was contemplated in conjunction with 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 field construction in 2012.

At Long Lake, PUDs of 261 mmbœ (236 after royalties) relate to ongoing drilling to offset declines from the initial SAGD wells. They are expected to be converted to developed over the next 27 years as we drill additional wells to provide bitumen feedstock to run the upgrader at capacity. These wells were part of the field development plan and were included in the project investment decision.

In the United Kingdom, about 90% of the 28 mmbœ (28 after royalties) relate to Buzzard while the remainder relate to Ettrick. The Buzzard PUDs are expected to be converted to proved over the next few years with the expected completion of the addition of the H<sub>2</sub>S handling facilities in 2010 and as we drill additional development wells. We expect to convert the majority of Ettrick PUDs to producing within a year.

In our other international countries, PUDs of 38 mmbœ (33 after royalties) relate primarily to offshore West Africa.

Excluding Long Lake, we expect to convert over 90% of our PUDs to producing in the next four years. Long Lake PUDs will be converted over the next 27 years as new wells are drilled to offset declines from the initial SAGD wells. We expect our ongoing exploration and development activities to continue to add new PUDs.

During the year, we spent \$625 million on our PUDs. The amount relates to PUDs converted to proved developed reserves in the year and to those that will be converted in future years.

We have reviewed our PUDs and determined there are no material amounts in individual fields that have remained undeveloped for five years or more after they were initially recognized as proved reserves.

Following is a summary of our developed and undeveloped proved oil and gas reserves by country and product at December 31, 2009:

	Before Royalties			After Royalties		
	Synthetic Oil	Oil	Gas	Synthetic Oil	Oil	Gas
	(mmbbl)	(mmbbl)	(bcf)	(mmbbl)	(mmbbl)	(bcf)
Canada	265	35	260	240	29	241
United Kingdom	–	142	13	–	142	13
United States	–	15	145	–	13	125
Yemen	–	22	–	–	14	–
Other Countries	–	5	–	–	5	–
<b>Developed</b>	<b>265</b>	<b>219</b>	<b>418</b>	<b>240</b>	<b>203</b>	<b>379</b>
Canada	377	2	4	339	2	3
United Kingdom	–	27	4	–	27	4
United States	–	7	27	–	6	25
Yemen	–	1	–	–	1	–
Other Countries	–	38	–	–	33	–
<b>Undeveloped</b>	<b>377</b>	<b>75</b>	<b>35</b>	<b>339</b>	<b>69</b>	<b>32</b>
<b>Total Proved</b>	<b>642</b>	<b>294</b>	<b>453</b>	<b>579</b>	<b>272</b>	<b>411</b>

## PROBABLE RESERVES

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but that, together with proved reserves, are as likely as not to be recovered. Therefore, probable reserves have a higher degree of uncertainty than proved reserves. In prior years, information on probable reserves was reported outside of our Form 10-K and was prepared in accordance with Canadian NI 51-101 and the Canadian Oil and Gas Evaluation Handbook standards. We have presented a continuity schedule as if they had been reported in our Form 10-K last year.

At December 31, 2009, we had 1,217 mmboc (1,057 after royalties) of probable oil and gas reserves. During the year, we added 349 mmboc (250 after royalties), representing a 33% (26% after royalties) increase to our estimate the prior year. The conversion of bitumen to PSC™ in accordance with SEC requirements reduced our quantities by 180 mmboc (158 after royalties), of which 41 mmboc (50 after royalties) reflect the current year and the remainder to prior years. The after-royalties reserves estimates did not increase as significantly due to the impact of higher prices. Including the effects of reconciliation to the new SEC rules our probable reserves have increased by 169 mmboc (92 after royalties).

The following provides a summary of the changes in our probable oil and gas reserves before royalties during 2009, including the impact of converting to the new SEC rules.

(mmboe)	Canada							Total
	Syncrude	Long Lake Insitu <sup>2</sup>	Other	United Kingdom	United States	Yemen	Other	
December 31, 2008 <sup>1</sup>	46	732	36	136	24	13	61	1,048
Extension and discoveries	7	152	8	48	3	–	6	224
Revisions—technical	–	(10)	3	5	(2)	(3)	(10)	(17)
Revisions—economic	–	(26)	(5)	(2)	1	1	(2)	(33)
Conversions	(7)	–	(1)	(18)	(2)	(7)	(10)	(45)
Acquisitions	–	220	–	–	–	–	–	220
	46	1,068	41	169	24	4	45	1,397
SEC Rule Conversion								
Synthetic—current year	–	(41)	–	–	–	–	–	(41)
Synthetic—prior years	–	(139)	–	–	–	–	–	(139)
<b>December 31, 2009</b>	<b>46</b>	<b>888</b>	<b>41</b>	<b>169</b>	<b>24</b>	<b>4</b>	<b>45</b>	<b>1,217</b>

1 Information on probable reserves was previously reported outside of our Form 10-K and was prepared in accordance with Canadian NI 51-101 and the Canadian Oil and Gas Evaluation Handbook standards. The estimates at December 31, 2008 and changes during 2009 were prepared under those standards. The conversion to the new SEC rules is shown separately.

2 The insitu oil sands reflect our share of the probable reserves for Phases 1 and 2 at Long Lake.

The following provides a summary of the changes in our probable oil and gas reserves after royalties during 2009, including the impact of converting to the new rules.

(mmboe)	Canada							Total
	Syncrude	Long Lake Insitu <sup>2</sup>	Other	United Kingdom	United States	Yemen	Other	
December 31, 2008 <sup>1</sup>	43	677	31	136	20	8	50	965
Extension and discoveries	7	121	7	48	2	–	5	190
Revisions—technical	–	(9)	3	5	(1)	(1)	(8)	(11)
Revisions—economic	(2)	(80)	(6)	(2)	1	(1)	(3)	(93)
Conversions	(7)	–	–	(18)	(2)	(3)	(9)	(39)
Acquisitions	–	203	–	–	–	–	–	203
	41	912	35	169	20	3	35	1,215
SEC Rule Conversion								
Synthetic—current year	–	(50)	–	–	–	–	–	(50)
Synthetic—prior years	–	(108)	–	–	–	–	–	(108)
<b>December 31, 2009</b>	<b>41</b>	<b>754</b>	<b>35</b>	<b>169</b>	<b>20</b>	<b>3</b>	<b>35</b>	<b>1,057</b>

1 Information on probable reserves was previously reported outside of our Form 10-K and was prepared in accordance with Canadian NI 51-101 and the Canadian Oil and Gas Evaluation Handbook. The estimates at December 31, 2008 and changes during 2009 were prepared under those standards. The conversion to the new SEC rules is shown separately.

2 The insitu oil sands reflect our share of the probable reserves for Phases 1 and 2 at Long Lake.

Extensions and discoveries of 224 mmboe (190 after royalties) relate primarily to ongoing Long Lake reservoir delineation, successful development drilling at Telford and exploration successes in the Golden Eagle area and Rochelle in the UK and at Owowo, offshore West Africa. Negative technical revisions of 17 mmboe (11 after royalties) relate primarily to a reduction at Long Lake to reflect lease set-back agreements. Negative economic revisions of 33 mmboe (93 after royalties) primarily reflect higher oil prices, changes in the economic assumptions at Long Lake Phase 2 and lower gas prices. The larger negative revisions after royalties reflects increased oil sands royalties related to higher oil prices. Conversions reflect probable reserves converted to proved as a result of increased confidence in producing the reserves based on production performance and drilling results. The acquisition reflects the additional working interest acquired in Long Lake Phases 1 and 2.

## 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, 2009:

	Before Royalties			After Royalties		
	Synthetic Oil	Oil	Gas	Synthetic Oil	Oil	Gas
	(mmbbl)	(mmbbl)	(bcf)	(mmbbl)	(mmbbl)	(bcf)
Canada	39	18	75	36	14	69
United Kingdom	–	88	18	–	88	18
United States	–	5	83	–	4	71
Yemen	–	3	–	–	3	–
Other Countries	–	1	–	–	1	–
<b>Developed</b>	<b>39</b>	<b>115</b>	<b>176</b>	<b>36</b>	<b>110</b>	<b>158</b>
Canada	895	10	9	759	8	8
United Kingdom	–	70	46	–	70	46
United States	–	2	16	–	2	14
Yemen	–	1	–	–	–	–
Other Countries	–	44	–	–	34	–
<b>Undeveloped</b>	<b>895</b>	<b>127</b>	<b>71</b>	<b>759</b>	<b>114</b>	<b>68</b>
<b>Total Probable</b>	<b>934</b>	<b>242</b>	<b>247</b>	<b>795</b>	<b>224</b>	<b>226</b>

Developed probable reserves 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.

Approximately 85% of our probable reserves before royalties (84% after royalties) are undeveloped. This reflects the incremental reserves related to the ongoing drilling required to keep the upgrader full for Phase 1 at Long Lake and the reserves related to the expected development of Phase 2 at Long Lake. The remaining undeveloped reserves principally relate to completion of the H<sub>2</sub>S facilities at Buzzard; undeveloped discoveries at the Golden Eagle area and Rochelle in the UK and Usan and Owowo, offshore West Africa; and the extension of the plant life and expected higher future yields at Syncrude.

### 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 they will be economically recoverable. Proved reserves are those quantities of oil and gas that, 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 that, together with proved reserves, are as likely as not to be recovered. Therefore, probable reserves have a higher degree of uncertainty than proved reserves.

Management is responsible for the estimates of oil and gas reserves and for preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements, generally accepted industry practices in the US and the standards of the Canadian Oil and Gas Evaluation Handbook modified to reflect SEC requirements. Our reserve estimates and disclosures may differ from other Canadian issuers who follow Canadian NI 51-101. Significant differences between SEC and Canadian reserve estimates and disclosures are described on page 97 (see Special Note to Canadian Investors).

Reserve estimates for each property are internally prepared at least annually by the property's reservoir engineer and geoscientists. They are reviewed by engineers familiar with the property and by divisional management. An Executive Reserves Committee, including our CEO, CFO and internal qualified reserves evaluator, meets with divisional reserves personnel to review the estimates and any changes from previous estimates.

The internal qualified reserves evaluator (IQRE) is responsible for estimating reserves data and related disclosures. This position, required under Canadian 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 27 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. He provides a report on Canadian NI 51-101 Form F-2 stating that the reserves information has, in all material respects, been prepared and reported in accordance with our reserves standards. This report is included as an exhibit to this Form 10-K.

Our reserves estimates are based on internal analysis. We have at least 80% of our oil and gas reserves either evaluated or audited annually by independent qualified reserves consultants to increase our confidence in our estimates. Given that reserve 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 to reconcile any differences on a proved plus probable basis to be within an acceptable tolerance, and as such, probable reserves for individual properties within the portfolio may differ significantly. The nature and extent of the independent evaluations and audits, and the results thereof, are provided below.

The Board of Directors has a Reserves Review Committee (Reserves Committee) to assist the Board and the Audit 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. It 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 estimated reserves 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 Form 10-K.

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 estimates 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. Generally accepted 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 evaluator or auditor 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 rules.

We engaged DeGolyer and MacNaughton (D&M) to evaluate 100% of our proved and 100% of our proved plus probable reserves for the United Kingdom and Yemen Masila. They also reviewed 100% of our proved and 88% of our proved plus probable reserves for Nigeria. A separate opinion was provided on each of these areas. D&M provided opinions that the proved and proved plus probable reserves for the reviewed properties are reasonable within an acceptable tolerance based upon a detailed evaluation and comparison of their aggregate estimates to ours.

We engaged McDaniel & Associates Consultants Ltd. (McDaniel) to evaluate 98% of our proved and 99% of our proved plus probable reserves for our Canadian conventional, CBM and insitu oil sands properties. They also audited 100% of our proved and proved plus probable reserves for our Syncrude interest. Separate opinions were provided for the evaluation and for the audit. McDaniel provided opinions that the proved and proved plus probable reserves for the reviewed properties are reasonable within an acceptable tolerance based upon a detailed evaluation and comparison of their aggregate estimates to ours.

We engaged Ryder Scott Company (Ryder Scott) to evaluate 93% of our proved and 95% of our proved plus probable US Gulf of Mexico deep-water and shelf properties. Ryder Scott provided an opinion that the proved and proved plus probable reserves for the reviewed properties are reasonable within an acceptable tolerance based upon a detailed evaluation and comparison of their aggregate estimates to ours.

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. The reports are included as exhibits to this Form 10-K.

## Net Sales by Product from Oil and Gas Operations

(Cdn\$ millions)	2009	2008	2007
Conventional Crude Oil and Natural Gas Liquids (NGLs)	3,605	5,534	4,077
Synthetic Crude Oil	480	691	545
Natural Gas	316	652	499
<b>Total</b>	<b>4,401</b>	<b>6,877</b>	<b>5,121</b>

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>		
	2009	2008	2007	2009	2008	2007
<b>Crude Oil and NGLs</b> (Cdn\$/bbl)						
United Kingdom	67.70	96.23	76.30	6.87	6.75	6.94
Canada	53.04	74.51	44.07	20.82	22.16	18.67
Syncrude	70.96	105.47	79.76	39.09	42.04	30.32
United States	65.01	104.94	69.83	14.10	13.48	9.69
Yemen	68.49	99.87	76.29	18.34	15.88	12.00
Other Countries	59.05	98.98	71.29	6.53	4.91	3.76
<b>Natural Gas</b> (Cdn\$/mcf)						
United Kingdom	3.95	6.78	4.71	1.15	1.12	1.16
Canada	3.78	7.73	6.32	1.92	2.09	2.28
United States	4.67	10.07	7.80	2.35	2.25	1.61
<b>Corporate Average</b> (Cdn\$/boe)	<b>60.02</b>	<b>89.78</b>	<b>68.46</b>	<b>13.33</b>	<b>13.18</b>	<b>11.63</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
United Kingdom	220	104	1,303	917	1,523	1,021
Canada	810	625	1,081	683	1,891	1,308
Synthetic	10	6	735	303	745	309
Syncrude	84	6	264	19	348	25
United States	220	125	1,200	592	1,420	717
Yemen <sup>2</sup>	50	29	756	629	806	658
Colombia <sup>4</sup>	1	–	788	611	789	611
Nigeria <sup>2,3</sup>	–	–	678	131	678	131
Norway	–	–	753	426	753	426
<b>Total<sup>5</sup></b>	<b>1,395</b>	<b>895</b>	<b>7,558</b>	<b>4,311</b>	<b>8,953</b>	<b>5,206</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 joint venture agreements.

<sup>4</sup> The acreage is covered by an association contract.

<sup>5</sup> Approximately 25% 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>
United Kingdom	61	29	–	–	61	29
Canada	2,033	1,448	3,087	2,713	5,120	4,161
Synthetic	91	59	21	14	112	73
United States	180	91	208	144	388	235
Yemen	555	336	–	–	555	336
Colombia	112	11	–	–	112	11
<b>Total</b>	<b>3,032</b>	<b>1,974</b>	<b>3,316</b>	<b>2,871</b>	<b>6,348</b>	<b>4,845</b>

<sup>1</sup> Gross wells are the total number of wells in which we own an interest.

<sup>2</sup> Net wells are the sum of fractional interests owned in gross wells.

## Drilling Activity

(number of net wells)	2009						
	Net Exploratory			Net Development			Total
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
United Kingdom	3.1	1.3	4.4	5.7	0.8	6.5	10.9
Canada	8.1	–	8.1	50.3	–	50.3	58.4
Synthetic <sup>1</sup>	–	–	–	6.5	–	6.5	6.5
United States	0.7	0.2	0.9	1.0	–	1.0	1.9
Yemen	–	–	–	12.4	–	12.4	12.4
Nigeria	0.2	–	0.2	1.6	–	1.6	1.8
<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	
United Kingdom	2.5	2.0	4.5	3.3	–	3.3	7.8
Canada	9.2	–	9.2	216.4	–	216.4	225.6
Synthetic <sup>1</sup>	–	–	–	–	–	–	–
United States	0.5	1.0	1.5	1.3	–	1.3	2.8
Yemen	–	1.0	1.0	17.4	–	17.4	18.4
Colombia	–	–	–	1.6	–	1.6	1.6
<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>

(number of net wells)	2007						
	Net Exploratory			Net Development			Total
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
United Kingdom	2.0	3.2	5.2	4.2	–	4.2	9.4
Canada	23.2	0.6	23.8	295.6	3.2	298.8	322.6
Synthetic <sup>1</sup>	–	–	–	–	–	–	–
United States	0.8	2.9	3.7	8.6	1.0	9.6	13.3
Yemen	1.0	1.0	2.0	28.0	–	28.0	30.0
Colombia	–	0.9	0.9	7.0	–	7.0	7.9
<b>Total</b>	<b>27.0</b>	<b>8.6</b>	<b>35.6</b>	<b>343.4</b>	<b>4.2</b>	<b>347.6</b>	<b>383.2</b>

<sup>1</sup> Synthetic productive development wells are SAGD producer and injector wells pairs. In addition to these wells, we have drilled a further 34.8 net wells during 2009 (2008—88.5 net wells; 2007—105.0 net wells).

## Wells in Progress

At December 31, 2009, we were drilling two wells in the United Kingdom (1.1 net), one well in Canada (1.0 net), two wells in the United States (0.5 net), one well in Yemen (0.5 net), two wells in Nigeria (0.4 net) and one well in Norway (0.5 net). There were no wells drilling in Colombia at December 31, 2009.

## ENERGY MARKETING

Our energy marketing group currently sells proprietary and third-party natural gas, crude oil, natural gas liquids and power in certain regional global markets. We use financial and derivative contracts, including futures, forwards, swaps and options for hedging purposes.

Our marketing strategy is to:

- obtain competitive pricing on the sale of our oil and gas production;
- provide market intelligence in support of our oil and gas operations;
- provide superior customer service to producers and consumers;
- capitalize on crude oil market opportunities through physical trading; and
- optimize physical assets or contracts to which we have access.

This strategy aligns with our corporate focus on realizing the full value from our assets and provides us with the market intelligence needed to deliver oil and gas production to market at competitive pricing.

In 2009, we announced that we were reviewing strategic alternatives for our natural gas and power marketing businesses, which may include the sale of all or part of these businesses. At this time, the review is under way and is expected to conclude in 2010.

### North American Crude Oil Marketing

Our crude oil business in North America markets physical crude oil to end-use refiners, as well as buying and selling natural gas liquids (NGLs). The crude oil group markets Nexen's proprietary production and third-party production. Our team leverages regional knowledge, retains capacity on key North American infrastructure and maintains solid customer relationships. In addition to physical marketing, we take advantage of quality, time and location spreads to generate returns.

Our North American operations focus on key regions supported by our offices in Calgary, Houston and Denver. In Western Canada, our producer services group concentrates on purchasing from a diversified supply base, while our commercial team seeks to optimize sales to refiners. At the end of 2009, we had access to 3.0 mmbbls of crude oil storage and, over the course of the year, marketed approximately 852 mmbbls per day.

### North American Gas Marketing

The North American natural gas team focuses on key regional markets where we have a strategic presence, equity production, solid customer relationships, in-depth understanding of the market or established physical assets. We capture regional opportunities by managing supply, transportation and storage assets for producers and end users. In addition to the fee-for-service income we realize from managing these assets, we generate further revenue by:

- capitalizing on differences in prices between locations using our transportation assets;
- offering customized service to our customers that bundle our assets with the commodity;
- utilizing our storage assets where we optimize forward and seasonal pricing differences; and
- leveraging regional knowledge we gain through optimizing our assets.

At the end of 2009, we held 1.5 bcf/d of pipeline capacity, primarily between Western Canada and the eastern US. We also use storage capacity to store normally cheaper summer gas in the ground until the winter heating season arrives. We had access to 32 bcf of natural gas storage facilities at the end of 2009.

### North American Power Marketing

The power team is responsible for optimizing our 50% interest in a 120 MW gas-fired, combined-cycle power generation facility at Balzac, Alberta, as well as our 50% interest in the 70 MW Soderglen wind power operation in southern Alberta. The Balzac facility began operations in 2001 and Soderglen began operations in 2006. We also market the surplus power from the 170 MW cogeneration facility at Long Lake, in which Nexen has a 65% interest, which commenced operations in 2008. We market power to larger commercial, industrial and municipal clients.

## Europe

Our European operations include a UK-based European gas and power marketing business. At the end of 2009, we had access to 0.1 bcf/d transportation capacity and 4.2 bcf of storage capacity. Our European marketing operations also market most of our international crude oil proprietary production.

## Asia

Our international team in Asia continues to focus on the physical marketing of Masila crude oil. In order to meet customer needs, we occasionally market other regional crude qualities. In addition to our own crude, we sell production for our partners and third parties in the Yemen region.

## CHEMICALS

In 2005, we monetized part of our chemicals business through an initial public offering of the Canexus Income Fund. We currently hold a 65.7% interest in our chemicals business and continue to fully consolidate chemicals in our Consolidated Financial Statements.

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.



Electricity is the most significant operating cost in producing sodium chlorate and chlor-alkali products. At the end of December 2009, electricity costs were approximately 40% of total cash costs. Therefore, our facilities are strategically located to take advantage of economic power sources. Our second-highest cost is transportation. The proximity of our manufacturing plants to major customers and competitive freight rates minimize our transportation costs. Labour is also a significant manufacturing cost. Approximately 55% of our workforce is unionized with collective agreements in place at all of our unionized plants.

To grow value in our chemicals business, we focus on reducing our costs while maintaining market share, building a sustainable North American customer base and capturing new offshore opportunities.

## North America

The North American pulp and paper industry consumes approximately 92% of the continent's sodium chlorate production. We market our sodium chlorate production to numerous pulp and paper mills under multi-year contracts that contain price and volume adjustment provisions. Approximately 29% of this production is sold in Canada, 66% in the US, and the rest is marketed offshore.

We are the third largest manufacturer of sodium chlorate in North America, with three Canadian facilities: Nanaimo, British Columbia; Brandon, Manitoba; and Beauharnois, Quebec.

In 2008, we completed an expansion of our Brandon plant, increasing capacity to over 290,000 tonnes per year. Brandon is the world's largest sodium chlorate facility and has one of the lowest cost structures in the industry, significantly enhancing our competitive position in North America.

Our chlor-alkali facility at North Vancouver, British Columbia, manufactures caustic soda, chlorine and muriatic acid. Approximately 70% of our caustic soda is consumed by local pulp and paper mills, with the balance consumed in water treatment, oil and gas industry applications and general chemical industry applications in the region. Approximately 25% of the chlorine that we produced was sold in the region as hydrochloric acid, primarily to oil and gas, mining/metal fabrication and general industry accounts. The balance of our chlorine is sold to various customers in the polyvinyl, chloride, water purification and petrochemicals industries, primarily in the United States. A technology

conversion project is currently under way at the North Vancouver plant that will replace existing diaphragm technology and assets with newer, proven membrane technology that is expected to be more cost-effective and will expand productive capacity by 35%. This project is progressing with committed financing in place through to August 2011. The project is expected to start up in the second quarter of 2010 and should lower our cost structure and solidify our low-cost position in this regional market.

## Average Annual Production Capacity

<i>(short tons)</i>	2009	2008	2007
<b>Sodium Chlorate</b>			
North America	431,900	484,800	450,055
Brazil	68,563	68,563	68,563
<b>Total</b>	<b>500,463</b>	<b>553,363</b>	<b>518,618</b>
<b>Chlor-alkali</b>			
North America	364,500	364,500	364,500
Brazil	109,430	109,430	109,430
<b>Total</b>	<b>473,930</b>	<b>473,930</b>	<b>473,930</b>

## Brazil

We entered Brazil in 1999 by acquiring a sodium chlorate plant and a chlor-alkali plant from Aracruz Celulose S.A. (Aracruz), the leading manufacturer of pulp in Brazil. The majority of the sodium chlorate production is sold to Aracruz under a long-term sales agreement that expires in 2024. Most of the chlorine and about 8% of the sodium chlorate production is sold in the merchant market under short-term contracts. In 2002, we completed an expansion at both facilities to meet Aracruz's growing needs. A 2,000-tonne incremental sodium chlorate expansion project at our Brazil plant was completed in early 2009, with a further 4,400-tonne expansion planned to begin in early 2010. The majority of our electricity needs in Brazil are supplied by a long-term supply contract, which expires in February 2013.

## 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 regulation and legislation are represented, and we monitor the progress of proposed legislation and regulatory amendments.

Laws and regulations change frequently and sometimes unpredictably and we are unable to predict the future costs or impact of compliance. However, we do not expect that any of these laws and regulations will affect our operations materially different than they would 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 regulation that affect our business most significantly fall into two categories: i) Operational and ii) Health, Safety and Environment.

### OPERATIONAL REGULATIONS

Our oil and gas exploration and production activities are subject to various federal, state, provincial, territorial, local and international 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.

### HEALTH, SAFETY AND ENVIRONMENTAL REGULATIONS

Our oil, gas and chemical operations are subject to various federal, state, provincial, territorial, local and international 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. 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 management system, 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 Responsibilities and Climate Change

A growing awareness of possible causes and effects of climate change has increased concern over ways the world produces and consumes energy. Government and investor expectations continue to converge on sustainable resource development and responsible operating practices, including the preservation of air, water and land. Some jurisdictions in which we operate have already formalized these expectations into regulation while others move closer to doing so. Regardless of how the jurisdictions in which we operate ultimately define their emissions regulation, we expect that our regulatory obligations and the associated cost of compliance will increase. Due to the uncertainty surrounding the future implementation of emissions regulations, we are unable to estimate our costs of compliance in the future.

As a result of our commitment to sustainable development and responsible operating practices, we believe we are well positioned to meet the challenges of environmental regulation and climate change. 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.

## Air

Canada has signed the Copenhagen Accord (Accord), which should allow Canada to set a new base year and further achieve alignment with the United States. The Accord aims to cut emissions so as to maintain projected world temperature increases at less than 2°C. Specific greenhouse gas (GHG) targets are not stipulated; however, developed nations were required to submit targets for 2020 by January 31, 2010. A commitment was made to raise US\$30 billion over three years beginning in 2010 and US\$100 billion annually starting in 2020 to fund climate change mitigation and adaptation measures in the developing world. The Accord does not include compliance mechanisms, and it remains to be seen whether this agreement will become legally binding on participating nations.

Notwithstanding the Accord, obligations under the Kyoto Protocol remain in place. The Kyoto Protocol came into force in 2005 and was ratified by Canada in December 2002. Kyoto provides for a cap-and-trade system, which requires participating nations to reduce GHG emissions. Canada committed to an emission reduction of 6% below 1990 levels during the First Commitment period from 2008 to 2012. True-up to Kyoto commitments will not take place until sometime later in 2014.

The Canadian federal government has yet to pass climate change legislation. In 2007, the Canadian federal government introduced a paper titled *Regulatory Framework for Air Emissions*, which proposed that the federal government regulate GHGs and air pollutants beginning as early as 2010, with progressively more stringent reductions applied through 2050. Draft regulations have yet to be released. The federal government's recent announcements respecting a Clean Energy Dialogue with the United States and its expressed interest in pursuing a bi-lateral cap-and-trade system with the United States have created further uncertainty about the implementation of the *Regulatory Framework for Air Emissions*.

In June 2009, the Canadian federal government introduced the *Offset System for Greenhouse Gases*. Under this program, the Government of Canada will issue offset credits for GHG emission reductions. Companies that are subject to GHG regulations will be able to purchase these credits in order to comply with regulated targets. Final versions of the offset system guidelines have yet to be published.

The Canadian federal government also indicated its intent to regulate air pollutants concurrent with GHGs, but its schedule and long-term objectives remain unclear. In recent months, work has progressed on a federal *Comprehensive Air Management System*. One of the key features of this system is implementing minimum emission standards for new and existing equipment. We could face technical challenges in meeting these minimum emission standards for certain pollutants. Any required reductions in the 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 2009, 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 emission reductions (a one-time from base, 12% reduction in carbon intensity) on facilities emitting more than 100 kilo-tonnes of CO<sub>2</sub> equivalent. Facilities unable to achieve internal reductions have 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 CO<sub>2</sub> in 2008 and will increase \$5 per year until it reaches \$30 per tonne.

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 2012. Under the ETS, member states are required to establish a national allocation plan approved by the EU. The system only covers CO<sub>2</sub> from some combustion and flaring activities, and member states are allowed to manage allocation across their industrial base as they see fit. Installations have the option of purchasing allowances from other participants in order to meet the cap.

Several regulatory initiatives have recently been introduced in the United States. The proposed bills contemplate an economy-wide cap-and-trade regime to reduce GHG creation. Based on comments by the Canadian government, we anticipate that any Canadian climate change regulations will be closely modeled on the United States scheme in both timing and substance. The US Environmental Protection Agency (EPA) has announced its findings that GHGs pose a threat to public health. This finding may lead to further regulations by the EPA under the *Clean Air Act*. It is unclear if and when these legislative proposals will be passed. To meet our current greenhouse gas (GHG) emissions obligations, we adhere to 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, developing water management systems to enhance water tracking and reporting, and seeking water re-use opportunities.

## 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 directly linked to the way in which we manage potential environmental effects and in how we cooperate with local communities, stakeholders, regulators and other industries to reduce the cumulative impact of our projects throughout their lifecycle.

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).

## 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 operational or capital cost of operations, delay requisite permits or approvals from issuing authorities and result in unprofitable or unfavourable operating conditions. During 2009 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, 2009, \$1,053 million (\$2,341 million, undiscounted, adjusted for inflation) has been provided in our Consolidated Financial Statements for asset retirement obligations.

## EMPLOYEES

We had 4,594 employees on December 31, 2009, of which 323 were employed under collective bargaining schemes. Information on our executive officers is presented in Item 10 of this report.

## ITEM 1A.

### 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 96 of this Form 10-K.

#### 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. Crude oil and natural gas are commodities that are sensitive to numerous worldwide factors, many of that are beyond our control, and are generally sold at contract or posted prices. Historically, these prices have been very volatile and are likely to remain volatile in the future. A shortage of crude oil in 2007 and early 2008 drove oil prices to record highs. Recent worldwide economic conditions depressed demand for commodities and caused commodity prices to weaken significantly in late 2008 and early 2009. These swings in prices significantly affected our results of operations and revenue generated from our oil and gas producing assets. Periods of lower commodity prices may reduce our level of spending for oil and gas exploration and development and materially and adversely affect our results of operations.

Crude oil prices we receive are based on various reference prices, which generally track the movement of Brent and WTI. Adjustments are made to the reference price to reflect quality differentials and transportation costs. Brent, WTI and other international reference prices are affected by numerous and complex worldwide factors such as supply

and demand fundamentals, economic outlooks, production quotas set by the Organization of Petroleum Exporting Countries and geopolitical events.

#### Weak global economic activity and fragile credit markets may negatively impact our liquidity.

While we generally rely upon cash flow from operations to fund our activities, a sustained reduction in the prices of crude oil and natural gas may require us to rely upon existing credit facilities or issue new debt or equity to satisfy our funding needs. The most recent economic crisis resulted in a tightening of the credit markets, a lower level of liquidity in many financial markets and volatility in worldwide fixed income, credit, currency and equity markets. There could be follow-on effects as a result of the credit crisis on our business, which could negatively impact our liquidity and operations, and which may materially affect our business, including a reduced ability to access credit markets or issue new public or private debt, higher borrowing costs, lower returns on invested cash and a negative change to our ratings outlook or a reduction of our credit ratings by one or more credit-rating agencies. A credit-rating downgrade could limit our access to private and public credit markets and increase the costs of borrowing under existing facilities. In addition, if our credit ratings were downgraded, we could be required to provide additional liquidity to support our energy marketing division as further collateral may be required by our counterparties, or we may also be required to reduce some of our energy marketing activities.

#### 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. The recent credit crisis in 2008 and 2009 that impacted world financial

markets and depressed oil and gas prices caused some of our counterparties to restructure, declare bankruptcy or sell assets to fund liquidity requirements. We incurred some losses in 2008 from counterparties facing such difficulties, as described in our financial statements. In the future, we may experience similar losses. Most of our receivables and partners are with counterparties in the energy industry and are subject to normal industry credit risk. The inability of any one or more of these parties to fulfill their obligations to us may adversely impact our results of operations.

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

Our oil, gas and chemical operations are subject to various federal, state, provincial, territorial, local and international 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 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); and
- the issuance of permits and other regulatory approvals in connection with exploration, drilling and production activities.

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. 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.

### 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. The pulp and paper chemicals market is also highly competitive. 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.

### Exploration, development and production activities may not be successful and carry a risk of loss.

Acquiring, developing and exploring for oil and natural gas involve 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. 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 canceled as a result of a variety of factors, including:

- encountering unexpected formations or pressures;
- blow-outs, well bore 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.

We may not achieve production targets should our reservoir production decline sooner than expected. Also, we operate two facilities that are located in close proximity to populated areas, and each processes materials of potential harm to the local populations. We may not be fully insured against all of these risks. 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 Canadian gas resource plays, such as CBM and shale gas. Exploitation techniques and practices for these resources in Canada generally remain 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.

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.

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 and lower producing rates, and reserves per well than conventional gas wells, although this varies by area;
- 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;
- 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.

### Our heavy oil production is more expensive and yields lower prices than light oil.

Heavy oil is characterized by high specific gravity or weight and high viscosity or resistance to flow. Because of these features, heavy oil is more difficult and expensive to extract, transport and refine than other types of oil. Heavy oil typically yields a lower price relative to light oil and gas, as a smaller percentage of high-value petroleum products can be refined from heavy oil. As a result, our heavy oil operations are exposed to the following risks:

- additional costs may be incurred to purchase diluent to transport heavy oil;
- there could be a shortfall in the supply of diluent, which may cause its price to increase; and
- the market for heavy oil is more limited than for light oil, making it more susceptible to supply and demand fundamentals, which may cause the price to decline.

Any one or a combination of these factors could cause some of our heavy oil properties to become uneconomic to produce and/or result in negative reserve revisions.

### 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 flows from operations are 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 impaired.

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.

Under SEC rules, 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. At December 31, 2009, 45% of our proved reserves before royalties (45% after royalties) were undeveloped, largely reflecting oil sands reserves that will be developed as required to keep the related upgrader full.

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

Phase 1 of 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 a sweet, light, Premium Synthetic Crude™ 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.

In addition to the risks associated with heavy oil production stated above, risks associated with our Long Lake project include the following:

#### APPLICATION OF 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 several commercial SAGD projects have been in operation for over seven years.

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, we might have to drill additional wells to maintain optimal production levels, construct additional steam generating capacity, 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 NEW BITUMEN UPGRADING PROCESS

The proprietary OrCrude™ process we are using to upgrade raw bitumen to synthetic crude is the first commercial application of the process, although we have operated it in a 500 bbls/d demonstration plant. Initial upgrader operations began in January 2009. There is no certainty that the commercial upgrader at Long Lake will sustain or achieve the results that are now being seen or forecast. 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 relatively low, reflecting its quality differential;
- the market price for bitumen fluctuates; 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 those we have assumed. This would materially decrease expected earnings from the project and the project may not be profitable under these conditions.

## 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, with 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, gaseous 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 the recovered bitumen 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, operating costs per unit 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 project 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, certain governmental entities and the regional municipality of Wood Buffalo (which includes the city of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, including the lands on which the Long Lake project and most of the other oil sands operations in Alberta are located. Such claims, if successful, could have a significant adverse effect on the Long Lake project and on us.

#### PUBLIC PERCEPTION OF OIL SANDS DEVELOPMENT

Development of the Athabasca oil sands has figured prominently in recent political, media and activist commentary on the subject of climate change and greenhouse gas emissions. Public perceptions of

greenhouse gas emissions and water and land use practices in oil sands developments may directly or indirectly impair 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 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 world market for this crude oil and reduces its price.

These perceptions may also impair our corporate reputation and limit our ability to access land and joint venture opportunities in other jurisdictions throughout the world.

#### 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 and Scott production platforms in the UK North Sea;
- central processing facilities, oil pipelines and 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.

#### 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. The commodity markets in which we trade have experienced unanticipated volatility relative to historical variances in the last 18 months, resulting in unusual and significant pricing changes and

deviations from anticipated seasonal pricing trends and pricing levels. 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 the commodities and financial markets could require us to provide additional liquidity if additional collateral is required to be placed with counterparties, or 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.

### 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.

## ITEM 1B.

### Unresolved Staff Comments

There are no unresolved staff comments with the SEC.

## ITEM 3.

### Legal Proceedings

There are lawsuits and claims pending against Nexen, the ultimate results of which cannot be ascertained at this time. Management is of the opinion that any amounts assessed against us would not have a material adverse effect on our consolidated financial position or results of operations. 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 (EPA), state environmental agencies and certain third parties for certain sites seeking to require investigation and remediation under federal or state environmental statutes. In addition, notices, demands and lawsuits have been received for certain sites related to historical operations and activities in the US for which, 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.

## ITEM 4.

### Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of Nexen's security holders during the fourth quarter of 2009.

# PART II

## ITEM 5.

### Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Nexen's common shares are traded on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE) under the symbol NXY.

On December 31, 2009, there were 1,725 registered holders of common shares and 522,915,843 common shares outstanding. The number of registered holders of common shares is calculated excluding individual participants in securities positions listings. During the year, we made no purchases of our own equity securities.

### Trading Range of Nexen's Common Shares

(\$/share)	TSX (Cdn\$)		NYSE (US\$)	
	High	Low	High	Low
<b>2009</b>				
First Quarter	24.24	14.86	20.61	11.89
Second Quarter	28.54	20.65	26.25	16.33
Third Quarter	25.94	20.70	24.43	18.68
Fourth Quarter	27.31	22.26	26.05	20.66
<b>2008</b>				
First Quarter	34.20	26.00	34.57	25.11
Second Quarter	43.45	29.69	42.71	28.87
Third Quarter	41.47	21.12	40.99	20.56
Fourth Quarter	29.10	13.33	23.99	10.81

## Quarterly Dividends Declared on Common Shares

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

Payment date for dividends was the first day of the next quarter. All dividends paid to holders of common shares in 2009 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 of Canada requires us to deduct a withholding tax from all dividends remitted to non-residents. According to the Canada-US Tax Treaty, we have 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%.

The Investment Canada Act requires that a “non-Canadian”, as defined, file notice with Investment Canada and obtain government approval prior to acquiring control of a Canadian business, as defined. Otherwise, there are no limitations, either under the laws of Canada or in Nexen’s charter on the right of a non-Canadian to hold or vote Nexen’s securities.

The following is a table of securities authorized for issuance under equity compensation plans as of December 31, 2009.

<b>Plan Category</b>	<b>Number of Securities to be Issued on Exercise of Outstanding TOPs</b>	<b>Weighted-Average Exercise Price of Outstanding TOPs</b>	<b>Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans</b>
Equity compensation plans approved by shareholders	23,130,414	\$25/option	26,283,536
Equity compensation plans not approved by shareholders	–	–	
<b>Total</b>	<b>23,130,414</b>	<b>\$25/option</b>	<b>26,283,536</b>

See page 178 for a graph showing the change in a \$100 investment in Nexen common shares over the past five years, compared to the S&P/TSX Composite Index, the S&P/TSX Energy Sector Index and the S&P/TSX Oil & Gas Exploration & Production Index as at December 31, 2009.

On February 3, 2000, at a Special Meeting of Shareholders, a Shareholder Rights Plan was approved. On May 2, 2002, at the Annual General and Special Meeting of Shareholders, an Amended and Restated Shareholder Rights Plan (Plan) was approved. According to the Plan, a right is attached to each present and future outstanding common share, entitling the holder to acquire additional common shares during the term of the right. 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.

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. 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).

## ITEM 6.

### Selected Financial Data

### Five-Year Summary of Selected Financial Data in Accordance with US GAAP

(Cdn\$ millions, except otherwise indicated)

	2009	2008	2007	2006	2005
<b>Oil &amp; Gas Production</b>					
Production before Royalties (mboe/d) <sup>1</sup>	243	250	254	212	242
Production after Royalties (mboe/d) <sup>1</sup>	213	210	207	156	173
<b>Results of Operations</b>					
Revenue					
Oil & Gas <sup>2</sup>	4,447	6,907	5,174	3,656	3,535
Marketing	967	522	926	1,373	864
Chemicals	508	427	447	413	413
Other	(130)	364	(26)	(47)	(193)
Total Revenue	5,792	8,220	6,521	5,395	4,619
Net Income from Continuing Operations	507	1,704	1,012	579	658
Basic Earnings per Common Share from Continuing Operations (\$/share)	0.97	3.24	1.92	1.10	1.26
Diluted Earnings per Common Share from Continuing Operations (\$/share)	0.97	3.20	1.88	1.08	1.23
Net Income	507	1,704	1,012	579	1,110
Basic Earnings per Common Share (\$/share)	0.97	3.24	1.92	1.10	2.13
Diluted Earnings per Common Share (\$/share)	0.97	3.20	1.88	1.08	2.08
<b>Financial Position</b>					
Total Assets	22,781	22,048	17,982	17,079	14,493
Long-Term Debt <sup>3</sup>	7,251	6,578	4,610	4,618	3,630
Equity	7,420	6,998	5,449	4,614	3,961
Capital Investment, including Acquisitions	3,497	3,066	3,401	3,408	2,638
Dividends per Common Share (\$/share) <sup>4</sup>	0.20	0.175	0.10	0.10	0.10
Common Shares Outstanding (thousands) <sup>5</sup>	522,916	519,449	528,305	525,026	522,281

1 In 2005, we sold producing properties in Canada. In early 2007, the Buzzard field came on stream and offset declines from Masila in Yemen.

2 In the third quarter of 2005, we sold Canadian conventional oil and gas properties in Saskatchewan, British Columbia and Alberta, producing 18,300 bbls/d. The results of these operations were shown as discontinued operations.

3 Our North Sea asset acquisition credit facility was repaid in 2005 with proceeds from the issuance of US\$1.04 billion in senior notes in the first quarter and from asset dispositions in the third quarter. Our long-term debt increased in 2006 as a result of our capital investments, primarily at Buzzard and Long Lake. In May 2007, we issued US\$1.5 billion of senior notes with US\$250 million maturing in 10 years and US\$1,250 million maturing in 30

years. In June 2009, we filed a universal base shelf prospectus in the US and Canada allowing us to potentially raise US\$3.5 billion of debt, equity or other hybrid securities, should the need arise. In July 2009, we issued US\$1 billion of senior notes with US\$300 million maturing in 10 years and US\$700 million maturing in 30 years.

4 Quarterly dividends were increased to 5 cents per share in the second quarter of 2008.

5 During the third quarter of 2008, we received approval from the TSX for a Normal Course Issuer Bid that allowed us to repurchase up to a maximum of 52,914,046 common shares for the period of August 6, 2008 to August 5, 2009. In 2008, we repurchased and cancelled 12,136,900 common shares for \$338 million.