12025808

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

Form 6-K

REPORT OF FOREIGN PRIVATE ISSUER PURSUANT TO SECTION 13a-16 OR 15d-16 UNDER THE SECURITIES EXCHANGE ACT OF 1934

For March 21, 2012

Commission File Number 1-6702

NEXEN INC.
(Translation of registrant's name into English)

801 – 7 Avenue S.W.
Calgary, Alberta, Canada T2P 3P7
(Address of principal executive office)

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

Form 20-F ☐ Form 40-F ☑

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

Note: Regulation S-T Rule 101(b)(1) only permits the submission in paper of a Form 6-K if submitted solely to provide an attached annual report to security holders.

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

Note: Regulation S-T Rule 101(b)(7) only permits the submission in paper of a Form 6-K if submitted to furnish a report or other document that the registrant foreign private issuer must furnish and make public under the laws of the jurisdiction in which the registrant is incorporated, domiciled or legally organized (the registrant's "home country"), or under the rules of the home country exchange on which the registrant's securities are traded, as long as the report or other document is not a press release, is not required to be and has not been distributed to the registrant's security holders, and, if discussing a material event, has already been the subject of a Form 6-K submission or other Commission filing on EDGAR.

This Report on Form 6-K incorporates by reference the exhibits attached hereto, which were filed by Nexen Inc. with the Canadian Securities Administrators (the "CSA") on the date specified in the exhibit list.

DOCUMENTS FILED AS PART OF THIS FORM 6-K

See the Exhibit Index to this Form 6-K.

SIGNATURE

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

NEXEN INC.
(Registrant)

Date: March 21, 2012

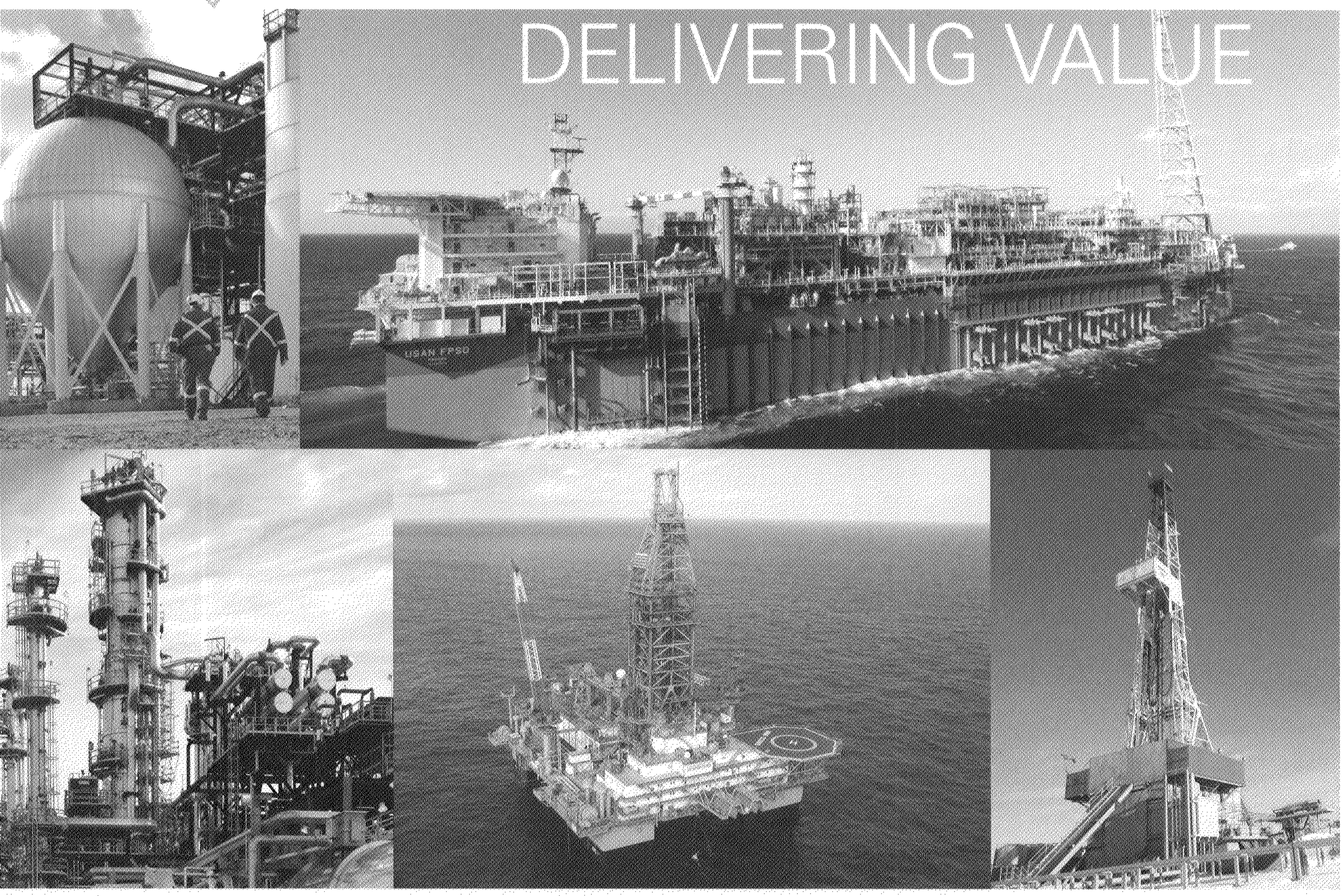
By: ______________________________

Name: Rick C. Beingessner
Title: Assistant Secretary

FORM 6-K EXHIBIT INDEX

Exhibit Number	Description
99.1	The Registrant's Annual Report to Shareholders for the year ended December 31, 2011, as filed with the CSA on March 21, 2012.

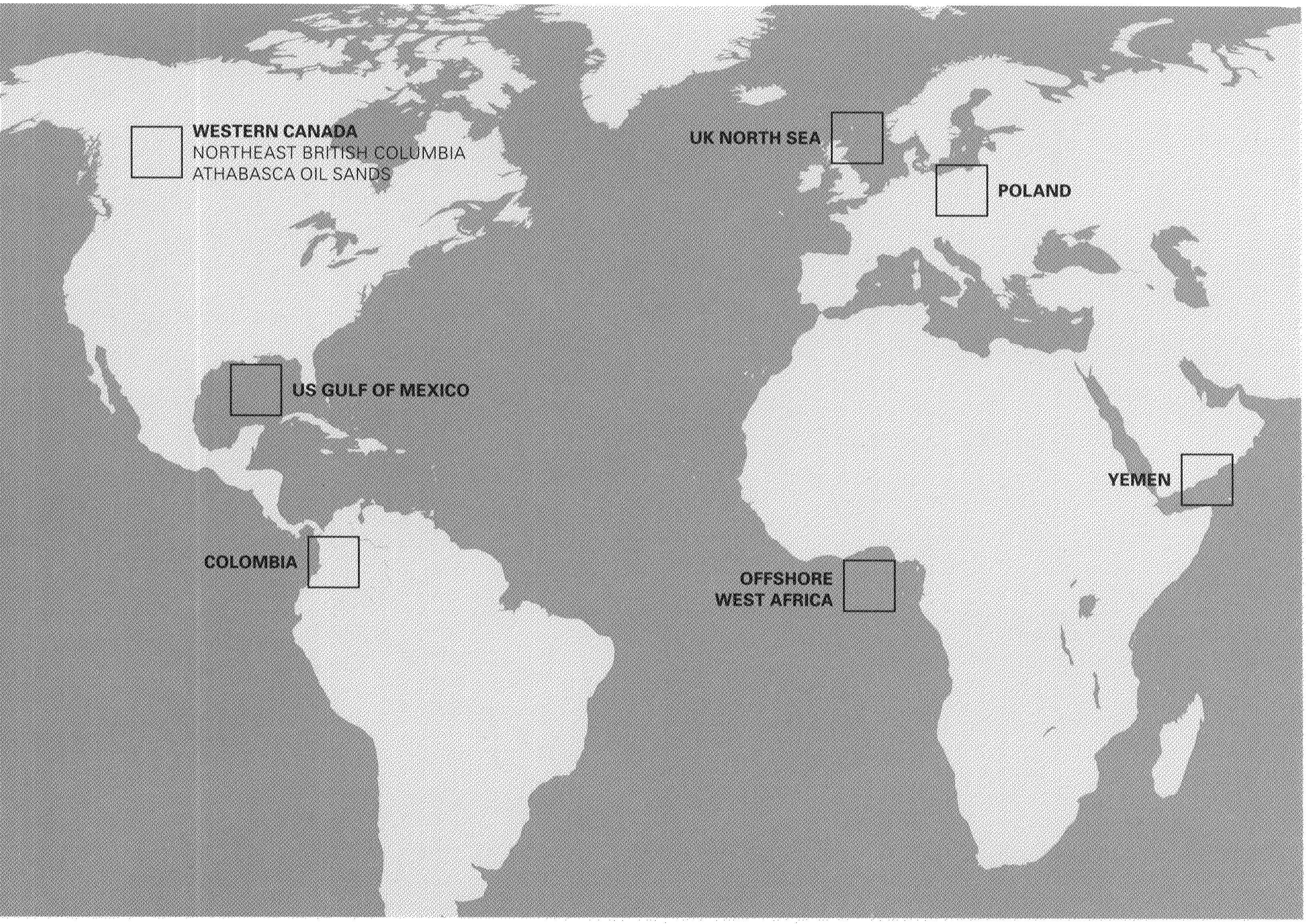
OUR PLAN FOR DELIVERING VALUE



2011 ANNUAL REPORT

nexen

NEXEN'S GLOBAL PORTFOLIO



NEXEN INC. IS A CANADIAN-BASED UPSTREAM OIL AND GAS COMPANY RESPONSIBLY DEVELOPING ENERGY RESOURCES IN SOME OF THE WORLD'S MOST SIGNIFICANT BASINS – INCLUDING WESTERN CANADA, THE UK NORTH SEA, THE GULF OF MEXICO AND OFFSHORE WEST AFRICA.

NEXEN IS STRATEGICALLY FOCUSED ON THREE CORE BUSINESSES: CONVENTIONAL OIL AND GAS, OIL SANDS AND SHALE GAS. WITH A HIGH-QUALITY ASSET BASE AND SIGNIFICANT GROWTH ON THE HORIZON, WE'RE WELL-POSITIONED TO DELIVER LONG-TERM VALUE.

Forward-Looking Statements and Information
This annual report includes forward-looking statements and information that is based on Nexen's current expectations, estimates, projections and assumptions in light of our experience and our perception of historical trends. Actual results may differ materially from those expressed or implied by the forward-looking statements and information. Please see page 20. All amounts are in millions of Canadian dollars unless otherwise stated.

Letter to Shareholders & Performance Review	3
Business Overview	21
Management's Discussion and Analysis	63
Consolidated Financial Statements and Notes	95

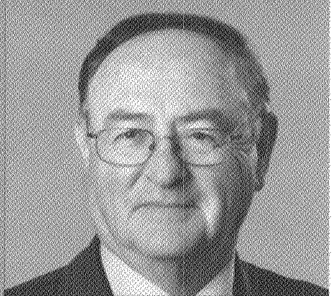
2011: OUR PROGRESS

Being accountable to shareholders means setting clear expectations and reporting our progress along the way. Here's a summary of our 2011 performance against our key priorities.

Our Priorities	Our Progress
Advance growth strategies	• Sanctioned Golden Eagle development in the UK North Sea • Progressed Usan offshore development in West Africa towards on-time start-up • Developed and began implementing action plan to increase Long Lake oil sands production • Resumed drilling in the Gulf of Mexico • Continued to lower supply costs in British Columbia shale gas and began shale gas drilling in Colombia and Poland
Build strategic partnerships	• Secured world-class joint venture partners in the oil sands, British Columbia shale gas and the deep-water Gulf of Mexico
Safety and environment	• Matched our best-ever safety performance. Unfortunately, we had a contractor fatality in a vehicle accident on a British Columbia highway
Achieve production guidance	• UK Buzzard platform production was affected by unplanned maintenance and third-party facility constraints • Long Lake production from wells in good resource quality ramped up as expected but wells in poorer areas did not meet expectations • Production before royalties of 207,000 barrels of oil equivalent per day (boe/d) was below our original 2011 guidance but met our revised guidance
Meet cash flow guidance	• Highest annual cash flow from operations since 2008 due to strong crude oil prices, including a strong weighting to Brent-priced oil
Build financial strength	• Continued non-core asset disposition strategy by selling our stake in Canexus • Reduced net debt by $547 million in 2011

MESSAGE FROM THE CHAIR OF THE BOARD

Francis M. Saville, Q.C.



Francis M. Saville, Q.C.
Chair of the Board

We are committed to creating value through strong execution of Nexen's business strategy.

Over the past year, Nexen's board has taken some decisive steps to position the company for long-term success and value creation. As a result, Nexen is entering an important period of renewal.

As part of our 2011 long range planning, the board conducted a robust strategic review of Nexen's business and explored a full range of options to accelerate value for shareholders. The details of this process are outlined in our management proxy circular. The outcome was clear: the board and our external advisors unanimously concluded Nexen has sound strategies and high-quality assets, and needs to focus on superior execution of those strategies to maximize shareholder value.

We also initiated a search for a new President and CEO to lead Nexen through the next phase of growth. While this search is underway, Kevin Reinhart takes over as interim President and Chief Executive Officer. Kevin and his team are leading a commitment to excellence across the company. Under his leadership, Nexen is placing a sharp focus on accountability and superior operating performance.

My term as board chair ends this spring, however I am pleased to stand for re-election as a member of the board. I want to thank fellow board members, Nexen management and shareholders for their support and contributions over the years.

I also extend my thanks and best wishes to Dennis Flanagan, who is retiring from the board this year.

As I hand over the reins to my successor, I remain very confident about the future of this organization. Nexen is a strong company with significant potential and deep talent. Our board is committed to creating value for our shareholders through strong execution of Nexen's business strategy.

Francis M. Saville, Q.C.
Chair of the Board

2011 Highlights

SUMMARY	2011	2010	2009[1]
Production before Royalties (mboe/d)	**207**	246	243
Production after Royalties (mboe/d)	**186**	220	213
Cash Flow from Operations[2,3] ($ millions)	**2,368**	2,150	2,215
Cash Flow per Share ($/share)	**4.49**	4.10	4.25
Net Income ($ millions)	**697**	1,127	536
Net Income per Share ($/share)	**1.32**	2.15	1.03
Cash Netbacks from Oil and Gas Operations[4] ($/boe)	**40.20**	33.26	38.55
Capital Expenditures ($ millions)	**2,575**	2,724	3,578
Proved Reserves[5] (mmboe)	**1,008**	1,011	1,031
Proved + Probable Reserves[5] (mmboe)	**2,306**	2,134	2,252

1 Financial amounts for 2009 were prepared under previous Canadian Generally Accepted Accounting Principles and have not been restated for IFRS. ***2*** *Defined as cash flow from operating activities before changes in non-cash working capital and other.* ***3*** *For reconciliation of this non-GAAP measure, please see our year-end press release dated February 16, 2012 or our 2011 Management's Discussion and Analysis.* ***4*** *Defined as average sales price less royalties and other, operating costs and in-country taxes.* ***5*** *Represents our working interest before royalties using NI 51-101 regulations. For more information on our reserves, see our 2011 Annual Information Form at www.nexeninc.com or under our profile on www.sedar.com.*

LETTER TO SHAREHOLDERS

Kevin Reinhart, Interim President & CEO

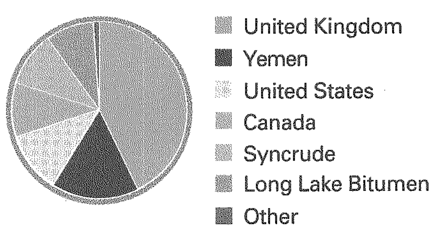
"We achieved many successes in 2011. We also faced some challenges. We tackled those head on and have developed detailed and realistic plans to move Nexen forward.

We are on a clear and exciting path toward unlocking the considerable value in our company. We have the assets, talent and capacity to deliver."

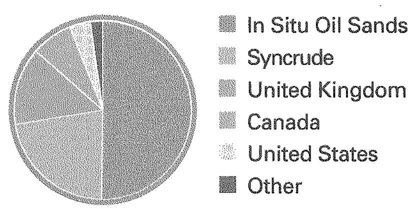
Kevin Reinhart
Interim President
and CEO

(Continued on next page)

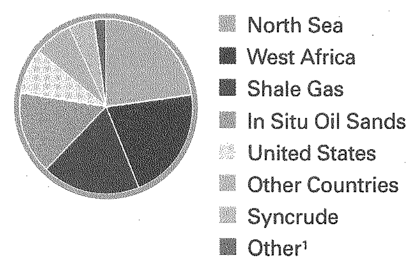
2011 PRODUCTION BEFORE ROYALTIES
207,000 boe/d



2011 PROVED PLUS PROBABLE RESERVES
2.3 billion boe



2011 CAPITAL EXPENDITURES
$2.6 billion

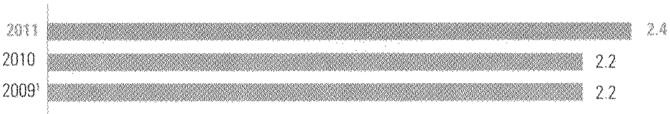


1 Energy Marketing, Corporate and Other.

Nexen has high quality assets and sound strategies. The best way to maximize value is to consistently and capably execute those strategies. This will be our relentless focus in 2012 and beyond.

2011 CASH FLOW
$2.4 billion

(Cdn$ billions)



1 Financial amounts for 2009 were prepared under previous Canadian Generally Accepted Accounting Principles and have not been restated for IFRS.

We formed new and strong partnerships in 2011—a strategic advantage in a global economy.

In the past two years, we have reduced our net debt by 36% and, in 2011, we continued to dispose of non-core assets.

LETTER TO SHAREHOLDERS

I have been appointed as Nexen's interim President and CEO at an exciting and important time.

In 2011, we set the stage for a strong future. We reached a turning point at Long Lake and developed a plan to ramp up production. We advanced our growth plans by sanctioning the Golden Eagle and Rochelle developments in the UK North Sea, resuming drilling in the Gulf of Mexico and moving Usan near to completion. We also continued to execute well in our British Columbia shale gas business.

We formed new and strong partnerships—a strategic advantage in a global economy. In 2011 we announced joint ventures with the China National Offshore Oil Corporation (CNOOC), INPEX Corporation and JGC Corporation—large, well-capitalized companies who support our plans for oil sands, Canadian shale gas and the Gulf of Mexico. I see these as strong endorsements of Nexen's asset base, prospects, talent and capabilities.

We continued to focus on improving our financial strength. Over the past two years, we have reduced our net debt by 36% and in 2011 we continued to add value by disposing of non-core assets. We also added 73 million boe of proved reserves, replacing 96% of our production for the year.

And we did all of this while delivering solid safety and environmental performance and maintaining high standards of integrity and governance.

These achievements reflect many of Nexen's embedded strengths. We have a high-quality portfolio with more than 10 billion barrels of resource[1] in some of the world's best basins. Most of our current production is less than five years old and we have some of the highest netbacks in the industry. Approximately 70% of our oil production attracts Brent pricing, which traded at a significant premium to WTI throughout 2011.

These are solid building blocks for value creation. And we have plans to unlock that value.

Yemen: End of a Chapter

After 25 years of safe, reliable operations in Yemen, our contract with the Yemen government to operate the Masila block ended in late 2011.

Yemen had an extraordinary impact on our company. It exceeded our expectations by producing more than one billion barrels of oil and transformed Nexen into the global company we are today. I am proud of what our employees accomplished there—the relationships we formed, the value we created and the impact we had on the community. Now, we take the expertise we gained on to new opportunities.

Addressing the Challenges

Our 2011 production fell short of our original guidance for the year, primarily due to unplanned maintenance at Buzzard and a slower ramp up at Long Lake. We took corrective action at Buzzard, commissioned a fourth platform and ended the year operating at normal rates.

Our greatest challenge has been at Long Lake, which has not met expectations for ramp up. This has hindered our ability to demonstrate the full value of the asset. Our share price has suffered as a result.

We made significant advances at Long Lake in 2011. We now understand the reservoir quality issues that have slowed our progress. Importantly, we have developed a robust plan to ramp up production to fill the upgrader. Over the next few years, we plan to add 60 more wells, 18 of which are already drilled, in higher-quality reservoir at Long Lake. As production grows, we expect to generate increasingly strong cash flow.

1 See Reserves and Resources note on page 20.

LETTER TO SHAREHOLDERS

A Commitment to Superior Performance

Our 2011 annual strategic review emphasized the importance of consistently executing our strategies and business plans. This will be our relentless focus in 2012 and beyond.

It starts with a renewed commitment to superior delivery and operating performance. To achieve this, we have enhanced our talent in key areas and provided new tools for employees to develop their technical and leadership capabilities. We are implementing operational excellence and reliability programs across our operations. We also have set realistic expectations, and are committed to meeting or exceeding them. If significant barriers arise, we'll communicate them—and our plans to address them—to our shareholders in a timely way.

Our Strategic Priorities

We have outlined our 2012 strategic priorities on the next page. These are the milestones that will help unlock the considerable value in our assets. I know shareholders are looking for consistent delivery of our plan. We will be successful because of our strong fundamentals: an exceptional global asset base, a sound strategy and capable talent. And we will be successful because of our renewed commitment to superior delivery and performance.

As I look to 2012 and beyond, I'm excited about the opportunities before us and I'm confident in the ability of Nexen employees to put our plans into action.

Kevin Reinhart
Interim President and CEO

2012 CAPITAL PLAN
$2.7 billion to $3.2 billion

2012 PRODUCTION

185,000 to
220,000 boe/d

Expected production (before royalties)

2012: STRATEGIC PRIORITIES

We have a plan to unlock the considerable value in our asset base. In 2012, we are focusing on the following:

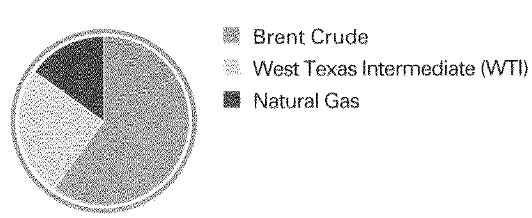
What we plan to do	How we plan to do it
Safe and reliable operations	• Continuously improve safety and environmental results—a foundational element of superior operating performance • Continue to implement operational excellence initiatives across our business with a focus on Buzzard and Long Lake
Implement our oil sands action plan	• Progress drilling of 60 new wells in higher quality reservoir at Long Lake • Bring Long Lake pads 12 and 13 on stream by year end
Advance growth strategies	• Invest \$2.7 billion to \$3.2 billion to advance development projects and production growth from Usan, Long Lake, Rochelle and Golden Eagle • Bring Usan on stream and ramp up production safely • Drill exploration and appraisal wells in high-impact basins where we have significant lease holdings, infrastructure and operating expertise • Make return-driven shale gas investments and examine the potential for liquefied natural gas (LNG) development
Meet production guidance	• Deliver production averaging 185,000 to 220,000 boe/d (before royalties)
Enhance financial strength	• Increase cash flow faster than production as Yemen production is replaced by higher margin barrels from Usan • Reduce debt while maintaining flexibility to invest in the business • Explore options to sell non-core assets

2012 CASH FLOW

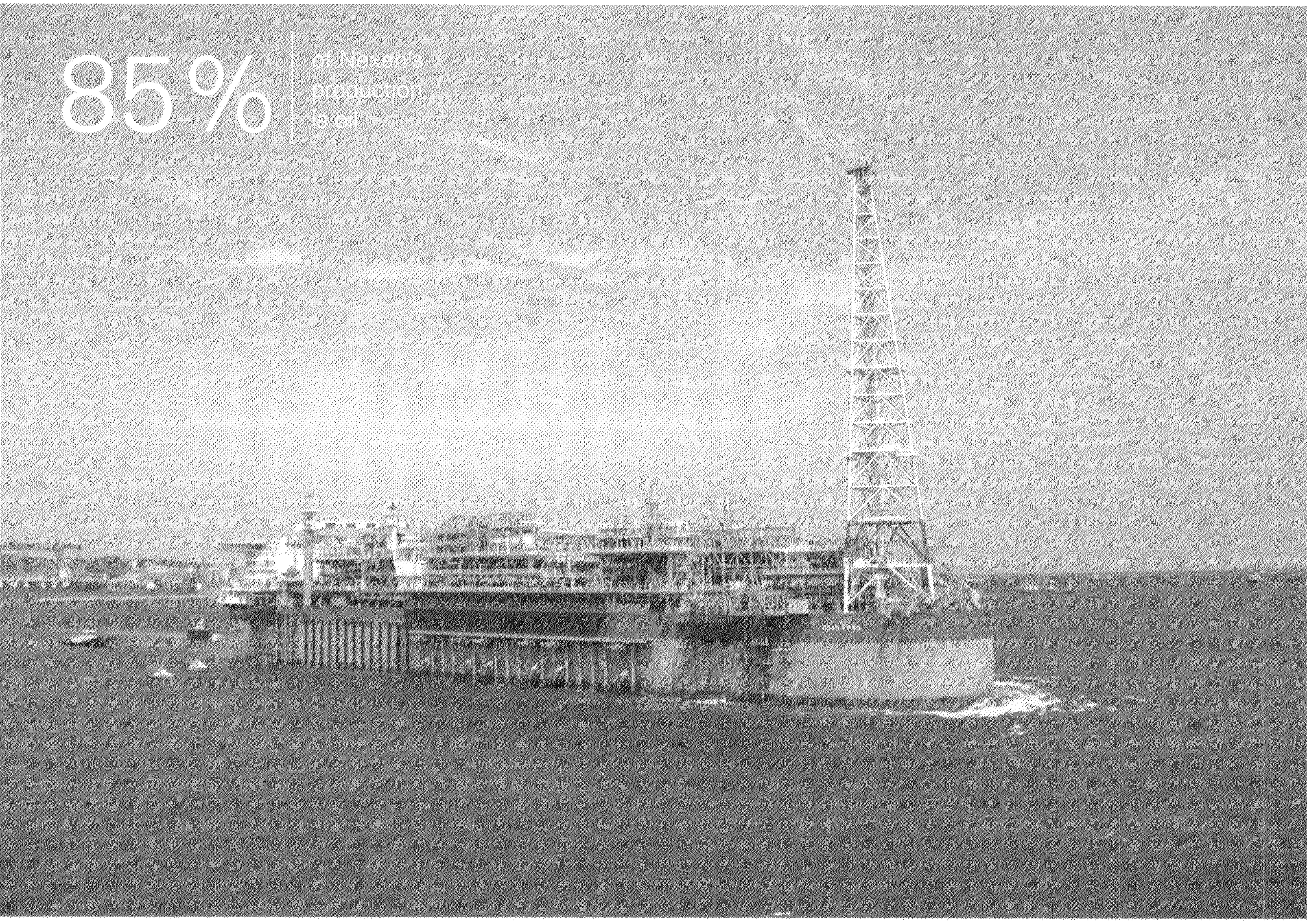
$2.8 to $3.3 billion

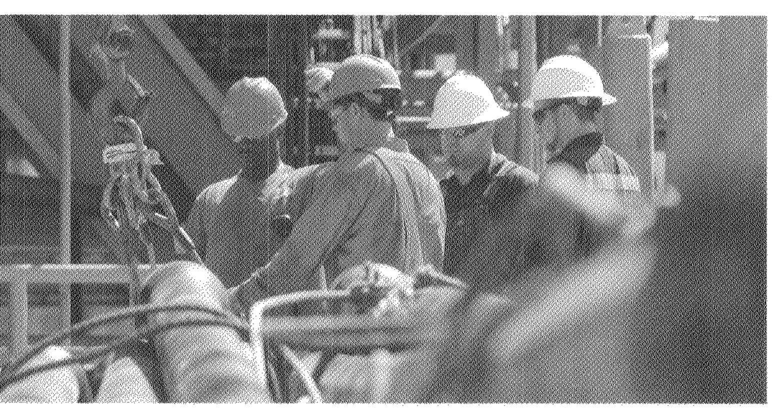
Expected cash flow from operations (at Brent $110/bbl and WTI $95/bbl)

NEXEN'S PORTFOLIO MIX



CONVENTIONAL OIL & GAS





Our exploration success rate over the past five years places us among the top 20% of oil and gas explorers worldwide.

We have several value-generating growth projects underway including the Usan, Rochelle, Golden Eagle, Knotty Head and Appomattox areas.

Our conventional business is comprised of early-life, high-margin assets that form the heart of Nexen's current production and cash flow. And we have plenty of high-quality resource to add even more.

Why Conventional Oil and Gas?

Nexen is exploring and developing in some of the world's most significant conventional basins, including the UK North Sea, offshore West Africa and the deep-water Gulf of Mexico. This business is primarily comprised of early life, high-margin assets that form the heart of Nexen's current production and cash flow, as well as some of our best prospects going forward.

2011 Progress

Buzzard remains one of Nexen's most important assets and we've increased our expected ultimate recovery by about 60% since acquiring Buzzard in 2004.

We experienced production setbacks at Buzzard in 2011 due to unplanned maintenance, commissioning of a fourth platform and third-party pipeline restrictions. With the fourth platform now commissioned, Buzzard ended 2011 operating normally. We anticipate more robust and reliable production in 2012 and beyond.

We also sanctioned Golden Eagle in 2011—the second largest oil discovery of the past decade in the UK North Sea, after Buzzard—and achieved first oil at Blackbird, a UK North Sea discovery. We completed the Blackbird project safely, ahead of schedule and on budget.

We progressed on schedule towards first oil from Usan, which is expected to add 14,000 to 28,000 boe/d to our 2012 production and drive a step-change in cash flow.

We also made progress in the Gulf of Mexico, where Nexen is one of the largest deep-water lease holders. We were one of the first companies to receive a post-moratorium exploration well permit in the Gulf of Mexico deep water—a sign of the regulator's confidence in our ability to operate safely.

The Way Forward

Our conventional business provides both near-term production and longer-term growth prospects.

The largest portion of Nexen's 2012 capital program—up to $1.9 billion—is designated for conventional projects. We plan to extend our competitive advantage in the UK North Sea by starting up our Telford TAC and Rochelle tie-backs and advancing Golden Eagle. We expect first oil from Golden Eagle in late 2014.

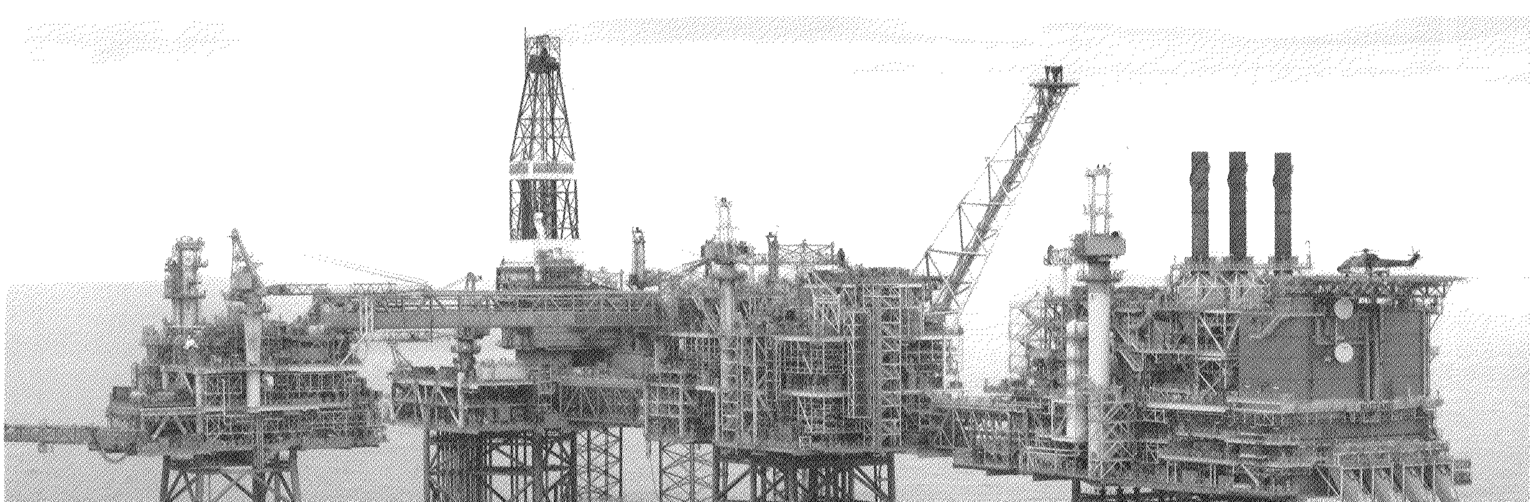
We achieved first oil at Usan in early 2012 and are ramping up production. In addition to providing significant near-term production, Usan offers a strong platform for future growth. We have several follow-up prospects in this area.

We will focus on proactive maintenance and improved reliability at all facilities, but with a particular focus on Buzzard. A scheduled maintenance shutdown at Buzzard in 2012 is part of our plan.

One of Nexen's most exciting prospects is Appomattox in the Gulf of Mexico deep water, where we've had two significant drilling successes to go along with our previous Vicksburg and Shiloh discoveries. We booked 65 million boe of probable reserves (net to Nexen) from our first Appomattox discovery and expect to add to that with our latest discovery.

In addition to supporting producing assets and bringing development projects on stream, we are planning significant exploration and appraisal in 2012, with material high-impact growth prospects and key discoveries in each of our core basins.

Our exploration team is executing well. We continue to improve our exploration success rate as well as the size and quality of our discoveries. Our success rate over the past five years places us among the top 20% of oil and gas explorers worldwide.



OIL SANDS

We are making progress at Long Lake. Plant reliability is improving, our higher quality wells are meeting expectations and we have a plan to fill the upgrader.

Each incremental barrel of production contributes significantly to cash flow, given the primarily fixed cost nature of the Long Lake facilities.

We have learned valuable lessons at Long Lake and have begun implementing a realistic plan to unlock value. We expect significant—and growing—cash flow as Long Lake turns the corner.

Why Oil Sands?

Nexen's oil sands assets represent a large, long-life resource. With an estimated three to six billion barrels of contingent recoverable resource[1], our oil sands business is expected to contribute decades of steady production, cash flow and value.

2011 Progress

Long Lake production was below expectations in 2011, primarily due to reservoir quality issues in our initial well set. We made significant progress in understanding these issues and developed a plan to address them. This action plan is well underway and will be a major driver in creating shareholder value.

Some Long Lake wells are located in resource characterized by higher amounts of shale and in "lean zones", areas of higher than average water content. This has resulted in lower production and higher steam-to-oil ratios than we anticipated. With significant additional geological and production data, we have enhanced our understanding of the reservoir performance. To fill the upgrader as quickly as possible, we have started to drill more wells in higher quality reservoir areas.

Our plans will advance with the support of a strong new partner at Long Lake. CNOOC took over OPTI Canada's 35% working interest in Long Lake in 2011. CNOOC brings to the table global technical expertise and the financial capability to allow our projects to move forward.

We have learned some valuable lessons at Long Lake. Among them: develop future projects in smaller, less complex phases and target the higher quality resource. These lessons will be applied to future phases.

We are making progress. Long Lake reached daily rates of approximately 35,000 bbls/d in early 2012 and plant reliability is improving. Our higher quality wells are performing in line with expectations. This gives us confidence that we can realize similar success on future wells. We also achieved positive cash flow at Long Lake in 2011 and expect significant—and growing—cash contributions as Long Lake production ramps up.

The Way Forward

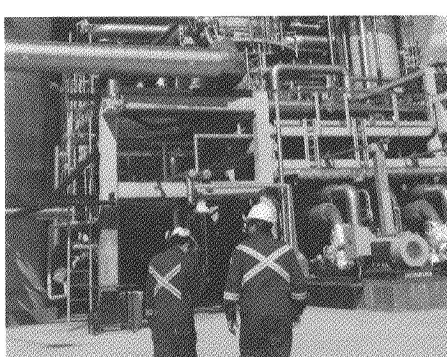
We have a realistic strategy to fill our upgrader. The centrepiece is a plan to drill 60 new wells at Long Lake and on a section of our Kinosis lease called K1A. We have already drilled 18 of those wells and have applied for regulatory approval for the remainder. We are also adding steam generation capacity and continue to improve plant reliability.

Our plan requires a $900 million incremental investment, net to Nexen, over the next few years. This is expected to provide a very attractive return because each incremental barrel of production contributes significant cash flow, given the primarily fixed-cost nature of the operations. Once ramped up, we expect Long Lake to generate about $850 million of cash flow annually (at current prices) for more than 40 years.

Production growth in 2012 will be partially offset by scheduled maintenance at both the upgrader and SAGD facilities in the third quarter. In addition to Long Lake, we expect Syncrude to continue to contribute about 21,000 to 23,000 bbls/d in 2012.

Nexen is also advancing other in situ expansion projects. We expect to sanction Hangingstone, a project operated by JACOS in which Nexen has a 25% working interest, in 2012. In addition to K1A, further in situ projects at Kinosis are due to follow.

The plan for Long Lake is clear. As we move forward, we are firmly focused on implementing that plan safely and reliably.



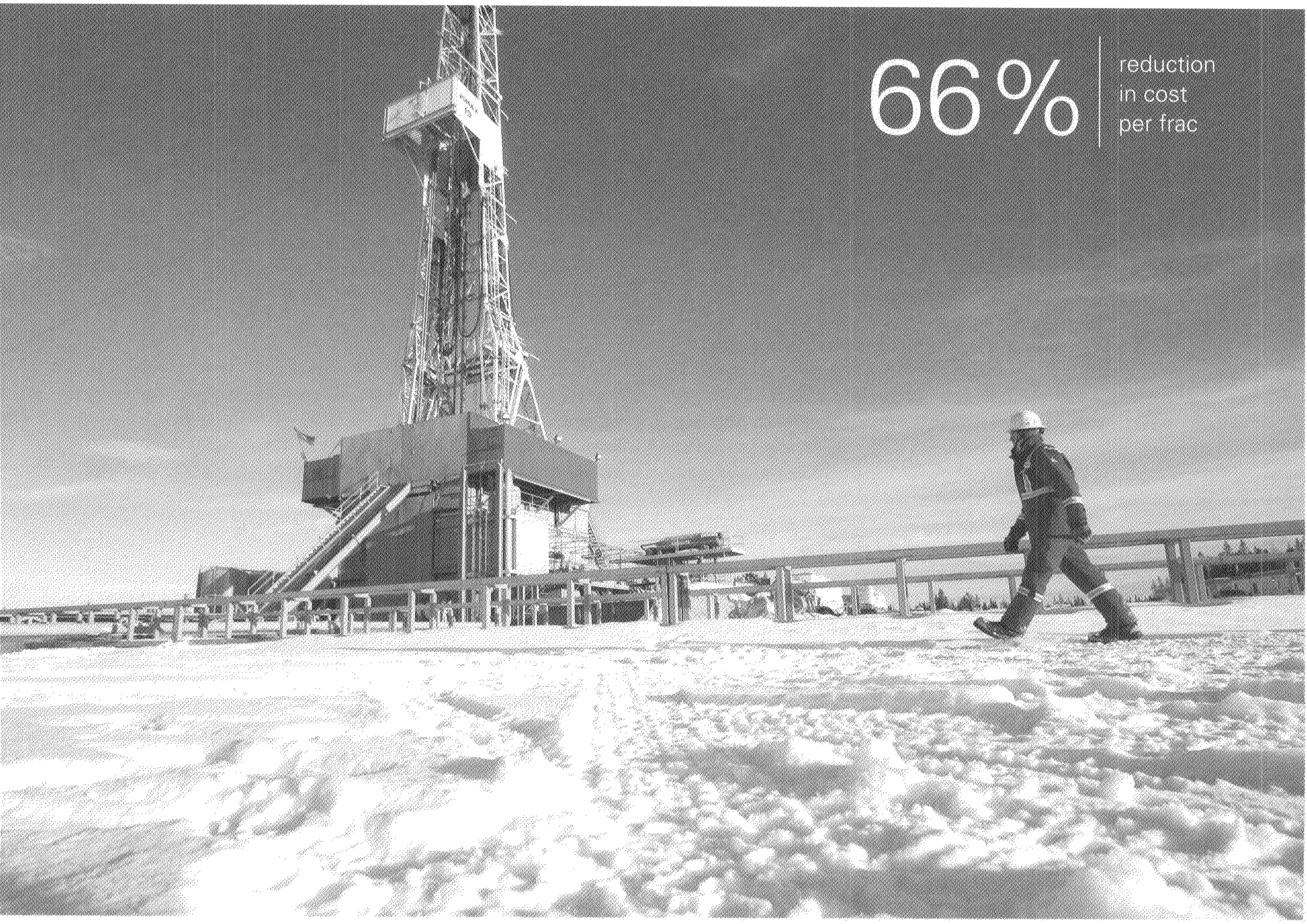
Oil Sands Action Plan

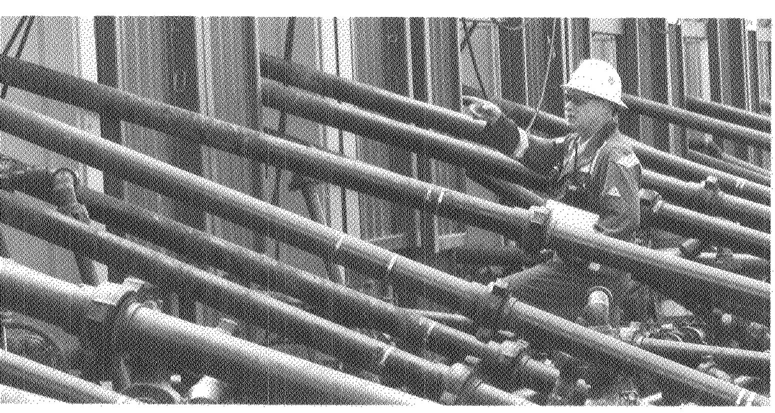
Here are some milestones to watch for as we implement our oil sands action plan:

- ❑ **Additional production from the continued optimization of Long Lake's initial 10 well pads**
- ❑ **Production on pad 11 ramping up to the 4,000 to 8,000 bbls/d capacity range**
- ❑ **Pads 12 and 13 on stream with first production expected in mid to late 2012**
- ❑ **Regulatory approvals of pads 14 and 15 and K1A**
- ❑ **Sanction of the Hangingstone project**
- ❑ **Advancement of future Kinosis SAGD development**

1 See press release dated November 15, 2010, available at www.nexeninc.com.

SHALE GAS





We have accumulated more than 300,000 acres of shale gas lands in British Columbia's Horn River, Cordova and Liard basins, containing an estimated four to 15 trillion cubic feet (tcf) of contingent recoverable resource[1] and five to 23 tcf of prospective resource[1].

With our INPEX/JGC joint venture, Nexen gains partners with world-class LNG expertise and access to Asian markets.

1 See press release dated November 15, 2010, available at www.nexeninc.com.

We continued to execute very well in our Canadian shale gas business in 2011. We also secured strategic partners and began exploring in Colombia and Poland.

Why Shale Gas?

Shale gas complements Nexen's oil-weighted portfolio and can be a source of material growth in the future when gas prices improve. Our shale gas properties in the Horn River, Cordova and Liard basins of northeastern British Columbia potentially contain enough resource to more than double the company's proved reserves.

2011 Progress

We continued to achieve industry-leading results in our shale gas drilling program in the Horn River Basin, where we completed a nine-well pad in 2011. We also began drilling our first 18-well pad.

The Horn River Basin is a top tier shale play, and Nexen is in the heart of it. We have excellent land tenure, a very large resource base and a strong team that has extensive experience from working in other shale gas basins. The results are evident: we have reduced our cost per frac by about 66% since 2009 and at the same time have improved our production rates per frac.

The calibre of Nexen's resource base and operating expertise were underscored by the joint venture agreement announced in 2011 with a consortium led by INPEX Corporation of Japan. Under this agreement, INPEX and its partner, JGC, acquire a combined 40% working interest in Nexen's shale gas holdings in northeast British Columbia at a premium to our invested cost. This joint venture is expected to close in the second quarter of this year.

We believe LNG export could be an attractive option for maximizing the value of our significant shale gas resource in the future. With this joint venture, Nexen gains partners with world-class liquefied natural gas (LNG) expertise and access to Asian LNG markets.

We also began to apply our shale gas expertise in international markets where gas prices are higher. In Poland, we entered a joint venture to explore in one of the most significant unconventional resource plays in central Europe. In Colombia, we began a drilling program near Bogota, the country's largest gas market.

The Way Forward

In an environment of relatively low natural gas prices, shale gas must compete for capital with other opportunities in Nexen's global oil-weighted portfolio. As a result, we will continue to make return-based investment decisions.

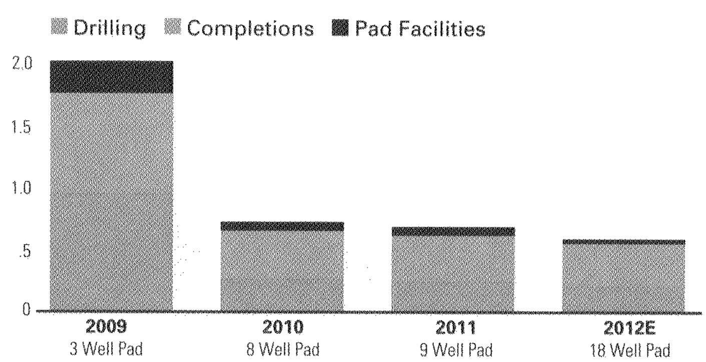
In British Columbia, we will continue what we started in 2011. We plan to expand facilities in the Horn River Basin to increase processing capacity and plan to bring our 18-well pad on stream late in the year. With these advances, we expect to achieve total gross production capacity of 175 mmcf/d.

We will continue to focus on cost reduction and superior execution. We are investigating a number of technologies that may bring both cost and environmental benefits.

In Poland and Colombia, we plan to evaluate the results from our recently drilled exploration wells before making any long-term investment decisions about the attractiveness and pace of development of this increasingly global commodity.

CAPITAL PER FRAC

(Cdn$ millions)



FINANCIAL STRENGTH

We continued to improve our financial strength in 2011 by reducing debt, capitalizing on premium Brent pricing and investing in high-impact growth opportunities.

We continue to strengthen our balance sheet
We have reduced net debt by approximately $2 billion in the past two years, using proceeds from the disposition of non-core assets, including our Canadian heavy oil business and Nexen's interest in Canexus. Most importantly, we achieved this while maintaining our capacity to fund future growth.

We capitalize on premium pricing
Approximately 70% of Nexen's total production attracts Brent pricing, which traded at an average of $16/bbl above WTI in 2011. Our hedging strategy allows us to benefit from these higher prices while providing some downside protection.

Cash flow is expected to grow faster than production in 2012
While production is likely to remain relatively flat in 2012 as we replace Yemen production, we expect to see a 15% increase in cash flow over 2011, on a price-neutral basis, due to higher margin barrels coming on stream in Nigeria.

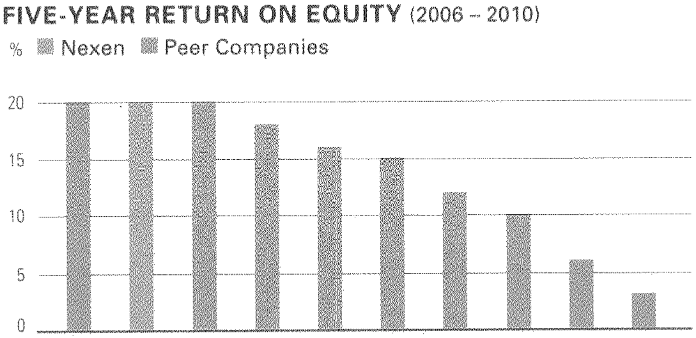
We have near-term growth in high-netback areas
Nexen's cash netbacks from oil and gas operations in 2011 averaged $40/boe after tax, among the highest in the industry. Most of our near-term growth projects are in high-netback areas such as West Africa, the UK North Sea and at Long Lake.

Our ability to form strategic partnerships is a competitive advantage
We are generating value from our assets by forming high-quality partnerships, such as our shale gas and Gulf of Mexico joint ventures. We partner with companies that are experienced, well capitalized and aligned with our growth plans.

Our resource base provides a strong foundation for future growth
We invested $2.5 billion in oil and gas activities in 2011 and added 73 million boe of proved reserves. These reserve additions replaced 96% of our 2011 production. Our 2.3 billion boe of proved plus probable reserves, along with our large inventory of attractive exploration prospects, provides a solid foundation for future growth.

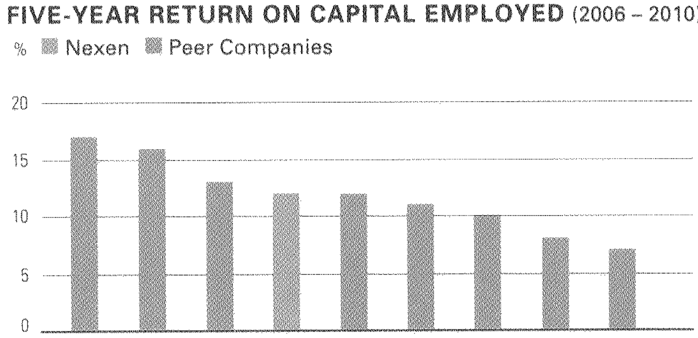
We generate solid returns on our investments
From 2006 to 2010, our return on equity was an industry-leading 20% (see chart below). Our return on capital employed was a mid-tier 12% over the same period. This is notable given we have about $7 billion invested in projects—Usan, Long Lake and shale gas—that aren't yet generating returns but are about to do so. With only $3.5 billion of net debt, we've already paid off about half of the investment with other cash flows.

FIVE-YEAR RETURN ON EQUITY (2006 – 2010)



Source: Street Research

FIVE-YEAR RETURN ON CAPITAL EMPLOYED (2006 – 2010)



Source: Street Research

RESPONSIBLE DEVELOPMENT

It's not just what we do that matters—it's how we do it. In 2011, we matched our best-ever injury rate, developed new Life Saving Rules and were recognized for our environmental and social performance.

Nexen's commitment to superior operating performance starts with a foundation of safe, responsible energy development. This approach helps us manage risk, operate reliably and maintain our social licence to operate. We believe a responsible approach is a competitive advantage.

Operating Safely

In 2011, we matched Nexen's best-ever injury rate as we continued to embed safety systems and culture into our business. Sadly, however, we experienced a contractor fatality in a vehicle accident on a British Columbia highway. We continue to work with our employees and contractors to reinforce driver safety.

To achieve continuous improvement in 2012 and beyond, we are implementing our new Life Saving Rules. This initiative is an industry best practice aimed at reducing the relatively small number of high-potential incidents that can harm people, the environment and our facilities.

We complement this focus on personal safety with an effort to eliminate process safety incidents—the unplanned release of hazardous material from industrial processes. Nexen is also active in a number of industry groups focused on oil spill prevention and emergency response. We worked closely with peers and regulators during the Gulf of Mexico drilling moratorium to implement lessons learned from the 2010 Macondo incident. In 2011, we were one of the first companies granted a permit to resume exploration drilling in the deep-water Gulf of Mexico.

Environmental and Social Responsibility

We believe a combination of technology, process improvements and stakeholder engagement will drive continued environmental and social progress in our industry.

In northeast British Columbia, for instance, we're investigating options to use saline groundwater as an alternative to fresh water for hydraulic fracturing. We also support new industry-wide operating practices launched in early 2012 to improve water management and reporting in Canadian shale gas operations.

Through organizations such as the Oil Sands Leadership Initiative (www.osli.ca), we are sharing information, best practices and lessons learned to meet or exceed the high standards of environmental and social performance expected of all oil sands operators. Although we made progress on many fronts in 2011, we recorded a higher than anticipated number of regulatory compliance exceedances at Long Lake. We took steps in the second half of 2011 to significantly reduce these incidents and that focus will continue in 2012.

We build strong relationships in communities where we operate around the world. We donated more than $11 million to community organizations in 2011 and actively engage, consult and collaborate with those closest to our operations. These efforts not only help build healthy communities, they support Nexen's social licence to operate and grow our business.

Our efforts have been recognized externally. In 2011 we were named to the Global 100 Most Sustainable Companies and the Dow Jones Sustainability Index.

For more information on Nexen's commitment to responsible development, see our sustainability report at www.nexeninc.com.

PERFORMANCE REVIEW

(Cdn$ millions, except as noted)	2011	2010	2009[9]	2008[9]	2007[9]
Highlights					
Dated Brent (Brent) (US$/bbl)	**111.28**	79.47	61.51	96.99	72.52
Average WTI Oil Price (US$/bbl)	**95.12**	79.52	61.80	99.65	72.31
Net Sales[1]	**6,169**	5,496	4,203	6,576	5,583
Cash Flow from Operations[2,3]	**2,368**	2,150	2,215	4,229	3,458
Per Common Share ($/share)	**4.49**	4.10	4.25	8.04	6.56
Net Income	**697**	1,127	536	1,715	1,086
Per Common Share ($/share)	**1.32**	2.15	1.03	3.26	2.06
Capital Expenditures, Including Acquisitions	**2,575**	2,724	3,578	3,203	3,524
Net Proceeds from Dispositions	**518**	1,264	17	6	4
Production[4,5]					
Production Before Royalties (mboe/d)	**207**	246	243	250	254
Production After Royalties (mboe/d)	**186**	220	213	210	207
Financial Position					
Working Capital	**263**	939	2,398	2,503	412
Property, Plant and Equipment, Net	**15,571**	14,579	15,492	14,922	12,498
Total Assets	**20,068**	19,647	22,900	22,155	18,075
Net Debt[6]	**3,538**	4,085	5,551	4,575	4,404
Long-Term Debt	**4,383**	5,090	7,251	6,578	4,610
Equity[7]	**8,373**	7,814	7,646	7,191	5,610
Shares and Dividends					
Common Shares Outstanding (millions)	**527.9**	525.7	522.9	519.4	528.3
Number of Registered Common Shareholders	**1,692**	1,745	1,725	1,624	1,569
Closing Common Share Price (TSX) (Cdn$/share)	**16.21**	22.80	25.22	21.45	32.10
Dividends Declared per Common Share (Cdn$/share)	**0.20**	0.20	0.20	0.175	0.10
Cash Flow from Operations[2,3]					
Conventional Oil and Gas					
United Kingdom	**3,085**	2,775	2,159	3,308	2,101
North America	**252**	359	270	897	659
Other Countries[8]	**390**	371	376	771	751
Oil Sands					
Syncrude	**405**	298	192	400	319
In Situ	**5**	(127)	–	–	–
	4,137	3,676	2,997	5,376	3,830
Interest, Marketing and Other Corporate Items	**(367)**	(567)	(154)	(563)	(187)
Income Taxes	**(1,402)**	(959)	(628)	(584)	(185)
Total Cash Flow from Operations	**2,368**	2,150	2,215	4,229	3,458

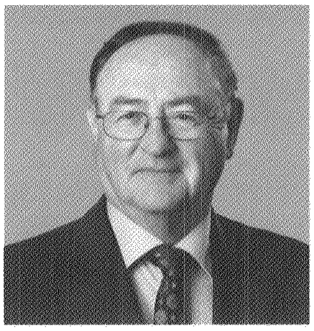
1 Represents net sales from continuing operations. 2 Cash flow from operations is defined as cash generated from operating activities before changes in non-cash working capital and other. 3 For reconciliation of this non-GAAP measure, please see our year-end press release dated February 16, 2012 or our Management's Discussion and Analysis. 4 Production is Nexen's working interest share and includes our share of production from Syncrude. 5 Natural gas is converted at 6 mcf per equivalent barrel of oil. 6 Net debt is defined as long-term debt and short-term borrowings less cash and cash equivalents. 7 Effective 2008, Canexus non-controlling interests are included in Equity. 8 Includes in-country cash taxes.
9 Financial amounts for 2009 and prior were prepared under previous Canadian Generally Accepted Accounting Principles and have not been restated for IFRS.

	2011	2010	2009	2008	2007
Production Before Royalties					
Crude Oil and NGLs (mbbls/d)					
United Kingdom	**85.0**	104.9	98.0	99.7	81.2
Canada	**–**	7.5	14.6	16.2	17.1
Long Lake Bitumen	**18.6**	15.9	7.9	3.9	–
Syncrude	**20.9**	21.2	20.2	20.9	22.1
United States	**8.2**	9.9	10.5	9.3	16.4
Yemen	**32.9**	41.3	49.9	56.6	71.6
Other Countries	**1.7**	2.1	3.5	5.8	6.2
	167.3	202.8	204.6	212.4	214.6
Natural Gas (mmcf/d)					
United Kingdom	**30**	35	24	18	16
Canada	**123**	126	139	131	118
United States	**86**	99	65	78	101
	239	260	228	227	235
Total Production Before Royalties (mboe/d)	**207**	246	243	250	254
Production After Royalties					
Crude Oil and NGLs (mbbls/d)					
United Kingdom	**84.7**	104.8	98.0	99.7	81.2
Canada	**–**	5.8	11.4	12.3	13.4
Long Lake Bitumen	**17.3**	15.1	7.9	3.9	–
Syncrude	**19.2**	19.6	18.6	18.2	18.8
United States	**7.4**	9.0	9.5	8.1	14.5
Yemen	**18.1**	23.1	29.8	30.6	39.8
Other Countries	**1.6**	1.9	3.2	5.3	5.7
	148.3	179.3	178.4	178.1	173.4
Natural Gas (mmcf/d)					
United Kingdom	**30**	35	24	18	16
Canada	**117**	116	128	109	98
United States	**78**	94	57	66	86
	225	245	209	193	200
Total Production After Royalties (mboe/d)	**186**	220	213	210	207
Oil and Gas Cash Netback Before Royalties[1,2] ($/boe)					
Producing Assets					
United Kingdom	**49.95**	43.87	59.06	87.70	67.85
Canada	**9.36**	11.16	16.07	32.97	20.07
In Situ	**9.84**	(26.67)	–	–	–
Syncrude	**55.85**	40.62	29.00	53.83	41.94
United States	**35.05**	33.78	28.80	56.42	42.28
Yemen	**31.33**	24.16	20.55	31.11	25.52
Other Countries	**86.92**	64.47	48.50	86.58	61.94
Company-Wide Oil and Gas	**40.20**	33.26	38.55	60.64	43.22

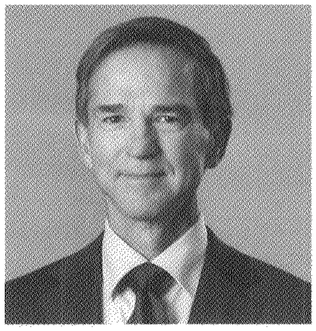
1 *Netbacks are defined as average sales price less royalties and other, operating costs and in-country taxes.*

2 *Financial amounts for 2009 and prior were prepared under previous Canadian Generally Accepted Accounting Principles and have not been restated for IFRS.*

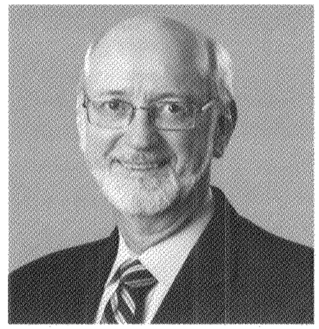
BOARD OF DIRECTORS



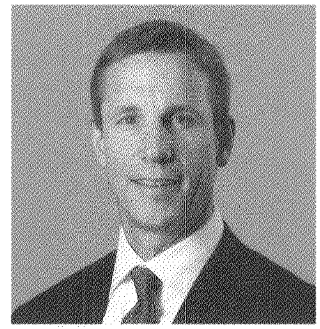
Francis Saville, Q.C.
Board Chair



William Berry

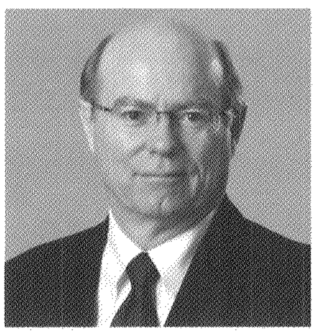


Robert Bertram

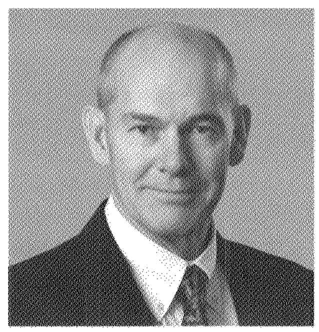


Thomas Ebbern

Dennis Flanagan



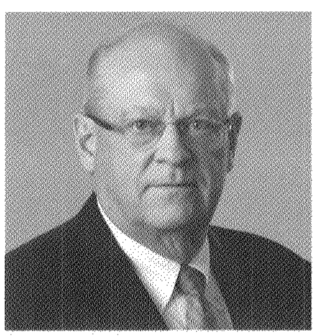
Barry Jackson



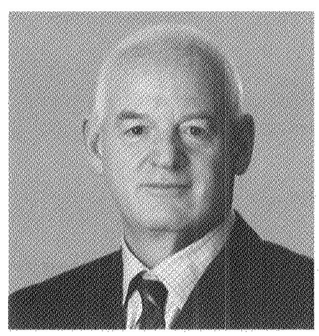
Kevin Jenkins

Anne McLellan, P.C., O.C.

Eric Newell, O.C.

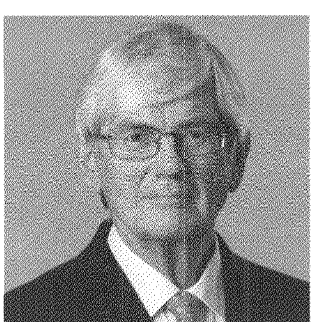


Thomas O'Neill

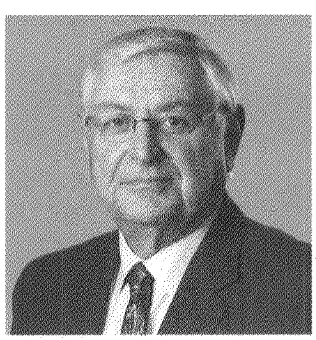


Kevin Reinhart

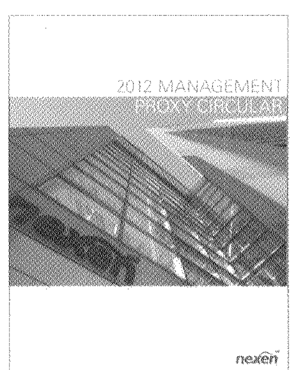
Arthur Scace, C.M., Q.C.



John Willson

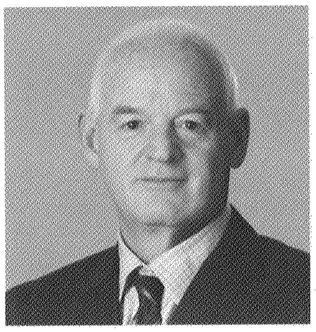


Victor Zaleschuk



See our 2012 Management Proxy Circular for director biographies and information on our approach to corporate governance at www.nexeninc.com.

EXECUTIVE LEADERSHIP TEAM



Kevin Reinhart

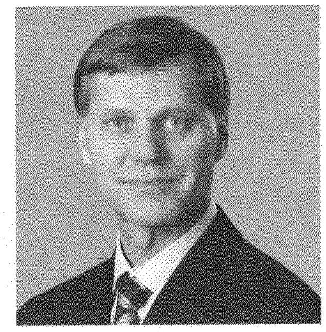
Interim President and
Chief Executive Officer

Una Power

Interim Chief Financial Officer and
Senior Vice President, Corporate
Planning & Business Development

Catherine Hughes

Executive Vice President, International
Oil and Gas

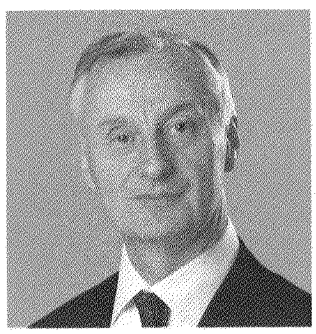


Jim Arnold

Senior Vice President,
Oil Sands

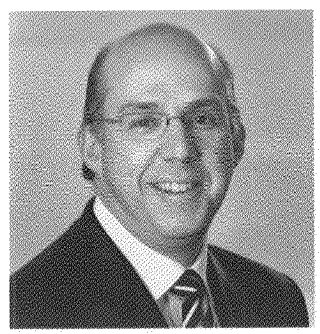
Ron Bailey

Senior Vice President, Canada



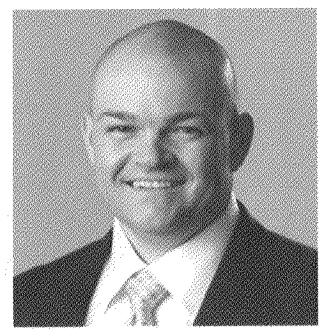
Alan O'Brien

Senior Vice President, General Counsel
and Secretary



Pierre Alvarez

Vice President,
Corporate Relations



Quinn Wilson

Vice President, Human Resources
and Corporate Services

Awards and Recognition

We're proud of the awards and recognition we receive. They help us benchmark against other companies, confirming what we do well and where we can improve. Most importantly, they reflect what we value—strong talent, transparency, good governance, responsible environmental stewardship and safe operations.

Global 100 Most Sustainable Corporations
from Corporate Knights magazine

Canada's Top 100 Employers
from MediaCorp Canada

50 Most Socially Responsible Corporations
by Maclean's magazine and Jantzi-Sustainalytics

Corporate Governance Global ranking 10 out of 10
from GovernanceMetrics International for governance disclosures and practices

Best 50 Corporate Citizens in Canada
from Corporate Knights magazine

FORWARD-LOOKING STATEMENTS

Certain statements in this report constitute "forward-looking statements" (within the meaning of the United States Private Securities Litigation Reform Act of 1995, as amended) or "forward-looking information" (within the meaning of applicable Canadian securities legislation). Such statements or information (together "forward-looking statements") are generally identifiable by the forward-looking terminology used such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook", "forecast" or other similar words and include statements relating to, or associated with, individual wells, regions or projects. Any statements as to possible future crude oil or natural gas prices; future production levels; future royalties and tax levels; future capital expenditures, their timing and their allocation to exploration and development activities; future earnings; future asset acquisitions or dispositions; future sources of funding for our capital program; future debt levels; availability of committed credit facilities; possible commerciality of our projects; development plans or capacity expansions; the expectation that we have the ability to substantially grow production at our oil sands facilities through controlled expansions; the expectation of achieving the production design rates from our oil sands facilities; the expectation that our oil sands production facilities continue to develop better and more sustainable practices; the expectation of cheaper and more technologically advanced operations; the expected design size of our facilities; the expected timing and associated production impact of facility turnarounds and maintenance; the expectation that we can continue to operate our offshore exploration, development and production facilities safely and profitably; future ability to execute dispositions of assets or businesses; future sources of liquidity, cash flows and their uses; future drilling of new wells; ultimate recoverability of current and long-term assets; ultimate recoverability of reserves or resources; expected finding and development costs; expected operating costs; the expectation of our ability to comply with the new safety and environmental rules at a minimal incremental cost, and of receiving necessary drilling permits for our US offshore operations; estimates on a per share basis; future foreign currency exchange rates; future expenditures and future allowances relating to environmental matters and our ability to comply therewith; dates by which certain areas will be developed, come on-stream or reach expected operating capacity; and changes in any of the foregoing are forward-looking statements.

Statements relating to "reserves" or "resources" are forward-looking statements, as they involve the implied assessment, based on estimates and assumptions that the reserves and resources described exist in the quantities predicted or estimated and can be profitably produced in the future.

All of the forward-looking statements in this report are qualified by the assumptions that are stated or inherent in such forward-looking statements. Although we believe that these assumptions are reasonable based on the information available to us on the date such assumptions were made, this list is not exhaustive of the factors that may affect any of the forward-looking statements and the reader should not place an undue reliance on these assumptions and such forward-looking statements. The key assumptions that have been made in connection with the forward-looking statements include the following: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve volumes; commodity price and cost assumptions; the continued availability of adequate cash flow and debt and/or equity financing to fund our capital and operating requirements as needed; and the extent of our liabilities. We believe the material factors, expectations and assumptions reflected in the forward-looking statements are reasonable, but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

Forward-looking statements are subject to known and unknown risks and uncertainties and other factors, many of which are beyond our control and each of which contributes to the possibility that our forward-looking statements will not occur or that actual results, levels of activity and achievements may differ materially from those expressed or implied by such statements. Such factors include, but are not limited to: market prices for oil and gas; our ability to explore, develop, produce, upgrade and transport crude oil and natural gas to markets; ultimate effectiveness of design or design modifications to facilities; the results of exploration and development drilling and related activities; the cumulative impact of oil sands development on the environment; the impact of technology on operations and processes and how new complex technology may not perform as expected; the availability of pipeline and global refining capacity; risks inherent to the operations of any large, complex refinery units, especially the integration between production operations and an upgrader facility; availability of third-party bitumen for use in our oil sands production facilities; labour and material shortages; risks related to accidents, blowouts and spills in connection with our offshore exploration, development and production activities, particularly our deep-water activities; direct and indirect risks related to the imposition of moratoriums, suspensions or cancellations of our offshore exploration, development and production operations, particularly our deep-water activities; the impact of severe weather on our offshore exploration, development and production activities, particularly our deep-water activities; the effectiveness and reliability of our technology in harsh and unpredictable environments; risks related to the actions and financial circumstances of our agents, contractors, counterparties and joint-venture partners; volatility in energy trading markets; foreign currency exchange rates; economic conditions in the countries and regions in which we carry on business; governmental actions including changes to taxes or royalties, changes in environmental and other laws and regulations including without limitation, those related to our offshore exploration, development and production activities; renegotiations of contracts; results of litigation, arbitration or regulatory proceedings; political uncertainty, including actions by terrorists, insurgent or other groups, or other armed conflict, including conflict between states; and other factors, many of which are beyond our control.

These risks, uncertainties and other factors and their possible impact are discussed more fully in the sections titled "Risk Factors" in our Annual Information Form and "Quantitative and Qualitative Disclosures About Market Risk" in our Management's Discussion & Analysis. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and management's future course of action would depend on our assessment of all information at that time.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity and achievements. Undue reliance should not be placed on the forward-looking statements contained herein, which are made as of the date hereof as the plans, intentions, assumptions or expectations upon which they are based might not occur or come to fruition. Except as required by applicable securities laws, Nexen undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. Included herein is information that may be considered financial outlook and/or future-oriented financial information (FOFI). Its purpose is to indicate the potential results of our intentions and may not be appropriate for other purposes. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

RESERVES AND RESOURCES

The resource estimates contained in this Letter to Shareholders represents the arithmetic sum of the following contingent and prospective resource estimates:

Best Estimates of Contingent and Prospective Resources (before royalties)

(billion boe)	Contingent Resources	Prospective Resources	Total Resources	Primary Product Type
Cdn Oil Sands[1]	4.0	–	4.0	Bitumen
Cdn Shale Gas[1]	1.3	2.1	3.4	Shale Gas
Conventional Exploration[2]	0.3	1.9	2.2	Light and medium oil
Other[3]	–	1.0	1.0	Shale Gas
Total	**5.6**	**5.0**	**10.6**	

1 Estimates prepared on September 30, 2010. See press release dated November 15, 2010.
2 US, UK, and Nigeria.
3 Colombia and Poland.

The total resource estimate presented here is the sum of our best estimates of the petroleum resource in our exploration and development portfolio, however, it does not accurately reflect the exploration risk associated with prospective resources because the sum of these different resource classes lies beyond the reasonable range of expected actual outcomes, and could therefore be misleading. Readers should give attention to the estimates of individual classes of resources to distinguish between the risks in estimates relating to discovered and undiscovered accumulations.

These estimates of contingent and prospective resource were made on December 31, 2011 (unless otherwise noted) and were prepared by qualified reserves evaluators. The estimated contingent and prospective resources reflect our best estimates of the quantities of resources that will actually be recovered. It is equally likely that the actual quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50% confidence level that the actual quantities recovered will equal or exceed the estimate. Nexen's estimates of contingent and prospective resources are based on definitions set out in the Canadian Oil and Gas Evaluation Handbook. Contingent resources are quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Prospective resources are quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of commerciality. Contingencies on resources may include, but are not limited to, factors such as economic, legal, environmental, political and regulatory matters or a lack of markets.

Specific oil sands contingencies precluding these contingent resources being classified as reserves include but are not limited to: project sanction, the cost and effectiveness of steam-assisted gravity drainage application, stakeholder and regulatory approvals, access to required services and infrastructure, oil prices and a demonstration of economic viability. There is no certainty that it will be commercially viable to produce any portion of these contingent oil sands resources.

Specific shale gas contingencies precluding these contingent resources located in northeast British Colombia, Poland and Colombia from being classified as reserves include but are not limited to: future drilling program and testing results, project sanction, the cost and effectiveness of fracing optimization, stakeholder and regulatory approvals, access to required services and field development infrastructure, gas prices and a demonstration of economic viability. There is no certainty that it will be commercially viable to produce any portion of these contingent shale gas resources. In the case of shale gas prospective resources there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

Specific light and medium oil contingencies precluding these offshore resources located in the US, UK and Nigeria from being classified as reserves include but are not limited to: the results of further appraisal drilling, costs, project sanction, stakeholder and regulatory approvals, access to required services and infrastructure, oil prices and a demonstration of economic viability. There is no certainty that it will be commercially viable to produce any portion of these contingent oil sands resources. In the case of light and medium oil prospective resources there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

For more information on the reserves estimates mentioned in this document, please refer to our 2011 Annual Information Form at www.nexeninc.com or www.sedar.com.

BUSINESS OVERVIEW

BUSINESS OVERVIEW

General Information	21
Corporate Structure	22
Business Overview	22
Oil and Gas	24
Understanding the Oil and Gas Industry	25
Conventional Oil and Gas	26
Oil Sands	32
Shale Gas	36
Energy Marketing	38
Reserves, Production and Related Information	38
Environmental and Regulatory Matters	59
Employees	62

Below is a list of terms specific to the oil and gas industry. They are used throughout this Annual Report.

/d	=	per day	boe	=	barrel of oil equivalent on the basis of 1 bbl to 6 mcf of natural gas
bbl	=	barrel	mboe	=	thousand barrels of oil equivalent
mbbls	=	thousand barrels	mmboe	=	million barrels of oil equivalent
mmbbls	=	million barrels	mcf	=	thousand cubic feet
mmbtu	=	million British thermal units	mmcf	=	million cubic feet
km	=	kilometre	bcf	=	billion cubic feet
MW	=	megawatt	WTI	=	West Texas Intermediate
GWh	=	gigawatt hours	Brent	=	Dated Brent
GJ	=	gigajoules	NGL	=	natural gas liquid
PSC™	=	Premium Synthetic Crude™	NYMEX	=	New York Mercantile Exchange
AECO	=	natural gas storage facility located in Alberta	$000s or $M	=	thousands of dollars
$MM	=	millions of dollars	US$	=	United States dollars

GENERAL INFORMATION

In this Annual Report, references to "we", "our", "us", "Nexen" or the "Company" mean Nexen Inc., our subsidiaries and partnerships.

Unless we indicate otherwise, all dollar amounts ($) are in Canadian dollars, and oil and gas volumes, reserves and related performance measures are presented on a working interest before-royalties basis. Where appropriate, information on an after-royalties basis is provided. The information contained in this Annual Report is dated December 31, 2011, unless otherwise indicated. The date of this discussion is February 15, 2012.

Conversions of gas volumes to boe in this Annual Report were made on the basis of 1 boe to 6 mcf of natural gas. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. Using the forecast prices applied to our reserves estimates, the boe conversion ratio based on wellhead value is approximately 30 mcf:1 bbl.

Accounting Matters

In February 2008, the Canadian Institute of Chartered Accountants announced that publicly accountable enterprises must adopt International Financial Reporting Standards (IFRS) by January 1, 2011. Accordingly, our consolidated balance sheet as at January 1, 2010 and the results of operations for the years ended December 31, 2011 and 2010 have been prepared in accordance with IFRS. The financial information presented in the 2011 Business Overview, Management's Discussion & Analysis (MD&A) and Consolidated Financial Statements has been prepared in accordance with IFRS as issued by the International Accounting Standards Board (IASB). In accordance with the Canadian IFRS transition rules, financial information before 2010 has not been restated. A description of the transition from previous Canadian generally accepted accounting principles (GAAP) to IFRS is included in Note 26 of our Consolidated Financial Statements.

Non-GAAP Measures

Certain financial measures referred to in this Business Overview, namely "cash flow from operations" and "net debt" do not have a standardized meaning prescribed by GAAP and are therefore unlikely to be comparable to similar measures presented by others. These non-GAAP measures are included to assist investors in analyzing Nexen's operating performance, leverage and liquidity. Reconciliations of these non-GAAP measures to their nearest GAAP equivalent are included in our MD&A.

Foreign Exchange

The noon-day Canadian to US dollar exchange rates for Cdn$1.00, as reported by the Bank of Canada, were:

(US$)	**December 31**	**Average**	**High**	**Low**
2007	1.0120	0.9304	1.0905	0.8437
2008	0.8166	0.9381	1.0289	0.7711
2009	0.9555	0.8757	0.9716	0.7692
2010	1.0054	0.9709	1.0054	0.9278
2011	0.9833	1.0117	1.0583	0.9430

On January 31, 2012, the noon-day exchange rate was US$0.9948 for Cdn$1.00.

CORPORATE STRUCTURE

Nexen Inc. is incorporated under the Canada Business Corporations Act. Our registered and head office is located at 801–7th Avenue S.W., Calgary, Alberta, Canada T2P 3P7.

Our material operating subsidiaries owned directly or indirectly and their jurisdictions of incorporation as at December 31, 2011 are as follows:

Name of Subsidiary	Jurisdiction of Incorporation/ Formation/Continuation
Nexen Petroleum UK Limited	England & Wales
Nexen Petroleum Nigeria Limited	Nigeria
Nexen Petroleum Offshore USA Inc.	Delaware
Nexen Marketing	Alberta
Canadian Nexen Petroleum Yemen	Yemen
Nexen Oil Sands Partnership	Alberta

All material operating subsidiaries are 100% beneficially owned, controlled or directed by us.

BUSINESS OVERVIEW

Nexen Inc. is an independent, Canadian-based, global energy company. We were formed in Canada in 1971 as Canadian Occidental Petroleum Ltd. when Occidental Petroleum Corporation combined their Canadian crude oil, natural gas, sulphur and chemical operations into one company.

Strategy

We create value by producing the energy resources that fuel people's lives. Our strategy is to capture resource early, maintain a portfolio of opportunities and create competitive advantage through technology, talent and experience. We seek to build a sustainable energy company focused on delivering on execution and exploiting our three key growth areas: i) conventional oil and gas; ii) oil sands; and iii) shale gas.

CONVENTIONAL OIL AND GAS

Our conventional oil and gas assets are comprised of large acreage positions in select basins including the UK North Sea, deep-water Gulf of Mexico and offshore West Africa. Strategically, we focus on these basins due to: i) past successes; ii) existing infrastructure in place; iii) significant potential in remaining resource; and iv) attractive fiscal terms. We assess our global portfolio of opportunities to identify prospects that we believe will generate the highest value in our selected basins.

In the UK North Sea, we are a significant regional player with concentrated assets, infrastructure and exploration potential for future growth. In addition to other producing properties, we operate the Buzzard field and platform, which is the largest discovery in the UK North Sea in over a decade. Other recent discoveries at Golden Eagle, Telford TAC and Rochelle are under development and are expected to provide new sources of production in the short-term. We continue to actively explore the UK North Sea basin including relatively under-explored areas such as west of the Shetland Islands.

In the Gulf of Mexico, we hold deep-water and shelf producing assets as well as several undeveloped deep-water discoveries including Appomattox, Vicksburg and Knotty Head. We are a significant leaseholder in the Gulf with access to deep-water drilling rigs. The deep-water Gulf of Mexico is near infrastructure and continental US markets.

We have several significant discoveries offshore West Africa, including Usan, Usan West, Ukot and Owowo. Development of the Usan field is nearing completion and first oil is expected in the next month or two. We are actively exploring the basin with several follow up prospects to pursue.

OIL SANDS

Our oil sands investments include interests in the Long Lake project, the Syncrude joint venture and 656,000 undeveloped acres (gross) in the Athabasca oil sands in northern Alberta. Our oil sands strategy is to generate steady and predictable cash flow for decades. While the cost to produce from the Athabasca oil sands is higher relative to conventional oil deposits, the significant discovered resource base and stable fiscal jurisdiction make this a key source of future oil development.

We first entered the oil sands by acquiring an interest in the Syncrude joint venture. Syncrude produces synthetic crude oil from mined bitumen-saturated sands.

Our in situ oil sands project at Long Lake produces and upgrades bitumen in the Athabasca oil sands. Steam-assisted-gravity-drainage (SAGD) bitumen production began in 2008 and production of PSC™ from the upgrader began in 2009. Our near-term plans include development of the Kinosis lease, a source of in situ bitumen to provide additional feedstock for the Long Lake upgrader.

SHALE GAS

We have over 300,000 acres of shale gas lands in the Horn River, Cordova and Liard basins in northeast British Columbia. Our shale gas strategy is currently focused primarily on the Horn River basin. The Horn River basin is a significant shale gas play with high resource density and strong well productivity. In November 2011, we signed an agreement to farm-out a 40% working interest in our shale gas lands in northeast British Columbia to a consortium led by INPEX Corporation. The sale is expected to close in the second quarter of 2012. In 2011, we expanded our shale gas portfolio by acquiring a non-operated interest in Poland and by beginning to test shale gas opportunities in Colombia.

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

Three–Year Overview

2009[1]	• Generated cash flow from operations of \$2.2 billion and net income of \$536 million • Discovered the Hobby field in the UK North Sea, the first discovery of our Golden Eagle area • Acquired an additional 15% working interest in the Long Lake project and completed first major turnaround to address steam reliability issues • Produced first PSC™ from Long Lake • Issued \$1 billion of 10-year and 30-year senior notes • Discovered Owowo field, offshore West Africa
2010	• Generated cash flow from operations of \$2.2 billion and net income of \$1.1 billion • Discovered the Appomattox field in the deep-water Gulf of Mexico • Disposed of non-core, heavy oil properties in Western Canada for \$939 million • Divested of non-core marketing businesses including North American natural gas marketing • Doubled bitumen production at Long Lake with improved steam reliability • More than doubled our British Columbia shale gas acreage, adding lands in the Cordova and Liard basins
2011	• Generated cash flow from operations of \$2.4 billion and net income of \$697 million • Completed a non-core asset disposition program with the sale of our interest in Canexus for \$458 million • Repaid approximately \$800 million of long-term debt • Moored the Usan floating production and storage offloading vessel (FPSO) at site in offshore West Africa with final commissioning underway • Developed action plans to increase production at Long Lake and fill the upgrader; ramped-up pad 11, drilled pads 12 and 13 and progressed regulatory process for pads 14, 15 and Kinosis K1A • Commissioned the Buzzard fourth platform to handle higher levels of H_2S from the field • Achieved first oil at our Blackbird field in the UK North Sea • Received government approval and sanctioned the Golden Eagle development in the UK • Brought a nine-well pad on-stream and began drilling an 18-well pad at Horn River • Entered into an agreement to farm-out a 40% working interest in our northeast British Columbia shale gas operations for \$700 million

1 Financial amounts for 2009 and earlier were prepared under previous Canadian Generally Accepted Accounting Principles and have not been restated for IFRS. Amounts for 2010 and 2011 were prepared under IFRS.

In 2012, we expect the following changes to our businesses:

- **UK North Sea**—progress development of our Golden Eagle discovery, bring tie-backs at Telford TAC and Rochelle on-stream and continue to explore the UK North Sea basin with seven exploration and appraisal wells planned.
- **Gulf of Mexico**—complete the Kakuna exploration well, continue appraisal of the Appomattox discovery and test other identified deep-water Gulf of Mexico opportunities with six exploration and appraisal wells planned.
- **Offshore West Africa**—complete commissioning of the Usan FPSO with first oil production in the next month or two and continue exploration of our acreage.
- **Long Lake**—progress towards filling the upgrader to capacity by optimizing bitumen production from additional Long Lake well pads and accelerating development of the Kinosis bitumen resource.
- **Shale Gas**—close the sale of the 40% working interest in our northeast British Columbia shale gas operations, bring the first 18-well pad on stream and expand field processing capacity at Horn River and continue exploration activities in Poland and Colombia.

OIL AND GAS

In this Business Overview, we provide estimates of remaining quantities of proved and probable crude oil, synthetic oil, bitumen, coal bed methane (CBM), shale gas and natural gas reserves (oil and gas reserves) for our various properties as at December 31, 2011. These reserves estimates and related disclosures have been prepared in accordance with National Instrument 51-101—*Standards of Disclosure for Oil and Gas Activities* (NI 51-101). We have also prepared reserves estimates and disclosures in accordance with SEC requirements, which are included in Appendix B of our 2011 Annual Information Form (AIF) which is available from our public filings with the Canadian Securities Administrators at www.sedar.com or from our website www.nexeninc.com. Reserves estimates and disclosures prepared in accordance with NI 51-101 requirements differ from reserves estimates prepared in accordance with SEC requirements. Significant qualitative differences between and disclosures are described in the section entitled "Special Note to Investors" on page 58.

Our proved and probable reserve estimates have been internally prepared. For our reserves estimates prepared in accordance with NI 51-101 requirements, we had 96% of our proved reserves assessed (either evaluated or audited as described on pages 55 to 56) by independent reserves consultants. Their assessment of the proved reserves is performed at varying levels of property aggregation, and we work with them to reconcile any difference on the portfolio of properties to within 10% in the aggregate. Estimates pertaining to individual properties within the portfolio may differ by more than 10% either positively or negatively, however, we believe such differences are not material relative to our total proved reserves.

We also had 98% of our NI 51-101 proved plus probable oil and gas reserves estimates assessed by independent reserves consultants. By definition, proved reserves must be determined together with probable reserves (see definition on page 57). As such, the independent reserves consultants' assessments are prepared on a combined proved plus probable basis. Like proved reserves, their assessment of the proved plus probable reserves is performed at varying levels of property aggregation, and we work with them to reconcile any difference on the portfolio of properties to within 10% in the aggregate. Estimates pertaining to individual properties within the portfolio may differ by more than 10% either positively or negatively, however, we believe such differences are not material relative to our total proved plus probable reserves.

Refer to the section on Basis of Reserves Estimates on pages 39 to 40 for a description of our internal reserves process and the nature and scope of the independent assessments performed on our proved and probable reserves estimates and the results thereof.

UNDERSTANDING THE OIL AND GAS INDUSTRY

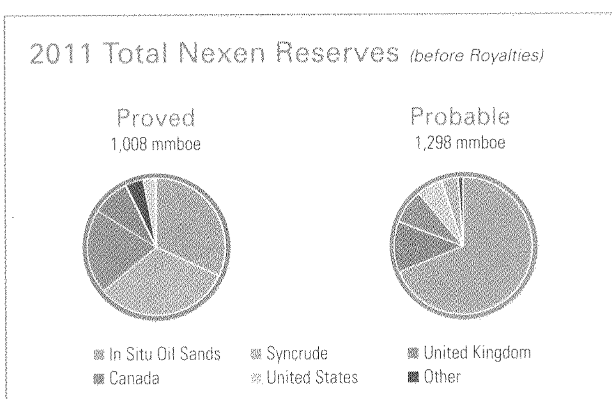
The oil and gas industry is highly competitive. With strong global demand for energy and limited exploration opportunities, there is intense competition to find and develop new sources of supply. Yet, barrels from different reservoirs around the world do not have equal value. Their value depends on the costs to find, develop and produce the oil or gas, the fiscal terms of the host regime and the price that products attract based on quality, location and marketing efforts. We captured an inventory of opportunities in our core growth areas, and our goal is to extract the maximum value from each barrel of oil equivalent so that every dollar of capital we invest generates an attractive return.

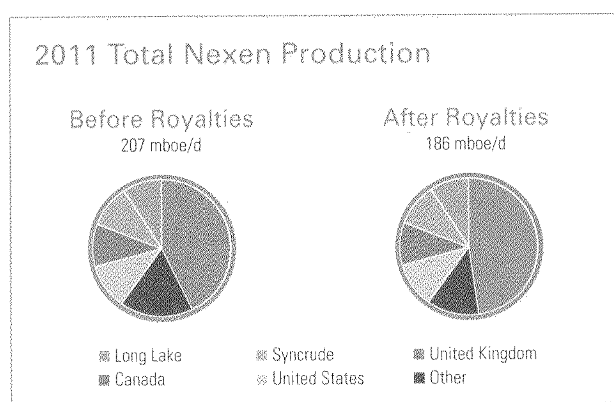
Numerous factors can affect this. Changes in crude oil and natural gas prices can significantly affect our net income and cash flow generated from operations. Consequently, these prices may also affect the carrying value of our oil and gas properties and how much we invest in oil and gas exploration and development. We attempt to reduce these impacts by investing in projects we believe will generate positive returns at relatively low commodity prices, and we maintain liquidity that provides us with the ability to sustain capital investment in high-quality projects during periods of low commodity prices.

The prices we receive for our oil and gas products are determined by global crude oil and regional natural gas markets, all of which can be volatile. With many alternative customers, the loss of any one customer is not expected to have a materially adverse effect on the price of our products or revenues. Oil and gas producing operations are generally not seasonal. However, demand for some of our products such as natural gas can fluctuate season to season, which impacts price. We manage our operations on a country-by-country basis, reflecting differences in the regulatory regime, competitive environments and risk factors associated with each country.

Presentation of our oil and gas operations is separated between conventional oil and gas activities, and oil sands activities. Our conventional operations include our oil and gas operations in the UK North Sea, North America (excluding oil sands) and other countries (Yemen, offshore West Africa, Colombia and other). Our oil sands activities are segregated between in situ oil sands operations (primarily at Long Lake) and our interest in Syncrude. Our shale gas results are included in the North America segment until they become significant.

Production, revenues, net income, capital expenditures and identifiable assets for these segments appear in Note 25 to the Consolidated Financial Statements and in our MD&A.





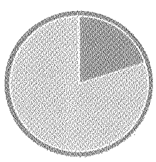
CONVENTIONAL OIL AND GAS

United Kingdom (UK) – North Sea

- We are the second largest oil producer in the UK North Sea.
- We are developing our Golden Eagle discovery, with first oil expected in late 2014.
- We continue to actively explore the North Sea, with seven exploration and appraisal wells planned for 2012.

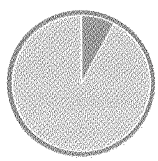
2011 Share of Nexen Reserves *(before Royalties)*

Proved
202 mmboe



20%
United Kingdom

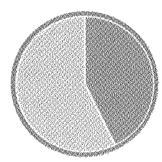
Probable
105 mmboe



8%
United Kingdom

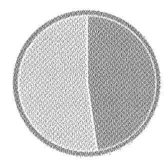
2011 Share of Nexen Production

Before Royalties
90 mboe/d



43%
United Kingdom

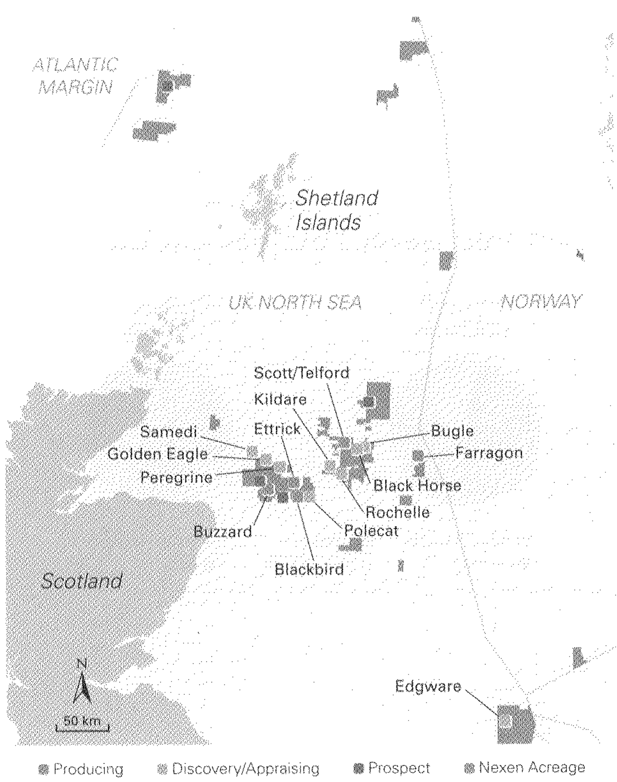
After Royalties
90 mboe/d



48%
United Kingdom

The UK North Sea is a key producing area for Nexen. Our primary assets, which we operate, include a 43.2% interest in the Buzzard field and facilities, a 41.9% interest in the Scott field and production platform, an 80.4% interest in the Telford field, a 79.7% interest in the Ettrick field and a 90.6% interest in the Blackbird field, along with interests in several undeveloped discoveries and approximately 971,000 net undeveloped exploration acres. We are a significant regional player with concentrated assets, infrastructure and exploration potential for future growth. Our UK North Sea operations complement our global portfolio with significant cash flow generation and the opportunity for short cycle-time production growth.

Our UK strategy is to grow our existing North Sea production and identify new sources of production. To do this, we identify exploration and exploitation opportunities near existing infrastructure that can be tied-in economically in a short time period. We also seek to establish new core areas through exploration in relatively unexplored areas of the basin (e.g. west of Shetlands, the Central Graben and the northern North Sea). We target oil-focused assets that are early life and generate strong cash margins.



BUZZARD

The Buzzard field is located about 60 miles northeast of Aberdeen in the Outer Moray Firth, central North Sea, in 317 feet of water. Buzzard is the largest discovery in the UK North Sea in over a decade. It was discovered in 2001 and came on stream in early 2007. The Buzzard development was initially comprised of three platforms capable of processing at least 200,000 bbls/d of oil and 60 mmcf/d of gas. A fourth platform with production-sweetening facilities to handle higher levels of hydrogen sulphide was completed in 2011. Oil from Buzzard is exported via the Forties pipeline to the Kinneil Terminal in Scotland. Gas is exported via the Frigg system to the St. Fergus Gas Terminal in northeast Scotland.

We expect to produce the Buzzard field through 36 production wells and maintain reservoir pressure with an active water-flood program. We have drilled 30 of these wells to date. Our share of production in 2011 was 62,400 boe/d. In 2012, we expect to drill five additional production wells and one appraisal well in the Buzzard field.

SCOTT/TELFORD

The Scott field began producing in 1993, while Telford was tied back to the Scott platform and came on stream in 1996. Most of our oil and gas from these fields is produced through subsea wells tied back to the Scott platform. Oil is delivered to the third-party Kinneil Terminal in Scotland via the Forties pipeline, while gas is exported via the SAGE pipeline to the St. Fergus Gas Terminal in northeast Scotland. Recently, successful extension drilling of the Telford field exceeded expectations and extended the field's proved reserves. The TAC and TAE Telford development wells are expected to be on stream in 2012 and 2013, respectively. The nearby Rochelle gas field is planned to be tied back to the Scott platform in 2012. Scott/Telford produced 13,000 boe/d (net to us) in 2011. We plan to drill two additional development wells in 2012 at Telford.

ETTRICK/BLACKBIRD

Ettrick is a producing field originally discovered in 1981 and brought on stream in 2009. Oil and gas is produced from the fields through seven subsea wells tied back to a leased FPSO. The FPSO is designed to handle 30,000 bbls/d of oil and 35 mmcf/d of gas and to re-inject 55,000 bbls/d of water. The produced oil is offloaded from the FPSO onto tankers and typically delivered to ports in the North Sea. Production from the nearby Blackbird field came on stream late in 2011 and is produced through the Ettrick FPSO. Our share of production from Ettrick/Blackbird in 2011 was 14,000 boe/d. We expect to drill two development wells in 2012, one in each field.

GOLDEN EAGLE

In 2007, we made a discovery at Golden Eagle, followed by Peregrine (formerly Pink) in 2008 and Hobby in 2009. We refer to these three discoveries as the Golden Eagle area and hold a 36.5% operated interest. Since the original discovery, we successfully completed a comprehensive appraisal program, which included drilling nine appraisal wells, two drill-stem tests and one injection test. In 2011, we completed the appraisal work, explored additional acreage, sanctioned the development plan and received government approval. The Golden Eagle development will include a two-platform stand-alone facility with production capacity of about 70,000 boe/d (26,000 boe/d net to us) at full rates. In 2012, we expect to advance the development of the Golden Eagle area and begin to fabricate the platforms and facilities. Development drilling in the field is expected to start in 2013 and first oil is expected in late 2014. Our net investment is expected to be $1.2 billion over the next three years.

EXPLORATION

We hold approximately 68 blocks in the UK North Sea. We continue to actively explore the basin and hold several undeveloped discoveries on operated blocks near the Golden Eagle, Scott and Buzzard facilities as follows:

Field	Interest *(%)*	Operator Status	Comments
Blackhorse	50	operated	discovery near Scott, evaluating development alternatives
Bright	80	operated	discovery near Buzzard, evaluating development alternatives
Bugle	100	operated	discovery near Scott, evaluating development alternatives
Kildare	50	operated	discovery near Scott; evaluating development alternatives
Marten	40	operated	discovery near Buzzard, evaluating development alternatives
Polecat	100	operated	discovery near Buzzard; evaluating development alternatives
Samedi	100	operated	discovery near Golden Eagle, evaluating development alternatives

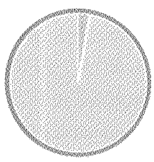
In the UK North Sea, we plan to drill a total of four exploration wells and three appraisal wells in 2012.

United States (US) — Gulf of Mexico

- **We are a significant leaseholder in the deep-water Gulf of Mexico.**
- **We are appraising our Appomattox discovery in the emerging Norphlet play.**

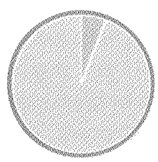
2011 Share of Nexen Reserves *(before Royalties)*

Proved
34 mmboe



3%
United States

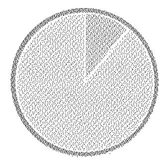
Probable
82 mmboe



6%
United States

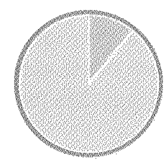
2011 Share of Nexen Production

Before Royalties
22 mboe/d



11%
United States

After Royalties
21 mboe/d

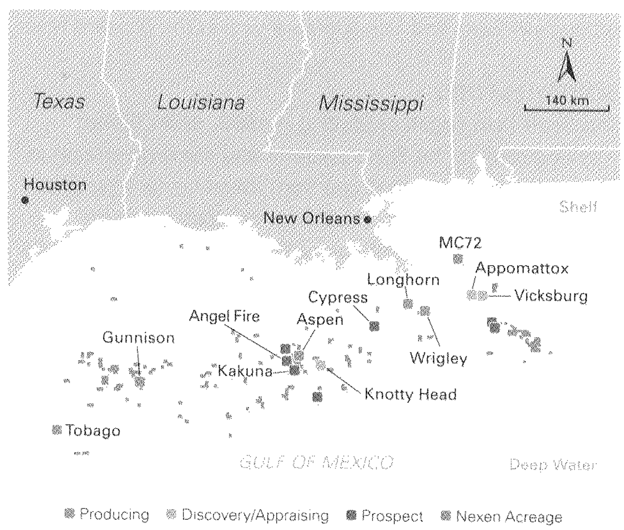


11%
United States

The deep-water Gulf of Mexico is an integral part of our growth strategy. Existing production infrastructure, the potential for material discoveries and attractive fiscal terms make the deep-water Gulf of Mexico one of the world's most prospective basins for oil and gas. While costs of deep-water exploration are typically higher, prospects generally have multiple sands and higher production rates—factors that can enhance economics. The deep-water Gulf is near infrastructure and continental US markets, so discoveries can be brought on stream in reasonable time frames relative to less developed or more remote areas of the world. We currently focus our exploration program on Miocene sub-salt plays and Norphlet targets in the central Gulf of Mexico.

Over the past few years, we have built our resources and capabilities to explore in the deep water by accumulating a large inventory of high-quality acreage and gained access to two new-build deep-water drilling rigs.

Our existing Gulf of Mexico production and reserves are primarily concentrated in six deep-water and four shallow-water (shelf) areas. Our oil and natural gas production is transported to the continental US for sale via third-party pipelines and infrastructure. Our share of production from the Gulf of Mexico in 2011 was 22,600 boe/d (20,400 boe/d after royalties).



DEEP WATER

Most of our deep-water production comes from our 25% non-operated Longhorn field, our 100% operated Aspen field, our 50% non-operated Wrigley field, and our 30% non-operated Gunnison field. Our share of 2011 deep-water production before royalties was 16,400 boe/d (15,300 boe/d after royalties).

Our Longhorn property is on Mississippi Canyon Blocks 502 and 546 in 2,400 feet of water. The project is a non-operated four-well subsea tie-back to the Corral platform located 19 miles north of the field. Longhorn came on stream in late 2009 and produced 7,900 boe/d (net to us) in 2011.

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

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

Gunnison is in 3,100 feet of water and includes Garden Banks Blocks 667, 668 and 669. Gunnison began production in late 2003 through a truss SPAR platform that can handle 40,000 bbls/d of oil and 200 mmcf/d of gas.

Green Canyon 6/137 is in water depths of 650 feet. Production from this field is currently suspended as the third-party platform that processed our oil and gas was destroyed by Hurricane Ike in September 2008. A tie-back to existing third-party facilities to restore production is under construction and production is expected to resume in 2012.

SHELF

Our shelf producing assets are offshore Louisiana, primarily in four 100%-owned field areas: Eugene Island 255/257/258/259, Eugene Island 295, Vermilion 76 and West Delta. Given the mature nature of these assets, our 2012 capital investment on these assets is expected to be minimal.

EXPLORATION

We hold approximately 205 blocks in the Gulf of Mexico and expect this acreage and future exploration opportunities to position us for growth. Our undeveloped deep-water discoveries include:

Well	**Interest** *(%)*	**Operator Status**	**Comments**
Appomattox	20	non-operated	discovery; appraisal underway
Knotty Head	25	non-operated	discovery; currently evaluating development options
Vicksburg	25	non-operated	discovery; further appraisal required

In 2010, we completed a successful exploration well and sidetrack at Appomattox, approximately six miles west of our Vicksburg discovery. Results of these activities indicated a significant oil discovery with the potential to extend the discovery. In 2011, appraisal drilling recommenced at Appomattox following the end of the US Government drilling moratorium. In early 2012, a successful well on the northeast fault block encountered oil play and we are completing an evaluation to determine the size of the discovery. Additional wells are planned in 2012 to further delineate these discoveries. During 2011, we progressed development studies at Knotty Head and began drilling operations at Kakuna, a 52.5% operated deep-water exploration well targetting the Miocene sub-salt play. Results from this well are expected in 2012. In 2011, we received a drilling permit from the US Government to drill the deep-water Angel Fire prospect, which we expect to spud during 2012.

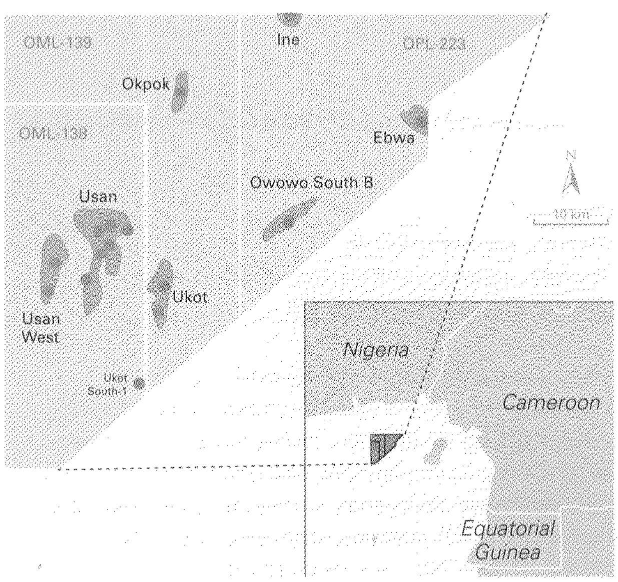
In 2012, we plan to drill up to six exploration and appraisal wells in the deep-water Gulf of Mexico, focusing on the Miocene sub-salt play and following up on the success in the Norphlet play.

Other International

- Our entry into Yemen kicked off our international expansion in the early 1990s, which provided us with other international opportunities.
- Development of the Usan field, offshore Nigeria is nearing completion and first oil production is expected in the next month or two.
- In Nigeria, we have several discoveries and additional exploration prospects beyond Usan.

NIGERIA

Offshore West Africa is a core area with several discoveries that offer relatively low risk exploration for prolific reservoirs supported by 3D seismic data. Our strategy here is to complete development of the Usan discovery and continue to explore our existing portfolio of multiple prospects in this oil-rich region to provide medium to long-term growth.



Exploration and Appraisal Wells Discovery Exploration Blocks

In 1998, we acquired a 20% non-operated interest in Block OPL–222, which covers 448,000 acres approximately 80 km offshore in water depths ranging from 200 to 1,200 metres. In 1998, we discovered the Ukot field comprised of three oil-bearing intervals and in 2002, the Usan field was discovered, with seven successful wells confirming the presence of significant hydrocarbon accumulations. In 2007, OPL– 222 was converted to two Oil Mining Leases, OML–138 and 139. The Usan development is within OML–138.

Development of the Usan field is progressing and expected to come on stream in the next month or two, with peak facility capacity of 180,000 bbls/d (36,000 bbls/d, net to us). The FPSO and initial subsea facilities were completed and installed in the field during 2011. The FPSO, capable of storing up to two million barrels of oil, is undergoing final hook-up and commissioning. Oil will be offloaded onto tankers for delivery to customers.

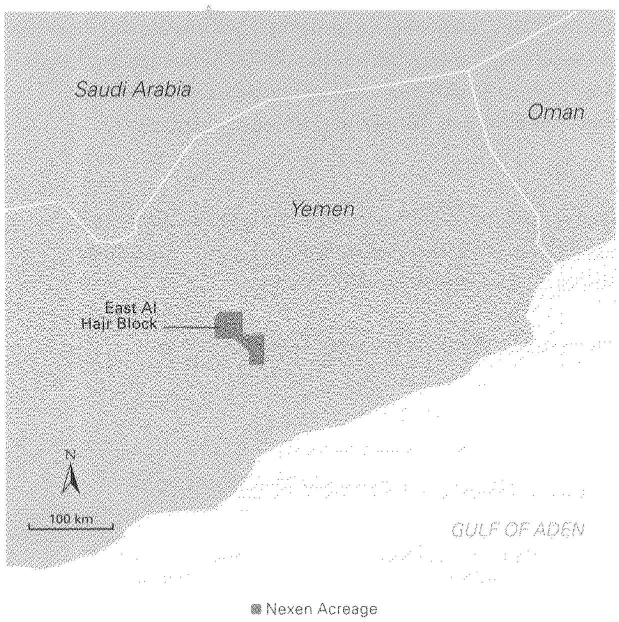
In 2008, we acquired an 18% non-operated interest in Block OPL–223, covering 230,000 acres, which provides us with significant exploration potential contiguous with our other licenses. In 2009, we drilled the Owowo South B-1 exploration well in the southern portion of Block OPL–223, in 670 metres of water, 20 km east of the Usan field. Under the Production Sharing Contract governing OPL–223, the Nigerian National Petroleum Corporation is the concessionaire of the license. All of our licenses in Nigeria are operated by Total Exploration & Production Nigeria Ltd. We are planning a multi-well exploration and appraisal drilling program in 2012 to test and delineate our Nigeria portfolio.

As is typical in many jurisdictions, the Nigerian government is reviewing its existing petroleum fiscal terms, including those applicable to our interests, the impact of which could negatively affect the economics of our projects.

YEMEN

Yemen was a significant international region for us since we first began production at Masila on Block 14 in 1993. We operated Masila, the country's largest oil project, for 18 years and developed strong relationships with the government and local communities. On December 17, 2011, the Masila production sharing agreement (PSA) expired and production, operations, central processing facility, main oil pipeline and export facilities were transferred to the Yemen Government. We continue to operate the East Al Hajr facility (Block 51) and our strategy is to maximize the remaining value of the block.

Production from Yemen in 2011 was 32,900 bbls/d (18,100 bbls/d after royalties).



East Al Hajr Block (Block 51)

The first successful exploratory well was drilled in 2003 and development of the block began in 2004, which included a central processing facility (CPF), gathering system and a 22 km tie-back to an export oil pipeline. Production commenced in late 2004 and approximately 69 wells are currently on stream. Oil is delivered to customers via tankers in the Gulf of Aden.

We operate Block 51, which is governed by the Block 51 PSA between the Government of Yemen and the East Al Hajr partners (EAH Partners); The Yemen Company (TYCO) (12.5% carried working interest) and Nexen (87.5% working interest). Under the PSA, TYCO has no obligation to fund capital or operating expenditures and, therefore, our effective interest is 100% and, for purposes of accounting and reserves recognition, we treat TYCO's 12.5% participating interest as a royalty interest. The PSA expires in 2023.

COLOMBIA

In 2000, we made a discovery at Guando on our 20% non-operated Boqueron Block, and production from the Guando field began in 2001. Boqueron is in the Upper Magdalena Basin of central Colombia, approximately 100 km southwest of Bogota. Under terms of our licence, our working interest in Guando decreased from 20 to 10% during the second quarter of 2009, as cumulative oil production from the field reached 60 million barrels. Our share of production in Colombia in 2011 was 1,700 bbls/d (1,600 bbls/d after royalties).

We currently hold interests in six exploration and production blocks in the Upper Magdalena Basin and the Eastern Cordillera area. In the Upper Magdalena Basin, we hold a 10% interest in the Boqueron block and a 50% non-operating interest in the Villarrica Norte Block. In the Eastern Cordillera area, we hold a 100% interest in the Chiquinquira, Sueva, Barbosa and Garagoa exploration and production blocks.

OIL SANDS

- We operate the Long Lake project, an integrated SAGD and upgrader process.
- Syncrude has been operating for over 30 years and provides steady predictable cash flows.
- We have significant undeveloped acreage in the Athabasca oil sands, totaling over 656,000 acres (gross).

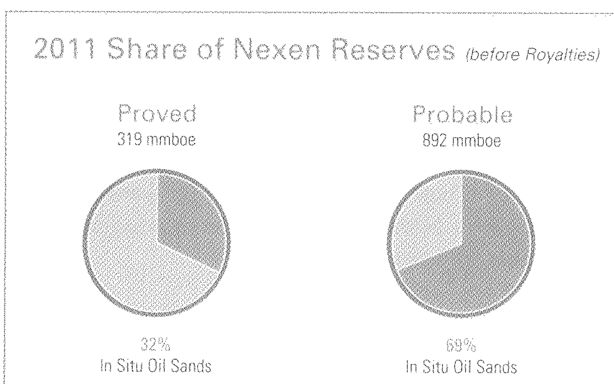
The Athabasca oil sands deposit in northeast Alberta is a key growth area for us. Our strategy is to economically develop our bitumen resource in phases to provide low-risk, stable, future growth. Our operated project at Long Lake involves integrating SAGD bitumen production with field-upgrading technology to produce PSC™ for sale, and synthetic gas, which significantly reduces our need to purchase natural gas for operations. We have a 7.23% investment in the Syncrude oil sands mining and upgrading operation, as well as significant undeveloped acreage.

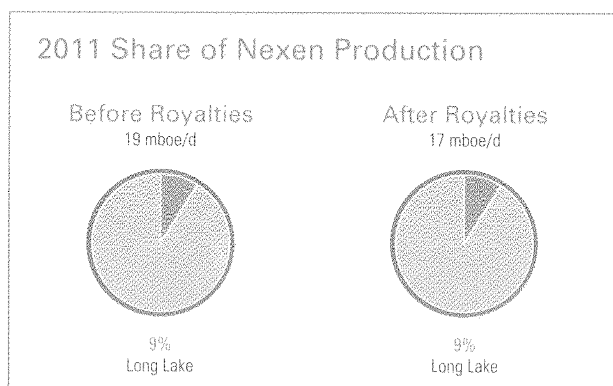
In Situ Oil Sands

In 2001, we formed a joint venture with OPTI Canada Inc. (OPTI) to develop the Long Lake lease using SAGD for in situ bitumen production and proprietary OrCrude™ technology for the first stage of upgrading the bitumen to PSC™. OPTI has the exclusive Canadian licence for the OrCrude™ technology. We acquired the exclusive right to use this technology with OPTI within approximately 160 km of Long Lake, and the right to use the technology elsewhere in Canada and the rest of the world (excluding Israel) subject to certain rights of OPTI to participate.

SAGD bitumen operations at Long Lake started mid-2008 and we began producing PSC™ from the upgrader in 2009. Early in 2009, we acquired an additional 15% interest in the Long Lake project and the joint venture lands from OPTI, increasing our ownership level to 65%. Following the acquisition, we are responsible for operating the entire project.

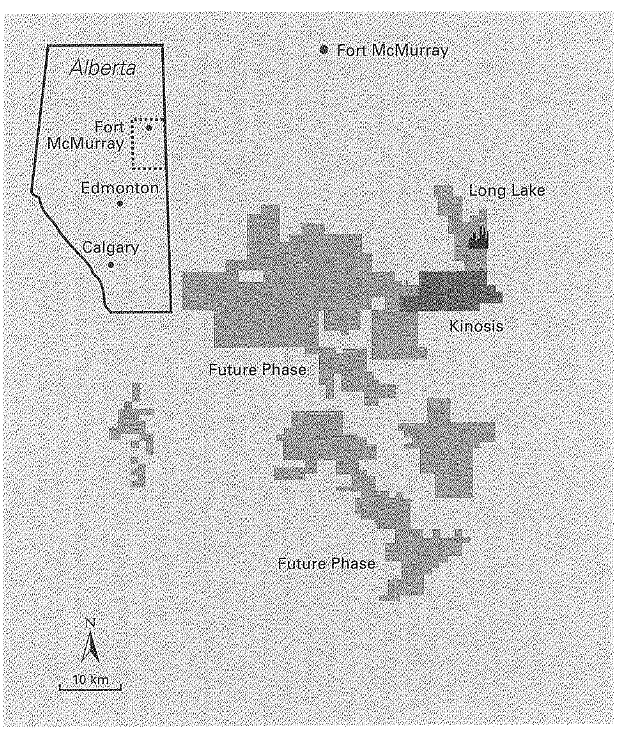
In 2011, Chinese National Offshore Oil Company acquired OPTI, which included the 35% non-operated interest in the Long Lake project and joint venture lands.





SAGD AND UPGRADER INTEGRATION

The SAGD process involves drilling two parallel horizontal wells about 16 feet apart, with horizontal portions generally between 2,300 and 3,300 feet long. Steam is injected into the shallower well, where it heats the bitumen that then flows by gravity to the deeper producing well. The OrCrude™ technology, using conventional distillation, solvent de-asphalting and thermal cracking, separates the produced bitumen into partially upgraded sour crude oil and liquid asphaltenes. By coupling the OrCrude™ process with commercially available hydrocracking and gasification technologies, sour crude oil is upgraded to light (39° API) PSC™, and the asphaltenes are converted to a low-energy, synthetic fuel gas. This gas is available as a low-cost fuel for generating steam and as a source of hydrogen for the hydrocracking process. The gas is also consumed in a dual 85 MW unit cogeneration plant to produce electricity for on-site use and sale to the provincial electricity grid. The energy conversion efficiency for our Long Lake upgrader is about 90%, compared to 75% for a typical bitumen-fed coker based plant.



Long Lake Acreage Kinosis Acreage Future Phase Acreage Upgrader

LONG LAKE AND KINOSIS PROJECTS

The Long Lake project is located approximately 40 km southeast of Fort McMurray, Alberta and operations include steam generation and water treatment facilities, cogeneration plant, SAGD operations and an onsite upgrader. Bitumen is produced from the McMurray reservoir through 90 well pairs located on 11 pads. Steam generation capacity is 228,000 bbls/d from six once-through steam boilers (46% of total capacity) and two cogeneration units (54% of total capacity).

The first several months of steam injection into a well pair largely involve heating the reservoir, followed by a ramp-up of bitumen production to peak rates over 12 to 24 months. At the start of production, steam-to-oil ratios (SORs) are high but are expected to decline as bitumen production ramps up to our target rates. We expect the SOR to be in the range of three to four over the long term.

We completed drilling 10 wells on pad 11 during 2011 with first production from the initial wells mid year. We currently produce 4,500 bbls/d (gross) from this pad and expect to produce 4,000 to 8,000 bbls/d (gross) at maturity. We expect to begin steaming the 18 well pairs on pads 12 and 13 in the spring and fall of 2012, respectively, with first oil expected three months later, thereafter ramping up over 12 to 18 months. We expect production from these two pads will contribute 11,000 to 17,000 bbls/d (gross) at maturity.

SAGD bitumen production in 2011 averaged 28,600 bbls/d gross (18,600 bbls/d net to us) and we are currently producing approximately 35,000 bbls/d gross (22,800 bbls/d net to us).

Initially, we expected to fill the upgrader from the first 11 pads that are now on-stream; however, we underestimated the impact lean zones and shales would have on production rates and steam-oil ratio (SOR). We better understand the correlation between reservoir characteristics, production and SOR, based on the range of well performance we experienced in the initial wells. This understanding allows us to target the best quality resource for development that is analogous to the wells in our initial set that are exhibiting good performance. It also confirms that our oil sands lands, including undeveloped areas on the Long Lake lease, contain attractive resource. We expect production from pads 1 to 11 to continue to increase over time from additional steam, heating through the lean zones, the ramp-up of wells as they mature, and well work-over activities.

In 2011, we adjusted our oil sands resource development strategy to accelerate increasing bitumen production for filling the upgrader. Our strategy for filling the upgrader includes:

- maintain production from the initial 10 pads;
- ramp-up of pad 11;
- start-up of pads 12 and 13, where steaming is expected in 2012;
- drilling of pads 14 and 15, which are expected to commence drilling in 2012, with first steam in 2013;
- acceleration of development of high quality resource from Kinosis (K1A);
- drilling additional core holes to identify future drilling locations on the Long Lake and Kinosis leases; and
- processing third-party sourced bitumen in the interim to enhance returns.

We are working through the engineering and regulatory processes to develop 25 to 30 well pairs on the Kinosis lease, which is located along the southern border of Long Lake (known as K1A). These wells will be drilled in bitumen resource where our extensive core hole analysis and reservoir understanding indicates that the geological characteristics, including minimal lean zones and shale barriers, are similar to our higher producing areas. Assuming regulatory approval, drilling is expected in 2012 or 2013, with first steam injection in early 2014. We expect production from these wells will contribute 15,000 to 25,000 bbls/d (gross).

To further evaluate our Long Lake and Kinosis leases for future development, a 200 well core-hole drilling program is expected to be completed this winter. This program supports our sustaining development activities to keep the Long Lake upgrader full and to begin developing the remainder of the Kinosis lease.

We expect to maintain bitumen production over the project's life, estimated in excess of 50 years, by periodically drilling additional SAGD well pairs.

Initial production of PSC™ oil from the upgrader began in 2009. The upgrader consists of the OrCrude™ unit, air separation unit, hydro-cracker, sulphur recovery facilities and gasifier. Production design capacity for the Long Lake upgrader is approximately 60,000 bbls/d (39,000 bbls/d net to us) of PSC™. We are progressing projects that will increase the operating independence between our SAGD facilities and upgrader while maintaining the benefits of integration. The facilities are able to import between 10,000 and 15,000 bbls/d of third party bitumen to process into PSC™ through the upgrader.

In 2011, we processed about 31,500 bbls/d gross (20,500 bbls/d net to us) of proprietary and third-party bitumen through the upgrader, producing 22,800 bbls/d gross (14,800 bbls/d net to us) of PSC™. Our operations include storage capacity of 430,000 bbls on site. PSC™ is transported via the Athabasca Pipeline to Hardisty and sold to customers in Canada and the US.

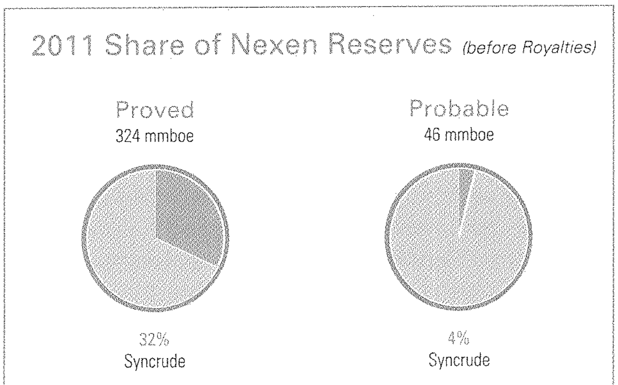
Combined SAGD, cogeneration and upgrading operating costs are expected to average about $35/bbl once we reach design capacities. We expect ongoing capital costs to average approximately $10/bbl depending on well spacing, well length and recovery factor. The full-cycle capital costs of producing and upgrading bitumen using this technology are comparable to those for surface mining and coking upgrading on a barrel-of-daily production basis.

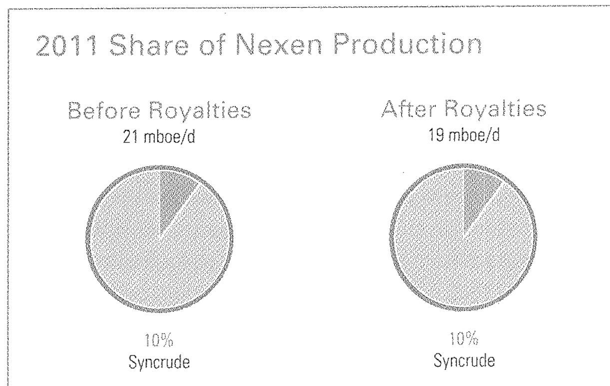
OTHER PROJECTS

Engineering and regulatory work is underway on the non-operated SAGD project at Hangingstone. We have a 25% interest in this project. Project sanctioning is expected in 2012 with first steam in 2016. Our share of production at full rates is expected to be 6,000 bbls/d.

Syncrude

We hold a 7.23% participating interest in the Syncrude joint venture. This joint venture was established in 1975 to mine shallow oil sand deposits using open-pit mining methods, extract the bitumen and upgrade it to a high-quality, light (32° API), sweet, synthetic crude oil. Syncrude's operating strategy is to develop this resource, focusing on safe, reliable and profitable operations.

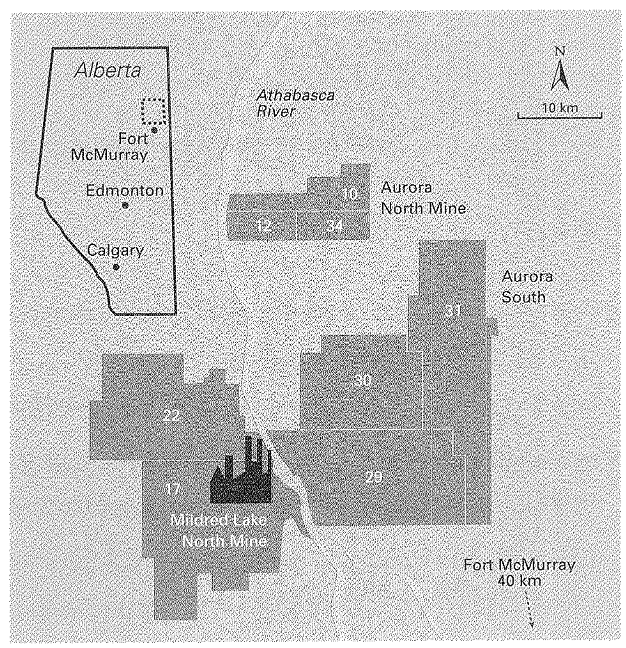




Syncrude exploits a portion of the Athabasca oil sands that contains bitumen in the unconsolidated sands of the McMurray formation. Ore bodies are buried beneath 50 to 150 feet of over-burden, have bitumen grades ranging from 4 to 14% by weight and ore-bearing sand thickness of 100 to 160 feet. Syncrude's operations are on eight leases (10, 12, 17, 22, 29, 30, 31 and 34) covering 248,300 acres, 40 km north of Fort McMurray in northeast Alberta. Syncrude currently mines oil sands at two mines: Mildred Lake North and Aurora North. Trucks and shovels are used to collect the oil sands in the open-pit mines. The oil sands are transferred for processing using a hydro-transport system.

The extraction facilities, which separate bitumen from oil sands, are capable of processing more than 310 million tons of oil sands per year and between 140 and 160 million barrels of bitumen per year depending on the average bitumen ore grade. To extract bitumen, the oil sands are mixed with water to form a slurry. Air and chemicals are added to separate bitumen from the sand grains. The process at the Mildred Lake North Mine uses hot water, steam and caustic soda to create a slurry, while at the Aurora North Mine, the oil sands are mixed with warm water. Close to 90% of the water used in operations is recycled from the upgrader and mine sites. Incremental water is drawn from the Athabasca River in accordance with existing licences.

The extracted bitumen is fed into a vacuum distillation tower and three cokers for primary upgrading, which ultimately become light, sweet, synthetic crude oil. Sulphur and coke, which are by-products of the process, are stockpiled for possible future sale.



Syncrude Leases   Upgrader

The high quality of Syncrude's synthetic crude oil allows it to be sold at prices approximating WTI. In 2011, about 45% of the synthetic crude oil was sold to refineries in Eastern Canada, 40% to those in the mid-western United States and the remaining 15% was sold to refineries in the Edmonton area. Electricity is provided to Syncrude from two generating plants on site: a 270 MW plant and an 80 MW plant.

Since operations started in 1978, Syncrude has shipped more than two billion barrels of synthetic crude oil to Edmonton by Alberta Oil Sands Pipeline Ltd. The pipeline was expanded in 2004 and 2009 to accommodate increased Syncrude production.

In 1999, the Alberta Energy and Utilities Board (AEUB) extended Syncrude's operating licence for the eight oil sands leases through to 2035. The licence permits Syncrude to mine oil sands and produce synthetic crude oil from approved development areas on the oil sands leases. The leases are automatically renewable as long as oil sands operations are ongoing or the leases are part of an approved development plan. All eight leases are included in a development plan approved by the AEUB. There were no known commercial operations on these leases prior to the start-up of operations in 1978.

In 1999, the AEUB approved an increase in Syncrude's production capacity to 465,700 bbls/d. At the end of 2001, Syncrude increased its synthetic crude oil capacity to 246,500 bbls/d with the development of the Aurora North Mine, which involved extending mining operations to a new location about 40 km north of the main Syncrude site.

The next expansion of Syncrude came on stream in 2006, increasing capacity to 360,000 bbls/d with the completion of the Stage 3 project.

Syncrude pays royalties to the Alberta government. Effective January 1, 2009, and consistent with other oil sands producers, Syncrude began paying royalties based on bitumen, rather than paying royalties calculated on fully upgraded synthetic crude oil. As a part of this conversion, the Alberta government will recapture royalties related to upgrader capital expenses of about $5 billion (gross) that were deducted against prior royalties from future production over a 25-year period. In connection with the transition to the revised Alberta royalty framework, Syncrude will continue to pay base royalty rates (being the greater of 25% of net bitumen-based revenues, or 1% of gross bitumen-based revenues) plus an incremental royalty of up to $975 million (our share $70.5 million) until December 31, 2015. The incremental royalty is subject to certain minimum bitumen production thresholds and is to be paid in six annual payments. This agreement is in lieu of the Syncrude owners converting to the Province of Alberta's new royalty framework that became effective January 1, 2009. After January 1, 2016, the rates under the new Alberta royalty framework will apply to the Syncrude project.

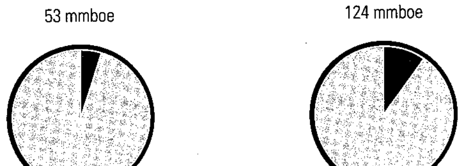
SHALE GAS

- **We reached a joint venture agreement for our northeast British Columbia shale gas play to accelerate value realization.**
- **We brought on stream a nine-well pad in the Horn River basin during the year.**
- **We expanded our shale gas exploration portfolio by acquiring a non-operated exploration interest in Poland and by testing shale gas opportunities in Colombia.**

2011 Share of Nexen Reserves *(before Royalties)*

Proved
53 mmboe

Probable
124 mmboe



5%
Canada

10%
Canada

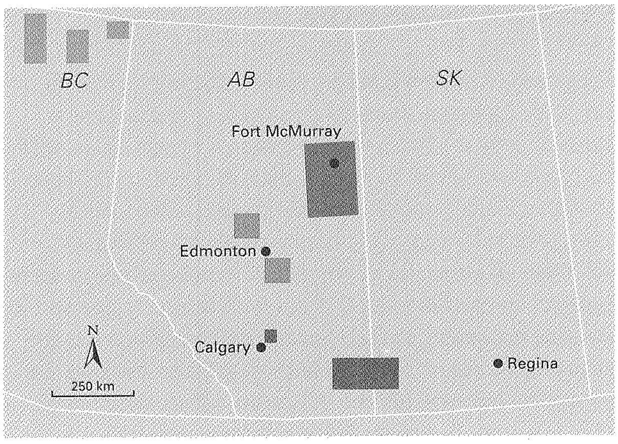
2011 Share of Nexen Production

Before Royalties
6 mboe/d

After Royalties
6 mboe/d

3%
Canada

3%
Canada



As part of our growth strategy in unconventional Canadian resource plays, we have accumulated over 300,000 acres of prospective shale gas lands in northeast British Columbia. Shale gas is natural gas produced from reservoirs composed of organic shale. The gas is stored in pore spaces and fractures, or absorbed into organic matter. Recent advances in drilling and completion technology have allowed companies to access this considerable potential resource.

Our shale gas resource allows us to take advantage of emerging markets such as growing oil sands demand and potential liquid natural gas (LNG) export opportunities off the west coast. Shale gas complements our corporate oil and gas portfolio with natural gas exposure and relatively short cycle-time projects where we control the scale and pace of development of the resource. We can match the pace of drilling and field development to forecasted economic conditions.

Our Canadian production (excluding the Athabasca oil sands) is comprised of unconventional shale gas assets in northeast British Columbia and conventional producing natural gas and CBM assets in Alberta and Saskatchewan. Prior to the sale of our heavy oil assets in July 2010, Canadian production included heavy oil volumes from east-central Alberta and west-central Saskatchewan. Proceeds from the sale were $939 million and the properties were producing approximately 15,000 boe/d.

In addition to our development of the Athabasca oil sands, our strategy for Canada is three-fold: i) significantly expand our shale gas reserves and production; ii) generate new material resource play opportunities; and iii) continue to optimize value from our conventional and CBM producing assets.

NORTHEAST BRITISH COLUMBIA

We hold approximately 300,000 acres in the Horn River, Cordova and Liard basins in northeast British Columbia. Approximately 50 to 55 mmcf/d of natural gas is generated from our shale gas properties in the Horn River. This basin is a significant shale gas play with high resource density and excellent well productivity.

In 2011, we invested $398 million progressing development of our shale gas assets at Horn River. In addition to our eight-well pad completed in 2010, we drilled and completed a nine-well pad which was brought on stream in late 2011. We began drilling an 18-well pad during the year with start-up scheduled for late 2012 and associated peak volumes expected in early 2013. Our current field processing capacity is approximately 50 to 55 mmcf/d and production from our Horn River assets is limited by this constraint. We are expanding this capacity to 175 mmcf/d in 2012 in order to process additional volumes from development of the field. Current operations are produced from 23 horizontal wells via pad developments, which minimize surface disturbances. Natural gas is compressed and dehydrated with infield facilities before export to final treating facilities via producer-owned and third-party pipelines. We hold long-term take or pay capacity on the third party pipelines and facilities.

During the year, we entered into a joint venture agreement to farm-out a 40% non-operated interest in our northeast British Columbia shale gas lands for proceeds of $700 million. The sale is expected to close in the second quarter of 2012 and Nexen will remain as operator under the joint venture.

Primary tenure in the Horn River Basin is four years and drilling activity and extensions can increase this up to 18 years. Our drilling activity to date has secured tenure for 10 years on all of our Horn River lands with extensions available of up to another three years. With the tenure secured, we are able to control the pace of field development during periods of low gas prices.

Limited gas pipeline infrastructure and processing capacity in the Horn River Basin could potentially constrain early development of the play. To ensure sufficient gathering, processing and transportation capacity for our development programs, we contracted gas pipeline capacity and associated treating capacity at the Spectra-operated Fort Nelson plant. We also entered into additional agreements that allow us to participate in regional infrastructure expansion projects.

OTHER CANADA

Conventional natural gas properties in Alberta and Saskatchewan account for 40% of our 2011 Canadian natural gas production. This production is primarily generated from our Medicine Hat/Hatton conventional fields with over 2,200 shallow gas wells on production. These properties are mature but have low decline rates and numerous infill drilling opportunities. Our future investment here is limited as a result of low natural gas prices.

Approximately 30% of our current Canadian natural gas is produced from our CBM developments in the Fort Assiniboine area of central Alberta. We began commercial operations in the Upper Mannville coals in 2005 and progressively developed opportunities on our land base with horizontal well technology. We have limited activity planned here currently as a result of lower natural gas prices.

OTHER INTERNATIONAL

During 2011, we entered into a joint venture agreement to explore 10 concessions in Poland's Paleozoic shale play. We acquired a 40% non-operated working interest in the concessions, which encompass more than two million acres. Total capital investment by Nexen for exploration activities is estimated to be approximately $100 million over the next two years. The opportunity provides shale gas exposure to growing European gas demand where prices are significantly higher than in North America. The initial exploration well was spudded in late 2011 and results are expected in 2012.

In 2011, we commenced a drilling program for four shale gas wells on two Colombian blocks (totaling 1.5 million acres). One well was drilled in late 2011 with a total depth of 5,800 feet and we expect the remainder to be spudded during 2012. We are in the early stages of shale gas exploration here and are one of the first companies to test shale gas opportunities in Colombia.

ENERGY MARKETING

Our energy marketing group's primary focus is to market Nexen's proprietary crude oil and natural gas production. We also engage in market optimization activities including the purchase and sale of third-party production which provides us with additional market intelligence and opportunities in order to obtain competitive pricing for our proprietary volumes. Our team leverages regional knowledge and holds capacity on key North American infrastructure. In addition to physical marketing, we take advantage of quality, time and location spreads to generate returns. We also use financial contracts, including futures, forwards, swaps and options to manage our business. Results of these activities are included in Corporate and Other.

RESERVES, PRODUCTION AND RELATED INFORMATION

Nexen prepares and discloses reserves estimates and other information in accordance with National Instrument 51-101—*Standards of Disclosure for Oil and Gas Activities* (NI 51-101) and with SEC requirements. Prior to 2010, Nexen and many of our Canadian peer companies relied upon a discretionary exemption from certain requirements of NI 51-101 granted by Canadian securities regulators which permitted disclosure of reserves information in accordance with SEC requirements only. In order to maintain comparability with Canadian peer companies who began disclosing their reserves under NI 51-101, we have presented our NI 51-101 reserves and related information in this Annual Report. As our reserves estimates were prepared only in accordance with SEC requirements prior to 2010, our NI 51-101 reserves information is limited to 2010 and 2011.

In order to provide comparability to non-Canadian oil and gas companies, we have also prepared reserves estimates and related information in accordance with SEC requirements, which are included in Appendix B of our AIF. Refer to the Special Note to Investors on page 58 for an explanation of differences between reserves estimates prepared under NI 51-101 and SEC requirements.

Nexen has not filed with nor included in reports to any Canadian or United States federal authority or agency with any estimates of its total proved oil or gas reserves since the beginning of 2011.

Basis of Reserves Estimates

The process of estimating reserves requires complex judgments and decision-making based on available geological, geophysical, engineering and economic data. To estimate the economically recoverable oil and gas reserves and related future net cash flows, we consider many factors and make various assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs.

We believe these factors and assumptions are reasonable based on the information available to us at the time we prepared our estimates. However, there is no guarantee that the estimated reserves will be recovered and these estimates may change substantially as additional data from ongoing development activities and production performance becomes available, and as economic conditions impacting oil and gas prices and costs change. For more information as to the risks involved in the recovery of oil and gas, see "Risk Factors" on pages 44 to 51 of our AIF.

Our estimates of reserves and future net revenue are based on internal evaluations. Reserves estimates for each property are prepared at least annually by the property's reservoir engineer and geoscientists, and by divisional management familiar with the property. Our internal reserves evaluation staff consists of over 180 individuals in multifunctional teams with relevant experience in reserves evaluation, engineering and geoscience, and over 140 of these individuals are qualified reserves evaluators for the purposes of NI 51-101. These individuals are dedicated to the development and operations of the properties evaluated and have a thorough knowledge of them. We support the technical staff with up-to-date tools for geological mapping, seismic interpretation, reservoir simulation and other technical analysis. Our reserves processes are designed to use all available information to provide accurate estimates for internal business needs and external reporting requirements. Due to the extent and expertise of our internal reserves evaluation resources, our staff's familiarity with our properties, and the controls applied to the evaluation process, we believe the reliability of our internally generated estimates of reserves and future net revenue are not materially less than would be generated by an independent qualified reserves evaluator.

Our internal qualified reserves evaluator (IQRE) is responsible for the reserves data and related disclosures. This position, required under NI 51-101, was appointed by the board in December 2003. The IQRE is a professional engineer and meets all professional and statutory requirements in regards to experience, education and professional membership associated with the role. With over 29 years of experience, the IQRE has an in-depth knowledge of reserves estimation techniques and professional guidelines, and with Canadian and SEC reserves regulations and related reporting requirements. The IQRE's primary duty includes assessing whether the reserves estimates and related disclosures have been prepared in accordance with applicable regulatory requirements.

Although we have received an exemption from the NI 51-101 requirements to have our reserves estimates independently assessed, our policy is to have at least 80% of our NI 51-101 reserves estimates either evaluated or audited annually by independent qualified reserves consultants. The section entitled "Independent Reserves Evaluation" on pages 55 to 56 of this Annual Report describes the nature and scope of the work performed by the independent consultants and their opinions from performing this work.

An Executive Reserves Committee, including our CEO, CFO and IQRE, meet with divisional reserves personnel to review the estimates and any changes from previous estimates. The board of directors has a Reserves Review Committee (Reserves Committee) to assist the board and the Audit and Conduct Review Committee to oversee the annual review of our oil and gas reserves and related disclosures. The Reserves Committee is comprised of three or more directors, the majority of whom are independent and familiar with estimating oil and gas reserves and disclosure requirements. The Reserves Committee meets with management periodically to review the reserves process, the portfolio of properties selected by management for independent assessment, results and related disclosures. The Reserves Committee appoints and meets with the IQRE and independent qualified reserves consultants to review the scope of their work, whether they have had access to sufficient information, the nature and satisfactory resolution of any material differences of opinion, and in the case of the independent qualified reserves consultants, their independence. In the event of a proposed change to the areas of responsibility of either an independent qualified reserves consultant or the IQRE, the Reserves Committee inquires whether there have been disputes between the respective party and management.

The Reserves Committee has reviewed our procedures for preparing the reserves estimates and related disclosures, and the properties selected by management for independent assessment. The Committee reviewed the information with management and met with the IQRE and the independent qualified reserves consultants. As a result, the Reserves Committee is satisfied that the internally generated reserves estimates are reliable and free of material misstatement. Based on the recommendation of the Reserves Committee, the board has approved the reserves estimates and related disclosures in this Business Overview.

We have adopted a corporate policy that prescribes the procedures and standards to be followed in the evaluation of our reserves. This policy is reviewed and amended annually as required to conform to changes in law or industry accepted evaluation practices. A copy can be found on our corporate website at www.nexeninc.com.

Reserves Estimates

The reserves data set forth on the following pages summarizes our crude oil and natural gas reserves and the net present value of the future net revenue for the reserves using forecast prices and costs. The information has been prepared in accordance with the requirements of NI 51-101. The estimates and other information has an effective date of December 31, 2011 and was prepared on February 15, 2012.

Readers should review the definitions and information contained in the "Definitions" section on pages 56 to 57 in conjunction with the following tables and notes.

Figures in this statement have been rounded to the nearest 1 mmbbls or 1 bcf. As a result, some columns may not add due to rounding.

SUMMARY OF OIL AND GAS RESERVES AS AT DECEMBER 31, 2011

Forecast Prices and Costs

	Total *(mmboe)*		Synthetic Oil *(mmbbls)*		Bitumen *(mmbbls)*		Light & Medium Oil *(mmbbls)*		Natural Gas *(bcf)*		CBM *(bcf)*		Shale Gas *(bcf)*	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada														
Proved Developed Producing	264	232	219	190	–	–	–	–	115	107	62	58	94	92
Proved Developed Non-Producing	11	10	9	8	–	–	–	–	13	12	–	–	–	–
Proved Undeveloped	454	412	415	374	–	–	–	–	–	–	7	6	225	219
Total Proved	**729**	**654**	**643**	**572**	**–**	**–**	**–**	**–**	**128**	**119**	**69**	**64**	**319**	**311**
Probable	1,072	890	277	230	661	542	–	–	33	31	24	22	742	655
Total Proved Plus Probable	**1,801**	**1,544**	**920**	**802**	**661**	**542**	**–**	**–**	**161**	**150**	**93**	**86**	**1,061**	**966**
United Kingdom														
Proved Developed Producing	147	147	–	–	–	–	141	141	30	30	–	–	–	–
Proved Developed Non-Producing	5	5	–	–	–	–	5	5	1	1	–	–	–	–
Proved Undeveloped	50	50	–	–	–	–	45	45	34	34	–	–	–	–
Total Proved	**202**	**202**	**–**	**–**	**–**	**–**	**191**	**191**	**65**	**65**	**–**	**–**	**–**	**–**
Probable	105	105	–	–	–	–	98	98	41	41	–	–	–	–
Total Proved Plus Probable	**307**	**307**	**–**	**–**	**–**	**–**	**289**	**289**	**106**	**106**	**–**	**–**	**–**	**–**
United States														
Proved Developed Producing	13	11	–	–	–	–	7	6	37	32	–	–	–	–
Proved Developed Non-Producing	12	11	–	–	–	–	4	4	46	40	–	–	–	–
Proved Undeveloped	9	8	–	–	–	–	5	4	23	21	–	–	–	–
Total Proved	**34**	**30**	**–**	**–**	**–**	**–**	**16**	**14**	**106**	**93**	**–**	**–**	**–**	**–**
Probable	82	69	–	–	–	–	65	55	101	87	–	–	–	–
Total Proved Plus Probable	**116**	**99**	**–**	**–**	**–**	**–**	**81**	**69**	**207**	**180**	**–**	**–**	**–**	**–**
Other[1]														
Proved Developed Producing	5	4	–	–	–	–	5	4	–	–	–	–	–	–
Proved Developed Non-Producing	18	16	–	–	–	–	18	16	–	–	–	–	–	–
Proved Undeveloped	20	16	–	–	–	–	20	16	–	–	–	–	–	–
Total Proved	**43**	**36**	**–**	**–**	**–**	**–**	**43**	**36**	**–**	**–**	**–**	**–**	**–**	**–**
Probable	39	31	–	–	–	–	39	31	–	–	–	–	–	–
Total Proved Plus Probable	**82**	**67**	**–**	**–**	**–**	**–**	**82**	**67**	**–**	**–**	**–**	**–**	**–**	**–**
Total Company														
Proved Developed Producing	429	394	219	190	–	–	153	151	182	169	62	58	94	92
Proved Developed Non-Producing	46	42	9	8	–	–	27	25	60	53	–	–	–	–
Proved Undeveloped	533	486	415	374	–	–	70	65	57	55	7	6	225	219
Total Proved	**1,008**	**922**	**643**	**572**	**–**	**–**	**250**	**241**	**299**	**277**	**69**	**64**	**319**	**311**
Probable	**1,298**	**1,095**	**277**	**230**	**661**	**542**	**202**	**184**	**175**	**159**	**24**	**22**	**742**	**655**
Total Proved Plus Probable	**2,306**	**2,017**	**920**	**802**	**661**	**542**	**452**	**425**	**474**	**436**	**93**	**86**	**1,061**	**966**

1 *Other includes Yemen, Nigeria and Colombia.*

At December 31, 2011, our proved plus probable reserves estimates were approximately 2.3 billion boe, of which about 1 billion boe are proved and 1.3 billion boe are probable.

Over 60% of our reserves relate to our Canadian oil sands properties. The synthetic oil reserves relate to our Long Lake and Kinosis K1A projects and our non-operated interest in Syncrude. These reserves reflect bitumen which is upgraded on site into synthetic oil and are expected to be developed and produced through the existing facilities over the next 50 years. The bitumen reserves relate to our Kinosis and Hangingstone properties, where we have not yet committed to building upgrading facilities at this time. Project planning at Kinosis and Hangingstone is underway.

Our oil sands reserves estimates and development plans are continually evolving to reflect production performance and other information. This year, as part of our reserves process, we revised our expectations of bitumen recoverability from our oil sands reservoirs. Our previous interpretation underestimated the productivity of thick clean sand, and overestimated the productivity of poorer quality sand and the effects of shale. As a result, in the high-quality areas, we increased the bitumen recovery factors. Conversely, we reduced our reserve estimates on the poor quality reservoir and removed proved acreage in lower quality areas that we are less likely to develop. This revised understanding of the reservoir productivity caused us to change our resource development strategy to fill the Long Lake upgrader. Our plans now include accelerating development of the Kinosis K1A lands, a subset of the original Kinosis lease, where extensive core hole testing indicates higher quality resource. These lands can be brought on stream sooner than other Long Lake areas as we are further advanced in the planning process.

In accordance with our reserves policy, we have our in situ oil sands properties evaluated by a third-party qualified reserves consultant, McDaniel & Associates Consultants Ltd. (McDaniel). They have extensive experience in estimating reserves for oil sands properties as they also regularly conduct evaluations for a significant number of other oil sands companies. Each year, McDaniel updates their estimates using all available technical, economic and company data including core, well, seismic, pressure and production data, our development plans, and experience they gain from evaluating other oil sands properties. McDaniel has generated proved and proved plus probable reserves estimates and revenue forecasts for each of our in situ oil sands properties from this information. McDaniel has provided an opinion that their independently-determined estimates are, in aggregate, within 10% of our estimates. We believe that the independent evaluation provides the highest level of scrutiny to our estimates as each estimate is based upon independent work and differs from an audit, which may not require the evaluator to independently generate detailed estimates that can be used for comparison.

The remainder of our reserves are widely distributed throughout our oil and gas properties around the world. Our light and medium oil reserves relate to our offshore oil and gas operations in the UK North Sea, US Gulf of Mexico, Nigeria, and onshore Colombia. Our natural gas reserves relate to our properties in the US Gulf of Mexico, UK North Sea, and southern Alberta. Our CBM reserves are located primarily in central Alberta and our shale gas reserves are located in the Horn River basin in northeast British Columbia.

All of our reserves estimates are subject to the same standard of rigor in their preparation and independent evaluation as our oil sands reserves. See the section entitled "Independent Reserves Evaluations" on pages 55 to 56 of this Annual Report.

RECONCILIATION OF CHANGES IN RESERVES

The following table provides a reconciliation of Nexen's total proved, probable and proved plus probable reserves (before royalties) as at December 31, 2011 using forecast prices and costs:

GROSS RESERVES (NEXEN RESERVES BEFORE ROYALTIES)

	Total	Canada						United Kingdom		United States		Other[1]
(Before Royalties)	*(mmboe)*	**Synthetic Oil Syncrude** *(mmbbls)*	**Synthetic Oil In Situ** *(mmbbls)*	**Bitumen[2] In Situ** *(mmbbls)*	**Natural Gas** *(bcf)*	**CBM** *(bcf)*	**Shale Gas** *(bcf)*	**Light and Medium Oil** *(mmbbls)*	**Natural Gas** *(bcf)*	**Light and Medium Oil** *(mmbbls)*	**Natural Gas** *(bcf)*	**Light and Medium Oil** *(mmbbls)*
Total Proved Reserves												
December 31, 2010	1,011	324	314	–	155	115	151	195	67	19	134	55
Discoveries	7	–	–	–	–	–	44	–	–	–	–	–
Extensions and Improved Recovery	121	8	94	–	9	–	94	1	7	–	1	1
Technical Revisions	(53)	–	(84)	–	–	(25)	40	26	4	–	2	1
Economic Factors	(2)	–	–	–	(20)	(6)	4	1	(2)	–	1	–
Production	(76)	(8)	(5)	–	(16)	(15)	(14)	(32)	(11)	(3)	(32)	(14)
December 31, 2011	**1,008**	**324**	**319**	**–**	**128**	**69**	**319**	**191**	**65**	**16**	**106**	**43**
Total Probable Reserves												
December 31, 2010	1,123	46	882	–	44	32	33	106	59	7	80	41
Discoveries	145	–	–	49	–	–	165	3	1	58	37	–
Extensions and Improved Recovery	97	8	–	–	1	–	500	–	–	1	5	4
Technical Revisions	32	–	27	–	(16)	(3)	28	11	(6)	–	(9)	(4)
Conversions[3]	(130)	(8)	(94)	–	(1)	–	–	(21)	(12)	(1)	(12)	(2)
Economic Factors	(64)	–	(67)	–	5	(5)	16	(1)	(1)	–	–	–
Reclassification to Bitumen[4]	95	–	(517)	612	–	–	–	–	–	–	–	–
December 31, 2011	**1,298**	**46**	**231**	**661**	**33**	**24**	**742**	**98**	**41**	**65**	**101**	**39**
Total Proved Plus Probable Reserves												
December 31, 2010	2,134	370	1,196	–	199	147	184	301	126	26	214	96
Discoveries	152	–	–	49	–	–	209	3	1	58	37	–
Extensions and Improved Recovery	218	16	94	–	10	–	594	1	7	1	6	5
Technical Revisions	(21)	–	(57)	–	(16)	(28)	68	37	(2)	–	(7)	(3)
Conversions[3]	(130)	(8)	(94)	–	(1)	–	–	(21)	(12)	(1)	(12)	(2)
Economic Factors	(66)	–	(67)	–	(15)	(11)	20	–	(3)	–	1	–
Reclassification to Bitumen[4]	95	–	(517)	612	–	–	–	–	–	–	–	–
Production	(76)	(8)	(5)	–	(16)	(15)	(14)	(32)	(11)	(3)	(32)	(14)
December 31, 2011	**2,306**	**370**	**550**	**661**	**161**	**93**	**1,061**	**289**	**106**	**81**	**207**	**82**

1 *Other includes Yemen, Nigeria and Colombia.*
2 *Includes reserves for which there are no definitive plans for upgrading at this time.*
3 *Technical revisions.*
4 *Economic factors.*

PROVED RESERVES

During the year, proved reserves decreased by 3 mmboe as our net additions of 73 mmboe were slightly less than production.

Discoveries of 7 mmboe at Horn River were due to the recognition of shale gas reserves in an additional shale gas zone.

Extensions and improved recovery of 121 mmboe were primarily due to recognizing Kinosis K1A reserves that are now being dedicated to the Long Lake upgrader and recognition of shale gas reserves for an 18-well Horn River pad that we expect to drill. The extensions of 94 mmboe at Kinosis K1A are included in our proved synthetic oil reserves as we are developing the area to feed the Long Lake upgrader. The remaining Kinosis lands are expected to be developed using SAGD well pairs to provide bitumen sales as we have not committed to build upgrading facilities at this time.

Technical revisions resulted in a 53 mmboe net reduction, which primarily relate to changes in our Long Lake expectations. These were partially offset by positive performance at Buzzard, Telford and Ettrick in the UK North Sea, and at our Horn River shale gas development. The 84 mmboe reduction of Long Lake synthetic oil reserves was the result of our re-assessment of the resource on the Long Lake lease which reflects a net reduction in recoverable oil in some areas. It also reflects a downgrade of proved reserves that will be deferred by a change in our development plans to dedicate Kinosis K1A to the Long Lake project. The Kinosis K1A reserves have priority since they can be brought on stream faster.

Economic factors primarily reflect lower future gas prices.

PROBABLE RESERVES

During the year, our probable reserves increased by 175 mmboe. This is due to additions of 274 mmboe, which includes our Appomattox discovery, recognition of our Hangingstone bitumen property, extensions at the Horn River shale gas properties, and 95 mmboe from reclassifying synthetic oil reserves at Kinosis to bitumen reserves. This was partially offset by reductions of 64 mmboe due to negative economic factors and conversions of 130 mmboe to proved reserves.

Discoveries of 145 mmboe include recognition of probable reserves for successes in the south fault block on our Appomattox discovery in the US Gulf of Mexico, our Hangingstone non-operated oil sands property where we are advancing plans to construct a 174-well SAGD development, the Solitaire property in the UK North Sea and recognizing shale gas reserves in a lower shale gas zone in the Horn River wells.

Extensions and improved recoveries of 97 mmboe primarily relate to additional drilling at Horn River, which is expected over the next five years.

Technical revisions resulted in a 32 mmboe increase primarily related to Long Lake, Kinosis and Horn River. Increases at Long Lake reflect the re-assessment of the resource and the reclassification of some proved reserves to probable reserves. Increases at Kinosis are a result of the re-evaluation of bitumen in place and recovery factors. Horn River reflects positive production performance supporting increased expected recoveries. Reductions are largely due to lower performance on our Canadian gas and CBM properties.

Conversions reflect probable reserves that were converted to proved reserves as a result of increased expectations of producing the reserves based on advancement of development plans, production performance and drilling results. The largest change reflects the acceleration of the Kinosis K1A area development.

Economic factors relate to changes in timing of our development plans at Long Lake and limiting the reserves to a 50-year production period and net royalty increases due to changes in price and operating costs.

Synthetic oil probable reserves reflect the reclassification of synthetic oil to bitumen as a result of our expectations regarding future development plans for Kinosis. Currently, we do not have sufficient certainty as to when we will build upgrading facilities at Kinosis and therefore, are required to classify the reserves as bitumen.

UNDEVELOPED RESERVES

The following table discloses volumes of proved undeveloped and probable undeveloped reserves that were first attributed in the last two years:

	Proved Undeveloped (Before Royalties)				Probable Undeveloped (Before Royalties)			
	2010[1]		2011		2010[1]		2011	
	First Attributed	Booked at Year-End	First Attributed	Booked at Year-End	First Attributed	Booked at Year-End	First Attributed	Booked at Year-End
Synthetic Oil—In Situ *(mmbbls)*	3	266	93	284	–	861	–	221
Synthetic Oil—Syncrude *(mmbbls)*	7	123	8	131	17	46	8	46
Bitumen *(mmbbls)*	–	–	–	–	–	–	49	661
Light and Medium Oil *(mmbbls)*	38	100	1	70	7	89	67	121
Shale Gas *(bcf)*	103	103	129	225	19	19	656	695
Natural Gas *(bcf)*	32	81	7	57	20	61	43	74
CBM *(bcf)*	12	13	–	7	3	3	–	2
Total *(mmboe)*	**73**	**522**	**125**	**533**	**31**	**1,010**	**241**	**1,178**

1 Reserves data is unavailable prior to 2010 when Nexen received an exemption from certain requirements of NI 51-101.

Approximately half of our proved reserves are undeveloped at December 31, 2011. More than 75% of these proved undeveloped reserves (PUDs) are located on our oil sands properties at Long Lake and Syncrude which will be developed as we need bitumen feedstock to supply the upgraders during their expected lives. Other PUDs relate to ongoing development activity in the UK North Sea at Buzzard, Golden Eagle, Rochelle and Telford, in Canada at our CBM and Horn River shale gas properties, and in the US Gulf of Mexico.

The in situ synthetic oil PUDs relate to reserves needed to supply the Long Lake upgrader over its expected life. They are expected to be converted to proved developed reserves over the next 28 years as we drill additional SAGD wells at Long Lake and Kinosis K1A to offset declines from the initial wells. These wells were part of the initial field development plan and included in the project investment decision. The Syncrude synthetic oil PUDs relate to Syncrude's Aurora South mine. The mine is included in the Syncrude development plan and was contemplated in the project investment decision relating to the Stage 3 expansion completed in 2005. We do not consider this mine to be developed as the extraction equipment required to access the reserves has not yet been moved to the mine site. We are proceeding with planning for the development of the mine and other mining leases and expect to commence construction in five to seven years. The Aurora South mine PUDs of 131 mmboe are expected to be converted to proved developed reserves in eight to ten years.

Our light and medium oil PUDs are primarily located in the UK North Sea, offshore West Africa, and the US Gulf of Mexico. In the UK North Sea, 45 mmboe of light and medium oil PUDs primarily relate to development projects underway at Golden Eagle and Rochelle, and ongoing development of the Buzzard, Ettrick and Blackbird fields. We have 20 mmboe of PUDs at our offshore West Africa properties, which are expected to be converted to proved developed reserves before the end of 2013 as additional facilities and development drilling is completed and tied into the production facilities that are currently being commissioned. The remaining PUDs are located in the US Gulf of Mexico.

Our shale gas PUDs are reserves related to planned development of additional pads at Horn River in northeast British Columbia, which are expected to be completed over the next two years.

Our natural gas PUDs are located in the UK North Sea and US Gulf of Mexico, and connected to our light and medium oil projects.

We expect to convert all of our PUDs to proved developed in the next four years except at Long Lake and Syncrude, which are expected to be converted to developed as required to keep the upgraders full for the next 35 years.

We expect our ongoing exploration and development activities will continue to add new PUDs.

The majority of our probable reserves are undeveloped and primarily reflects incremental synthetic oil reserves related to future drilling to keep the Long Lake upgrader full for 50 years, expected SAGD development of the bitumen resource at Kinosis, and extension of the plant life and expected higher future yields at Syncrude. These probable reserves will typically be developed in conjunction with proved reserves, but can take longer periods to develop. The remaining probable undeveloped reserves relate to ongoing pad development of Horn River, Appomattox in the Gulf of Mexico and discoveries offshore West Africa. We expect these remaining probable undeveloped reserves will be developed over the next seven years.

Our oil sands projects are large-scale developments with significantly longer production lives than conventional oil and gas projects. The proved and probable reserves associated with these projects are developed over a period of decades within the limits of facility capacity.

Net Present Value of Future Net Revenue

The estimates of future net revenues presented in the following tables do not represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material.

Future net revenue includes estimated future abandonment costs related to wells and production facilities required to produce the reserves which have been developed or are anticipated to be developed.

NET PRESENT VALUE OF FUTURE NET REVENUE BEFORE INCOME TAXES AS AT DECEMBER 31, 2011

Forecast Prices and Costs

	Before Income Taxes Discounted at (%/year) (Cdn$ millions)					Unit Value Before Tax[1] Discounted at 10%
	0%	**5%**	**10%**	**15%**	**20%**	*($/boe)*
Proved						
Canada						
Proved Developed Producing	8,676	5,090	3,395	2,483	1,937	14.64
Proved Developed Non-Producing	306	254	206	166	134	19.86
Proved Undeveloped	14,753	4,702	1,464	213	(348)	3.56
	23,735	**10,046**	**5,065**	**2,862**	**1,723**	**7.74**
United Kingdom						
Proved Developed Producing	10,213	8,951	7,981	7,226	6,626	54.47
Proved Developed Non-Producing	494	446	412	387	367	77.88
Proved Undeveloped	2,069	1,484	1,032	696	446	20.53
	12,776	**10,881**	**9,425**	**8,309**	**7,439**	**46.64**
United States						
Proved Developed Producing	(191)	(57)	23	72	103	1.98
Proved Developed Non-Producing	519	400	318	258	214	30.07
Proved Undeveloped	395	301	234	186	150	31.04
	723	**644**	**575**	**516**	**467**	**19.30**
Other[2]						
Proved Developed Producing	189	173	159	147	137	39.43
Proved Developed Non-Producing	1,052	916	807	718	646	50.33
Proved Undeveloped	959	797	670	570	489	40.75
	2,200	**1,886**	**1,636**	**1,435**	**1,272**	**44.81**
Total Company						
Proved Developed Producing	18,887	14,157	11,558	9,928	8,803	29.32
Proved Developed Non-Producing	2,371	2,016	1,743	1,529	1,361	41.22
Proved Undeveloped	18,176	7,284	3,400	1,665	737	7.00
Total Proved	**39,434**	**23,457**	**16,701**	**13,122**	**10,901**	**18.10**
Probable						
Canada	35,632	9,183	3,121	1,157	354	3.51
United Kingdom	8,811	6,652	5,250	4,292	3,602	50.35
United States	4,583	2,682	1,661	1,081	734	23.96
Other[2]	1,681	1,268	993	805	674	32.14
Total Probable	**50,707**	**19,785**	**11,025**	**7,335**	**5,364**	**10.07**
Proved Plus Probable						
Canada	59,367	19,229	8,186	4,019	2,077	5.30
United Kingdom	21,587	17,533	14,675	12,601	11,041	47.90
United States	5,306	3,326	2,236	1,597	1,201	22.56
Other[2]	3,881	3,154	2,629	2,240	1,946	39.01
Total Proved Plus Probable	**90,141**	**43,242**	**27,726**	**20,457**	**16,265**	**13.74**

1 The unit values are based on net reserve volumes.
2 Represents reserves in Yemen, Nigeria and Colombia.

NET PRESENT VALUE OF FUTURE NET REVENUE AFTER INCOME TAXES AS AT DECEMBER 31, 2011

Forecast Prices and Costs

	After Income Taxes Discounted at (%/year)[1] (Cdn$ millions)				
	0%	5%	10%	15%	20%
Proved					
Canada					
Proved Developed Producing	8,676	5,089	3,394	2,482	1,937
Proved Developed Non-Producing	306	258	212	171	138
Proved Undeveloped	11,081	3,554	1,055	48	(424)
	20,063	**8,901**	**4,661**	**2,701**	**1,651**
United Kingdom					
Proved Developed Producing	3,649	3,359	3,056	2,794	2,576
Proved Developed Non-Producing	195	177	164	154	146
Proved Undeveloped	730	546	382	255	159
	4,574	**4,082**	**3,602**	**3,203**	**2,881**
United States					
Proved Developed Producing	(191)	(57)	23	72	103
Proved Developed Non-Producing	519	400	318	258	214
Proved Undeveloped	395	301	234	186	150
	723	**644**	**575**	**516**	**467**
Other[2]					
Proved Developed Producing	136	125	115	107	99
Proved Developed Non-Producing	1,053	917	807	718	647
Proved Undeveloped	959	797	671	570	489
	2,148	**1,839**	**1,593**	**1,395**	**1,235**
Total					
Proved Developed Producing	12,270	8,516	6,588	5,455	4,715
Proved Developed Non-Producing	2,073	1,752	1,501	1,301	1,145
Proved Undeveloped	13,165	5,198	2,342	1,059	374
Total Proved	**27,508**	**15,466**	**10,431**	**7,815**	**6,234**
Probable					
Canada	26,365	6,743	2,230	759	154
United Kingdom	3,311	2,551	2,015	1,644	1,377
United States	3,100	1,844	1,157	762	524
Other[2]	1,596	1,210	952	775	650
Total Probable	**34,372**	**12,348**	**6,354**	**3,940**	**2,705**
Proved Plus Probable					
Canada	46,428	15,644	6,891	3,460	1,805
United Kingdom	7,885	6,633	5,617	4,847	4,258
United States	3,823	2,488	1,732	1,278	991
Other[2]	3,744	3,049	2,545	2,170	1,885
Total Proved Plus Probable	**61,880**	**27,814**	**16,785**	**11,755**	**8,939**

1 *We have estimated the after-tax net present value after including the existing tax positions at a corporate level of aggregation. As a result, our after-tax economics are not estimated on a project stand-alone basis and therefore the valuation of individual properties on a stand-alone basis may differ significantly from our estimates. We also have not included costs related to corporate activities such as financing and corporate G&A associated with administration and planning activities.*

2 *Represents reserves in Yemen, Nigeria and Colombia.*

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS AT DECEMBER 31, 2011

Forecast Prices and Costs

(Cdn$ millions)	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Proved Reserves								
Canada	88,157	9,962	46,392	7,177	891	23,735	3,672	20,063
United Kingdom	21,073	18	5,173	1,608	1,498	12,776	8,202	4,574
United States	2,179	248	419	210	579	723	–	723
Other[1]	4,361	624	845	552	140	2,200	52	2,148
Total	**115,770**	**10,852**	**52,829**	**9,547**	**3,108**	**39,434**	**11,926**	**27,508**
Proved Plus Probable Reserves								
Canada	214,026	31,928	98,656	22,496	1,579	59,367	12,939	46,428
United Kingdom	32,244	43	7,159	1,825	1,630	21,587	13,702	7,885
United States	10,421	1,540	1,181	1,634	760	5,306	1,483	3,823
Other[1]	8,448	1,504	1,306	1,518	239	3,881	137	3,744
Total	**265,139**	**35,015**	**108,302**	**27,473**	**4,208**	**90,141**	**28,261**	**61,880**

1 *Represents reserves in Yemen, Nigeria and Colombia.*

TOTAL FUTURE NET REVENUE BY PRODUCT GROUP AS AT DECEMBER 31, 2011

Forecast Prices and Costs

	Future Net Revenue Before Income Taxes (discounted at 10%/year)	Unit Value Before Income Taxes[1] (discounted at 10%/year)	
	(Cdn$ millions)	*($/bbl)*	*($/mcf)*
Proved Reserves			
Light and Medium Oil[2]	11,673	46.16	–
Synthetic Oil	4,899	8.57	–
Natural Gas	46	–	0.22
CBM	59	–	0.93
Shale Gas	24	–	0.08
Proved Plus Probable Reserves			
Light and Medium Oil[2]	19,596	44.25	–
Synthetic Oil	6,848	8.54	–
Bitumen	700	12.63	–
Natural Gas	77	–	0.23
CBM	93	–	1.09
Shale Gas	412	–	0.43

1 *Unit values are based upon net reserves volumes.*
2 *Including solution gas and other by-products.*

FORECAST PRICES AND COSTS USED IN ESTIMATES

NI 51-101 requires that the forecast prices and costs used in preparation of the reserves estimates represent a reasonable outlook of the future. The pricing and cost assumptions were determined with reference to benchmark and inflationary forecasts obtained from a number of qualified reserves evaluation firms and other information sources. Field pricing was estimated by applying typical adjustments such as quality and transportation costs to a benchmark price.

The forecast cost and price assumptions used in the reserve estimates are summarized in the following tables:

PRICING AND INFLATION RATE ASSUMPTIONS AS AT DECEMBER 31, 2011
Forecast Prices and Costs

	Light and Medium Oil			Synthetic Crude Oil	Natural Gas			Inflation Rates	Exchange Rate
	WTI Cushing Oklahoma	**Brent**	**Vasconia**	**MSW Edmonton**	**Henry Hub Gas Price**	**National Balancing Pt**	**AECO Gas Price**		
Year	*(US$/bbl)*	*(US$/bbl)*	*(US$/bbl)*	*(Cdn$/bbl)*	*(US$/mmbtu)*	*(£/therm)*	*(Cdn$/GJ)*	*%/Year*	*(US$/Cdn$)*
Historical									
2011	95.26	111.38	107.65	96.78	4.05	0.56	3.47	n/a	1.02
Forecast									
2012	95	105	102	97	4.15	0.62	3.50	2.0	0.95
2013	95	105	97	94	4.70	0.66	4.00	2.0	1.00
2014	95	100	94	94	5.25	0.69	4.50	2.0	1.00
2015	100	100	95	96	5.80	0.69	5.00	2.0	1.00
2016	100	100	97	99	6.25	0.69	5.40	2.0	1.00
Thereafter	2% infl.	2% infl.	2% infl.	2% infl.	2% infl.	2% infl.	2% infl.	2% infl.	1.00

The forecast price and cost assumptions assume the continuance of current laws and regulations. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. These assumptions may differ from internal assumptions that are used for project economics and planning purposes.

Weighted average realized prices for the year ended December 31, 2011 are summarized in the section entitled Production History on pages 54 to 55.

SUMMARY OF OIL AND GAS FUTURE DEVELOPMENT COSTS AS AT DECEMBER 31, 2011
Forecast Prices and Costs

	Total Proved Reserves					Total Proved Plus Probable Reserves				
(Cdn$ millions)	**Canada**	**United Kingdom**	**United States**	**Other**	**Total**	**Canada**	**United Kingdom**	**United States**	**Other**	**Total**
2012	860	714	50	384	2,008	914	793	73	384	2,164
2013	815	406	22	126	1,369	1,078	481	38	126	1,723
2014	328	303	68	39	738	1,159	339	197	194	1,889
2015	201	141	35	3	380	1,104	169	218	318	1,809
2016	127	44	20	–	191	601	43	222	361	1,227
Thereafter	4,846	–	15	–	4,861	17,640	–	886	135	18,661
Total (undiscounted)	7,177	1,608	210	552	9,547	22,496	1,825	1,634	1,518	27,473

We believe internally generated cash flow from operations, supplemented if required by existing credit facilities, access to debt and equity markets, and future asset dispositions, are sufficient to fund future growth plans. There can be no guarantee that funds will be available in the future or that we will allocate funding to develop all of the reserves. Failure to develop those reserves would have a negative impact on future production and cash flow and could result in negative revisions to our reserves.

Interest and other costs of external funding requirements are not included in the future net revenue estimates. Since our investment decisions are based on expected returns on investment, interest or other funding costs do not directly affect the reserves estimates. We do not expect that interest or other costs of external funding would make the development of any property uneconomic.

Other Oil and Gas Information

PRODUCING AND NON-PRODUCING WELLS

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2011:

	Oil		Gas		Total	
(number of wells)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Producing Wells						
United Kingdom	63	31	–	–	63	31
Canada—Alberta	17	6	1,470	1,242	1,487	1,248
Canada—British Columbia	–	–	27	27	27	27
Canada—Saskatchewan	–	–	1,322	1,259	1,322	1,259
Canada—Oil Sands	90	58	–	–	90	58
US—Alabama	12	–	6	–	18	–
US—Louisiana	51	40	50	40	101	80
US—Texas	15	3	9	2	24	5
Yemen	56	56	–	–	56	56
Colombia	111	11	–	–	111	11
Total	**415**	**205**	**2,884**	**2,570**	**3,299**	**2,775**
Non-Producing Wells						
United Kingdom	15	8	–	–	15	8
Canada—Alberta	2	2	295	172	297	174
Canada—British Columbia	–	–	22	22	22	22
Canada—Saskatchewan	1	1	9	7	10	8
Canada—Oil Sands	18	12	21	14	39	26
US—Alabama	11	–	2	–	13	–
US—Louisiana	49	34	63	64	112	98
US—Texas	19	1	33	2	52	3
Yemen	48	48	1	1	49	49
Nigeria	25	5	–	–	25	5
Total	**188**	**111**	**446**	**282**	**634**	**393**

PROPERTIES WITH NO ATTRIBUTED RESERVES

The following table sets out the unproved properties in which we have an interest for which we have no attributed reserves, as at December 31, 2011:

(thousands of acres)	**Gross**	**Net**	**To Expire Within One Year** [1]
United Kingdom	1,579	971	25
Canada	1,806	997	197
United States	1,206	564	77
Yemen [2]	511	511	–
Colombia [3]	1,617	1,531	–
Nigeria [2,4]	230	41	–
Poland	2,258	903	–
Norway	188	90	–
Total	**9,395**	**5,608**	**299**

1 Net acres of unproved properties for which we expect our rights to explore, develop and exploit to expire within one year.

2 The acreage is covered by production-sharing contracts.

3 The acreage is covered by an association contract.

4 The acreage is covered by joint venture agreements.

Our properties with no attributed reserves are geographically and technically diverse and require a variety of capital investment activities ranging from seismic acquisition to drilling and development in order to explore and potentially prove-up reserves. Some properties are in the early evaluation stages of exploration while others have discovered hydrocarbons. Our property portfolio is continuously reviewed on the basis of prospectivity, risk, and economics to prioritize the opportunities we choose to invest in and develop. As a result, some properties are prioritized for capital investment, while others are held as inactive pending the results of future reviews, or sold, traded, relinquished, or allowed to expire.

The practice of requiring companies to pledge to carry out work commitments such as seismic acquisition, geophysical studies or exploration drilling in exchange for property exploration and development rights is common particularly in undeveloped or unexplored areas. We estimate work commitments of about $100 million to retain the related properties located in offshore UK, offshore Nigeria and Poland over the next three years. We continue to assess, and if warranted, explore these lands prior to their expiry. There are no significant factors or uncertainties associated with the economic viability and development of these properties other than those discussed generally in the "Risk Factors" section on pages 44 to 51 of our AIF.

ADDITIONAL INFORMATION CONCERNING ABANDONMENT AND RECLAMATION COSTS

We are required to remove or remedy the effect of our activities at our present and future operating sites by dismantling and removing production facilities and remediating the related damage. In estimating our future abandonment and reclamation costs (A&R costs), we make estimates and judgments on activities that will occur many years from now. In estimating A&R costs, we consider many factors including existing contracts, regulations, A&R techniques, industry conditions and past experience. As such, factors are constantly changing and our estimates are uncertain.

As of December 31, 2011, our expected undiscounted A&R costs are $3,108 million ($1,038 million, discounted at 10%) for proved reserves, including $159 million of costs to be incurred within the next three financial years. These costs relate to approximately 3,168 existing net wells and additional wells planned to be drilled in the future to access proved reserves.

The total amount of A&R costs in our proved reserves estimate is higher than the asset retirement obligation on our balance sheet primarily due to retirement costs related to planned future capital expenditures. These future obligations are relevant for determining the economic viability of our reserves but do not constitute an existing liability in our financial statements as the wells or facilities potentially giving rise to these costs have not yet been constructed.

TAX HORIZON

We are currently cash taxable in the UK, Colombia and Yemen. In Canada, the US and Nigeria, our estimated tax horizon is beyond five years.

COSTS INCURRED

The following table summarizes the costs incurred in our oil and gas activities for the year ended December 31, 2011:

		Oil and Gas			
(Cdn$ millions)	**Total Oil and Gas**	**Canada**	**United Kingdom**	**United States**	**Other[1]**
Year Ended December 31, 2011					
Property Acquisition Costs					
Proved	–	–	–	–	–
Unproved	17	3	12	2	–
Exploration Costs	902	505	87	154	156
Development Costs	2,123	656	644	229	594
Total Costs Incurred[2]	**3,042**	**1,164**	**743**	**385**	**750**

1 *Represents costs incurred in Yemen, Nigeria, Norway, Poland and Colombia.*

2 *Total costs incurred include asset retirement costs of $526 million and excludes costs related to chemicals, energy marketing, corporate and other of $59 million.*

EXPLORATION AND DEVELOPMENT ACTIVITIES

The following table sets forth the gross and net exploratory and development wells that were completed during 2011:

Exploratory Wells

	Oil Wells		Gas Wells		Service Wells[1]		Stratigraphic Wells		Dry Holes		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United Kingdom	–	–	–	–	–	–	–	–	5.0	3.9	5.0	3.9
Canada	3.0	3.0	10.0	10.0	–	–	–	–	–	–	13.0	13.0
United States	–	–	–	–	–	–	–	–	–	–	–	–
Other[2]	–	–	–	–	–	–	–	–	1.0	0.5	1.0	0.5
Total	**3.0**	**3.0**	**10.0**	**10.0**	**–**	**–**	**–**	**–**	**6.0**	**4.4**	**19.0**	**17.4**

Development Wells

	Oil Wells		Gas Wells		Service Wells[1]		Stratigraphic Wells		Dry Holes		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United Kingdom	4.0	1.7	–	–	–	–	–	–	2.0	0.9	6.0	2.6
Canada	18.0	11.7	33.0	16.8	47.0	30.1	142.0	75.9	–	–	240.0	134.6
United States	–	–	–	–	–	–	–	–	–	–	–	–
Other[2]	8.0	5.6	–	–	1.0	0.2	–	–	–	–	9.0	5.8
Total	**30.0**	**19.0**	**33.0**	**16.8**	**48.0**	**30.3**	**142.0**	**75.9**	**2.0**	**0.9**	**255.0**	**143.0**

Total Wells

	Oil Wells		Gas Wells		Service Wells[1]		Stratigraphic Wells		Dry Holes		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United Kingdom	4.0	1.7	–	–	–	–	–	–	7.0	4.8	11.0	6.5
Canada	21.0	14.7	43.0	26.8	47.0	30.1	142.0	75.9	–	–	253.0	147.6
United States	–	–	–	–	–	–	–	–	–	–	–	–
Other[2]	8.0	5.6	–	–	1.0	0.2	–	–	1.0	0.5	10.0	6.3
Total	**33.0**	**22.0**	**43.0**	**26.8**	**48.0**	**30.3**	**142.0**	**75.9**	**8.0**	**5.3**	**274.0**	**160.4**

1 *Service wells include injector wells, waste water wells and other wells not intended to produce oil and gas.*
2 *Represents activity in Yemen, Nigeria, Norway and Colombia.*

PRODUCTION ESTIMATES

The following table sets out our estimated production for 2012 from our estimates of gross proved reserves and gross probable reserves:

	Total *(mmboe)*	Synthetic Oil *(mmbbls)*	Light and Medium Oil *(mmbbls)*				Natural Gas *(bcf)*				CBM *(bcf)*	Shale Gas *(bcf)*
(Before Royalties)	Company	Canada	United Kingdom	United States	Other[1]	Total	Canada	United Kingdom	United States	Total	Canada	Canada
Total Proved	72	13	33	3	8	44	16	13	22	51	12	21
Total Probable	8	1	3	–	3	6	–	4	5	9	1	–
Total Proved Plus Probable	80	14	36	3	11	50	16	17	27	60	13	21

1 *Represents production in Yemen and Colombia.*

Our Buzzard field in the UK is the only field which accounts for more than 20% of our estimated 2012 production volumes. Our reserves analysis estimates the field will produce 27 mmboe of primarily light and medium oil on a proved plus probable basis for the year ended December 31, 2012.

PRODUCTION HISTORY

The following table summarizes certain information in respect of our production, prices received, royalties paid, production costs and resulting netback for the year ended December 31, 2011:

Cash Netback[1]		**Quarters—2011**			**Total Year**
(Cdn$, unless noted)	**1st**	**2nd**	**3rd**	**4th**	**2011**
United Kingdom					
Crude Oil:					
Sales *(mbbls/d)*	104.2	73.3	75.2	92.7	86.3
Price Received *($/bbl)*	99.97	110.67	107.58	110.46	106.76
Natural Gas:					
Sales *(mmcf/d)*	36	37	26	22	30
Price Received *($/mcf)*	7.29	8.20	7.28	6.52	7.42
Total Sales Volume *(mmboe/d)*	110.2	79.5	79.5	96.4	91.3
Price Received *($/boe)*	96.91	105.87	104.13	107.70	103.32
Royalties and Other *($/boe)*	–	0.11	0.82	0.54	0.36
Operating Costs *($/boe)*	9.85	8.48	14.46	9.99	10.60
In-country Taxes *($/boe)*	42.46	42.76	41.00	43.24	42.41
Netback *($/boe)*	44.60	54.52	47.85	53.93	**49.95**
Canada—Natural Gas					
Sales *(mmcf/d)*	97	85	79	112	93
Price Received *($/mcf)*	3.65	3.62	3.51	3.08	3.44
Royalties and Other *($/mcf)*	0.28	0.24	0.27	0.17	0.23
Operating Costs *($/mcf)*	1.70	1.54	1.65	1.70	1.65
Netback[2] *($/mcf)*	1.67	1.84	1.59	1.21	**1.56**
Canada—Oil Sands In Situ[3]					
Sales *(mbbls/d)*	12.9	14.3	11.8	16.7	13.9
Price Received *($/bbl)*	89.82	108.78	94.15	97.28	98.33
Royalties and Other *($/bbl)*	3.58	6.05	5.07	5.29	5.05
Operating Costs *($/bbl)*	89.43	95.34	85.42	67.41	83.44
Netback *($/bbl)*	(3.19)	7.39	3.66	24.58	**9.84**
Canada—Oil Sands Syncrude					
Sales *(mbbls/d)*	23.2	20.4	21.6	18.2	20.8
Price Received *($/bbl)*	94.60	111.79	97.65	104.32	101.73
Royalties and Other *($/bbl)*	4.30	13.82	4.65	10.59	8.10
Operating Costs *($/bbl)*	36.11	39.98	37.10	38.24	37.78
Netback *($/bbl)*	54.19	57.99	55.90	55.49	**55.85**

1 *Netbacks are defined as average sales price less royalties and other, operating costs, and in-country taxes in Yemen and the United Kingdom. The unit values are based on gross reserve volumes.*

2 *Average sales price, royalties, and operating costs for Canadian CBM and shale gas are included in Canada—Natural Gas.*

3 *Excludes activities related to third-party bitumen purchased, processed and sold. Sales volumes and amounts relate to PSC™ sales made to third parties during the period.*

Cash Netback[1]	Quarters—2011				Total Year
(Cdn$, unless noted)	1st	2nd	3rd	4th	2011
United States					
Crude Oil:					
Sales *(mbbls/d)*	9.2	8.9	7.7	7.2	8.2
Price Received *($/bbl)*	91.39	101.89	96.00	110.89	99.65
Natural Gas:					
Sales *(mmcf/d)*	103	96	81	66	86
Price Received *($/mcf)*	4.36	4.42	4.27	3.59	4.21
Total Sales Volume *(mboe/d)*	26.3	24.9	21.2	18.2	22.6
Price Received *($/boe)*	48.91	53.56	50.72	57.27	52.31
Royalties and Other *($/boe)*	5.65	6.11	5.63	3.31	5.30
Operating Costs *($/boe)*	10.43	10.72	11.18	16.73	11.96
Netback *($/boe)*	32.83	36.73	33.91	37.23	**35.05**
Yemen					
Sales *(mbbls/d)*	34.9	39.3	31.8	27.8	33.4
Price Received *($/bbl)*	101.57	111.77	107.98	111.14	108.11
Royalties and Other *($/bbl)*	46.98	52.26	49.72	45.94	48.97
Operating Costs *($/bbl)*	10.75	9.18	13.20	20.48	12.92
In-country Taxes *($/bbl)*	13.48	16.26	15.49	14.03	14.89
Netback *($/bbl)*	30.36	34.07	29.57	30.69	**31.33**
Other Countries					
Sales *(mbbls/d)*	1.8	1.7	1.6	1.6	1.7
Price Received *($/bbl)*	93.52	106.57	101.28	110.46	102.71
Royalties and Other *($/bbl)*	6.22	6.93	6.57	7.03	6.68
Operating Costs *($/bbl)*	8.11	10.19	8.58	9.65	9.11
Netback *($/bbl)*	79.19	89.45	86.13	93.78	**86.92**
Company-Wide					
Oil and Gas Sales *(mboe/d)*	225.5	194.3	180.7	197.6	199.2
Price Received *($/boe)*	85.98	95.31	91.06	94.11	91.46
Royalties and Other *($/boe)*	8.74	13.47	10.83	8.62	10.34
Operating and Other Costs *($/boe)*	17.32	18.68	20.80	19.56	19.00
In-country Taxes *($/boe)*	22.84	20.78	20.76	23.08	21.92
Netback *($/boe)*	37.08	42.38	38.67	42.85	**40.20**

1 *Netbacks are defined as average sales price less royalties and other, operating costs, and in-country taxes in Yemen. The unit values are based on gross reserve volumes.*

INDEPENDENT RESERVES EVALUATIONS

The following provides an overview of the nature and scope of the independent evaluations and audits that we have had performed on our reserves estimates. An independent evaluation is a process whereby we request a third-party engineering firm to prepare an estimate of our proved and probable reserves by assessing and interpreting all available data on a reservoir. An independent audit is a process whereby we request a third-party engineering firm to prepare an estimate of our reserves by reviewing our estimates, supporting working papers and other data as they feel is necessary. The primary difference is that an evaluator uses the reservoir data to prepare their own estimate, whereas an auditor reviews our work and estimate in preparing their estimate.

We have at least 80% of our NI 51-101 reserves estimates either evaluated or audited annually by independent qualified reserves consultants using applicable NI 51-101 requirements. Given that reserves estimates are based on numerous assumptions, interpretations and judgments, differences frequently arise between the estimates prepared by different qualified estimators. When the initial estimate of proved reserves on the portfolio of properties differs by greater than 10%, we work with the independent reserves consultant to reconcile the difference to within 10%. Estimates pertaining to individual properties within the portfolio may differ by more than 10%, either positively or negatively. We do not attempt to resolve each property to within 10% as it would be time and cost prohibitive given the number of wells in which we have an interest. We follow a similar process in connection with our probable reserves estimates whereby we reconcile any differences on a proved plus probable basis to be within 10%, and as such, probable reserves for individual properties within the portfolio may differ significantly.

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

We do not place any limitations on the work to be performed. Upon completion of their work, the independent reserves consultant issues an opinion as to whether our estimates of the proved and probable reserves for that portfolio of properties is, in aggregate, reasonable relative to the criteria set forth in NI 51-101.

For our reserves estimates prepared in accordance with NI 51-101 requirements, we engaged three independent reserves consultants to evaluate or audit our properties:

- We engaged DeGolyer and MacNaughton (D&M) to evaluate 100% of our proved and proved plus probable reserves in the UK North Sea, Nigeria, and our Canadian shale gas properties. D&M provided an opinion that the proved and proved plus probable reserves for the reviewed properties are reasonable because, in aggregate, they are within 10% of their estimates.
- We engaged McDaniel & Associates Consultants Ltd. (McDaniel) to evaluate approximately 100% of our proved and our proved plus probable reserves for our in situ oil sands properties. McDaniel provided an opinion that the proved and proved plus probable reserves for the reviewed properties are reasonable because, in aggregate, they are within 10% of their estimates.
- We also engaged McDaniel to audit 100% of our proved and proved plus probable reserves for our Syncrude interest. McDaniel provided an opinion that the proved and proved plus probable reserves estimates for the Syncrude property are reasonable because they expect it would be within 10% of their own estimate were they to perform their own detailed evaluation of the property.
- We engaged Ryder Scott Company (Ryder Scott) to evaluate 94% of our proved and 97% of our proved plus probable US Gulf of Mexico properties. Ryder Scott provided an opinion that the proved and proved plus probable reserves for the reviewed properties are reasonable because, in aggregate, they are within 10% of their estimates.

In aggregate our independent reserves consultants evaluated or audited 96% of our proved and 98% of our proved plus probable reserves.

For each opinion, an opinion letter has been prepared, which summarizes the work undertaken, the assumptions, data, methods and procedures they used and concludes with their opinion. These reports have been filed on SEDAR at www.sedar.com.

DEFINITIONS

In the foregoing reserves discussion the following definitions and notes are applicable:

1. "Gross" means:
   (a) in relation to our interest in production or reserves, our "company gross reserves", which are our working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest to us;
   (b) in relation to wells, the total number of wells in which we have an interest; and
   (c) in relation to properties, the total area of properties in which we have an interest.

2. "Net" means:
   (a) in relation to our interest in production or reserves, our working interest (operating and non-operating) share after deduction of royalties obligations, plus our royalty interests in production or reserves;
   (b) in relation to our interest in wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and
   (c) in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest we owned.

   The crude oil, natural gas liquids and natural gas reserves estimates presented in this Statement are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below:

3. Reserves Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on:

(a) analysis of drilling, geological, geophysical and engineering data;
(b) the use of established technology; and
(c) specified economic conditions, which are generally accepted as being reasonable.

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

(a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
(b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the classification of reserves are provided in the Canadian Oil and Gas Evaluation (COGE) Handbook.

4. Development and Production Status

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories.

(a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

   Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

   Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in and the date of resumption of production is unknown.

(b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable) to which they are assigned.

   In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

LEVELS OF CERTAINTY FOR REPORTED RESERVES

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates are prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

Special Note to Investors

Investors should note the following fundamental differences between reserves estimates and related disclosures prepared in accordance with SEC requirements and those prepared in accordance with NI 51-101:

- SEC reserves estimates are based upon different reserves definitions and are prepared in accordance with generally recognized industry practices in the US, whereas NI 51-101 reserves are based on definitions and standards promulgated by the COGE Handbook and generally recognized industry practices in Canada;
- SEC reserves definitions differ from NI 51-101 in areas such as the use of reliable technology, areal extent around a drilled location, quantities below the lowest known oil and quantities across an undrilled fault block;
- the SEC mandates disclosure of proved reserves and the Standardized Measure of Discounted Future Net Cash Flows and Changes Therein calculated using the year's monthly average prices and costs held constant, whereas NI 51-101 requires disclosure of reserves and related future net revenues using forecast prices and costs;
- the SEC mandates disclosure of reserves by geographic area, whereas NI 51-101 requires disclosure of reserves by additional categories and product types;
- the SEC does not require the disclosure of future net revenue of proved and proved plus probable reserves using forecast pricing at various discount rates;
- the SEC requires future development costs to be estimated using existing conditions held constant, whereas NI 51-101 requires estimation using forecast conditions;
- the SEC does not require the validation of reserves estimates by independent qualified reserves evaluators or auditors, whereas, without an exemption, NI 51-101 requires issuers to engage such evaluators or auditors to evaluate, audit or review their reserves and related future net revenue; and
- the SEC does not allow proved and probable reserves estimates to be aggregated, whereas NI 51-101 requires issuers to aggregate the estimates.

The foregoing is a general description of the principal differences only. The differences between SEC requirements and NI 51-101 may be material for certain properties.

ENVIRONMENTAL AND REGULATORY MATTERS

Government and Environmental Regulations

Our operations are subject to various levels of government controls and regulations in the countries where we operate. These laws and regulations include matters relating to exploration, production practices, occupational health and safety, environmental protection, midstream and marketing activities. These laws and regulations may increase the cost of doing business and, accordingly, affect profitability. We participate in many industry and professional associations through which our interests in new regulations and legislation are represented, and we monitor the progress of proposed regulatory and legislative amendments.

Laws and regulations change frequently and sometimes unpredictably. Regulatory complexity and stringency has increased over the past several years, as has the cost of compliance. Based on this trend, it is reasonably likely that the costs of compliance will continue to increase. We consider compliance with these regulations a necessary and manageable part of our business. We have been able to plan for and manage the increasing regulatory requirements without materially changing our business strategies or incurring significant or unreimbursed expenditures, though we are unable to predict the impact of future changes in compliance requirements on costs. We do not expect that the effect of these laws and regulations on our operations will be materially different than they would for any other oil and gas company of similar size and financial strength. We believe our operations comply, in all material respects, with applicable laws and regulations in the various jurisdictions where we operate.

The types of laws and regulations that affect our business most significantly fall into two categories: i) Operational and ii) Health, Safety and Environmental.

OPERATIONAL REGULATIONS

Our oil and gas exploration and production activities are subject to various international, federal, state, provincial, territorial and local laws and regulations. Those laws and regulations affect a number of operational activities, including:

- land access;
- acquisition of seismic data;
- location of wells;
- drilling, completion and well servicing;
- transportation, storage and disposal of waste products arising from oil and gas operations;
- land restoration and well abandonment;
- pricing policies;
- royalties;
- various taxes and levies including income tax; and
- foreign trade and investment.

The implications of these laws and regulations to our business include direct costs in the form of tariffs, fees, taxes, rent and royalties and other direct charges measured by the type, region or intensity of activity. Indirect costs also arise from restricted access to certain areas of operation; restrictions on the type, frequency or conduct of permitted oilfield operations; limitations on production rates from certain oil and gas wells; forced pooling of oil and gas interests with third parties; changes in drill spacing units or well densities; infrastructure development; satisfaction of local content obligations for international projects; carried government participation in certain projects; and community consultation.

US Gulf of Mexico

Throughout the second half of 2010, the Bureau of Ocean Energy Management, Regulation and Enforcement (formerly the Minerals Management Service of the Department of the Interior) released new regulations governing drilling activities in the Gulf of Mexico. These regulations contain, among other things, increased requirements for wellbore integrity, blow-out prevention, well control equipment, personnel training, rig safety and spill response. We believe that the rigorous health, safety and environmental processes that we apply to our existing offshore operating activities enable us to satisfy these new regulatory obligations. Despite our ability to meet the new regulations, the new processes implemented by the Bureau to administer these regulations have delayed the permitting process, which could add to costs and longer cycle times for our Gulf of Mexico exploration and development drilling activities.

HEALTH, SAFETY AND ENVIRONMENTAL REGULATIONS

Our oil and gas operations are subject to various international, federal, state, provincial, territorial and local laws and regulations designed to regulate the impact of human activity on the natural environment and the safety of our worksites. These laws and regulations relate to:

- the types and quantities of substances and waste materials that can be released into the environment;
- use or removal of natural resources (such as water and timber) in exploration and production activities;
- abandonment, reclamation and remediation of worksites (including sites of former operations);
- development of emergency and community response plans; and
- implementation of safe work practices for employees and contractors.

We are committed to operating within these laws and regulations and to conducting our business in a safe and environmentally responsible manner.

Environmental regulations continue to evolve and are becoming more complex. To reduce our risk of non-compliance with these laws, we apply internal tools and processes, and industry standards and best practices that meet or exceed our legal obligations. Where regulations do not exist, or where we consider them to be insufficiently developed, we observe Canadian standards or internationally accepted industry environmental management practices.

Our Health, Safety, Environment and Social Responsibility group (HSE&SR) helps ensure our worldwide operations are conducted in a safe, ethical and socially responsible manner. Our HSE&SR practices are reported to our board of directors throughout the year. Nexen's overall HSE&SR program is guided by our corporate HSE&SR management system that incorporates the continual improvement model of Plan, Do, Check, Act and our own 12 guiding elements for divisional performance. For more information on Nexen's HSE&SR governance model, refer to the Responsible Development section of our website as well as our sustainability report, both available at www.nexeninc.com.

Our performance against this system is reviewed by an external auditor every three years, and we have been recognized by the *Goldman Sachs SUSTAIN Report and Dow Jones Sustainability Index* (North America) as a sustainability leader. Our progress is publicly reported in our sustainability report.

Environmental and Social Responsibilities

Environmental and social responsibility has become an increasingly significant measurement of corporate performance by governments, investors and the public. The oil and gas industry is being challenged to improve its response to the effects of climate change, embrace responsible operating practices, including the preservation of water, land, air and biodiversity, and consult and invest in the communities it relies upon to do business. The level of regulation associated with these issues varies considerably throughout the jurisdictions in which we operate. Based on the current trend, it is reasonably likely that our regulatory obligations and the associated cost of compliance will increase. Due to the uncertainty surrounding the future implementation of regulations, we are unable to estimate our costs of compliance in the future. We do, however, look at a range of regulatory scenarios to try to determine the possible compliance costs.

As a result of our commitment to responsible operating practices and social responsibility, we believe we are well positioned to meet the challenges of increasing environmental regulation and social expectations that have become a significant component of sustainable resource development. We have built a corporate culture of integrity and respect for the communities and environments in which we operate and have developed policies and practices for continuing compliance with all environmental laws and regulations.

CLIMATE CHANGE

Nexen believes that climate change and the transition to a low carbon energy system are important issues. For the past decade, Nexen has been active in planning and preparing for carbon regulation and has been engaged in public discussions on this matter in jurisdictions where we operate. We have also participated in carbon markets, renewable energy initiatives and a range of carbon offset/crediting projects. We currently manage compliance for our three producing assets in the UK North Sea and in our operations in Canada (Alberta and British Columbia). The Canadian Federal government has yet to pass climate change legislation. Canada has previously announced their intent to mirror the US regulatory approach for climate-related matters but continues to state they do not have to wait if their interests were best served by unilateral action. In the US, there has been no progress on comprehensive climate/energy legislation and none is expected until after the November 2012 presidential election.

Any required reductions in the greenhouse gases (GHGs) emitted from our operations could result in increases to our capital or operating expense.

Alberta became the first jurisdiction in Canada to enact and implement binding industrial sector emission reductions (a one-time from base, 12% reduction in carbon intensity vs. a 2003—2005 baseline) on facilities annually emitting more than 100 kilo-tonnes of CO_2 equivalent. Facilities unable to achieve internal reductions have an unlimited ability to achieve compliance through payment into a technology fund at the rate of $15 per tonne of CO_2 equivalent or through the purchase of Alberta-based emission offset credits.

British Columbia enacted legislation in November 2007 titled the *Greenhouse Gas Reduction Targets Act*, which targets a 33% reduction in current provincial GHG emissions by 2020. British Columbia has been actively engaged in the Western Climate Initiative and recently enacted a GHG reporting regulation. For oil and gas operations, the facility emission reporting threshold is zero (i.e., all facilities must report regardless of size). The province also applied an economy-wide carbon tax on all hydrocarbon fuels sold in the province. The tax started at $10/tonne of CO_2 in 2008 and will increase $5 per year until it reaches $30 per tonne in 2012. It is currently unclear whether British Columbia will introduce a cap and trade system in partnership with the other Western Climate Initiative jurisdictions (California, Quebec, Ontario and Manitoba) or whether they will continue with their current or expanded carbon tax system. This situation may continue until after the next provincial election in 2013.

In 2008, the European Union (EU) introduced Phase II of the Emissions Trading Scheme (ETS), which will run until the end of 2012. Under Phase II of the ETS, member states were required to establish a national allocation plan approved by the EU. The system covers CO_2 from certain combustion and flaring activities, and member states are allowed to manage allocation across their industrial base as they see fit. Installations have the ability under the ETS to purchase allowances or other eligible instruments to ensure compliance. Phase III, scheduled to run from 2013 to 2020, may include a transition from the gratis allocation of allowances to the use of auctioning. Post-2012 auctioning of allowances for all electricity generation activities and phased reduction of free allocation of allowances for other activities, as well as phased reduction of allowance availability in general, are expected to increase our annual cost of compliance. Proposals to increase the EU reduction obligation from 20 to 30%, if implemented, could also increase our annual cost of compliance.

In 2009, the US Environmental Protection Agency (EPA) announced its findings that GHGs pose a threat to public health. In the absence of other federal programs to regulate GHGs, the EPA has initiated regulatory activity under the authority of the *Clean Air Act*. The facility threshold for this action is currently set at 25,000 tonnes per year, a level that none of our operated US facilities currently emits. The EPA has expressed interest in regulating smaller GHG sources, though the agency has yet to fully implement its regulation of the larger sources and no regulatory proposals have been finalized. The EPA moved back deadlines several times in 2011 and it is unclear if they will aggressively pursue these initiatives in 2012. The impact of EPA activity in the area of GHG regulation is expected to be minimal on our current operations in the Gulf of Mexico.

The Canadian Council of Ministers of the Environment (the CCME is comprised of the federal and provincial ministers) decided to pursue a federal air quality management system for the regulation of air pollutant emissions and ambient air quality. Work on equipment performance standards and ambient air quality objectives progressed through 2011. Draft regulations are expected in late 2012 with implementation beginning in 2013. While we could face technical challenges in meeting minimum emission standards for certain pollutants, we are unable at this time to estimate the cost of compliance and impact on our operations.

To meet our current and projected GHG emissions obligations, we continue to pursue a four-point emissions management strategy:

- reduce direct GHG emissions at our facilities;
- self-generate carbon credits from wind power;
- acquire carbon credits through qualified projects and authorized agencies; and
- participate in eligible international and domestic offset projects.

WATER

We have developed a water strategy designed to minimize water use in our exploration and production operations. This strategy is embodied by the following four principles:

- optimize water use efficiency;
- minimize our impacts on ecosystem functions and ensure public health and safety are not affected by our activities;
- engage with stakeholders to promote responsible watershed management and evaluate opportunities to provide water management benefits to stakeholders; and
- measure and communicate our water management performance.

This strategy was implemented in 2009 with an emphasis on compliance and early adoption of best practices, incorporating water assessment in our investment decision-making process and developing water management systems to enhance water tracking and reporting. Our water data management project, which started in 2011, provides us with enhanced abilities to improve water efficiency.

LAND AND BIODIVERSITY

Our land use practices are based upon principles of minimal disturbance and a legal commitment to return the land to a natural state after responsibly producing oil and gas resources. We also recognize our ability to effectively access land is directly linked to the way in which we manage the potential environmental impacts and in how we engage with local communities, stakeholders, regulators and other industries to reduce the cumulative effects of our projects throughout their life–cycle.

For many stakeholders, a company's ability to meet environmental expectations is a significant criterion upon which their decision to invest or conduct business is based. A failure to meet those expectations can limit access to exploration, development and partnership opportunities. Therefore, we believe that environmental and social responsibility performance is directly linked to economic performance.

We have outlined and more fully discussed our environmental practices and policies in our sustainability report, available on our website at www.nexeninc.com.

Community Investment

Giving back to the communities in which we operate is a deeply rooted value at Nexen. The company's "ReachOut—Giving, Matching, Helping" community involvement strategy supports the priorities of our employees and communities while providing a strategic link to our business.
The "ReachOut" program focuses on three key areas:

- Giving—Supporting communities where Nexen has operations through meaningful corporate gifts;
- Matching—Nexen matching charitable contributions made by our employees; and
- Helping—Nexen builds employees engagement and stronger communities through volunteering.

Details regarding Nexen's community investment initiatives are available in our sustainability report and on our website.

Environmental Provisions and Expenditures

Meeting the challenges of environmental regulation and our commitment to sustainable resource development affects all stages of our operations and generally increases their cost. Environmental commitments and regulation can increase the operating or capital cost of operations, delay requisite permits or approvals from issuing authorities and could result in unprofitable operating conditions. During 2011, we incurred both capital and operational expenses, including expenses related to environmental control facilities. Those costs were not material and did not impair our ability to execute our business or operating strategy. We will continue to incur these costs in the future and expect they will be manageable. At December 31, 2011, $2,076 million ($3,481 million undiscounted, adjusted for inflation) has been provided in our Consolidated Financial Statements for asset retirement obligations.

EMPLOYEES

We had 3,067 employees on December 31, 2011.

MANAGEMENT'S DISCUSSION AND ANALYSIS

MANAGEMENT'S DISCUSSION AND ANALYSIS

Executive Summary	63
Capital Investment	64
Financial Results	69
Oil & Gas	70
Oil & Gas Cash Netbacks	76
Corporate	77
Summary of Quarterly Results	80
Outlook for 2012	81
Liquidity and Capital Resources	82
Critical Accounting Estimates	87
New Accounting Pronouncements	89
Quantitative and Qualitative Disclosures About Market Risk	90
Other	92
Forward-Looking Statements	93

MANAGEMENT'S DISCUSSION AND ANALYSIS (MD&A)

The following should be read in conjunction with the Consolidated Financial Statements of Nexen Inc. as at and for the year ended December 31, 2011. The Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB). The date of this discussion is February 15, 2012. Unless otherwise noted, tabular amounts are in millions of Canadian dollars. Oil and gas volumes, reserves and related performance measures are presented on a working-interest before-royalties basis. We measure our performance in this manner consistent with other Canadian oil and gas companies. Where appropriate, we have provided information on an after-royalty basis.

Investors should read the "Forward-Looking Statements" on page 93.

Proved and probable reserves estimates included in this MD&A have been prepared in accordance with National Instrument 51-101—Standards of Disclosure for Oil and Gas Activities (NI 51-101). We have also prepared reserves estimates and disclosures in accordance with SEC requirements, which are included in Appendix B of our 2011 Annual Information Form (AIF). Our AIF is available from our public filings with the Canadian Securities Administrators at www.sedar.com or from our website www.nexeninc.com. Investors should read the "Special Note to Investors" on page 58 in our 2011 Annual Report for a qualitative description of the differences between NI 51-101 and SEC reserve estimates and disclosures.

EXECUTIVE SUMMARY

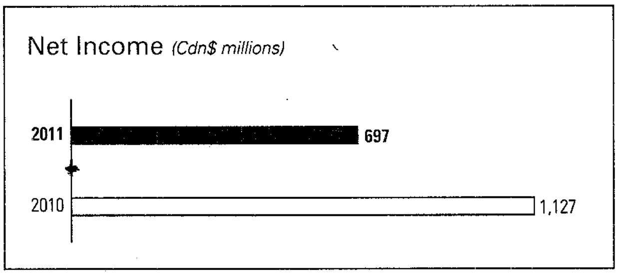
(Cdn$ millions, except otherwise indicated)	**2011**	**2010**
Production before Royalties[1,2] *(mboe/d)*	207	246
Production after Royalties[2] *(mboe/d)*	186	220
Total Revenues and Other Income[2]	6,853	7,266
Cash Flow from Operations[2,3]	2,368	2,150
Net Income[2]	697	1,127
Earnings per Common Share, Basic[2] *($/share)*	1.32	2.15
Earnings per Common Share, Diluted[2] *($/share)*	1.24	2.09
Dividend *($/share)*	0.20	0.20
Total Assets	20,068	19,647
Net Debt[4]	3,538	4,085

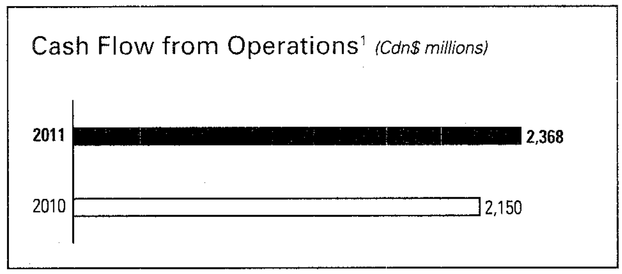
1 *Production before royalties reflects our working interest before royalties. We have presented our working interest before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies. At Long Lake, we report bitumen as production.*
2 *Includes results of discontinued operations (see Note 23 of our Consolidated Financial Statements).*
3 *Cash flow from operations is a non-GAAP measure and is reconciled to the nearest GAAP measure on page 92.*
4 *Net debt is a non-GAAP measure and is reconciled to the nearest GAAP measure on page 92.*

High oil prices contributed to strong financial results in 2011. Cash flow from operations was $2.4 billion and net income was $697 million. Cash flow from operations reached its highest level since 2008 as our weighting to crude oil prices, in particular to Brent crude oil, allowed us to realize strong cash netbacks. Earnings for 2011 were also strong, despite non-recurring expenses of $322 million related to impairment charges and $253 million related to costs associated with our shift away from large, integrated upgrading projects in our future oil sands development strategy.

Production averaged 207,000 boe/d in 2011, 16% below last year. Operational issues at Buzzard in the UK North Sea through the first nine months of the year, natural field declines in Yemen and the disposition of our heavy oil assets in 2010 were the primary reason for the reduction. Production in 2010 included about 9,000 boe/d from heavy oil properties, which were sold in the third quarter of 2010. Fourth quarter 2011 production averaged 208,000 boe/d, 22,000 boe/d higher than the third quarter. This increase was due to improved uptime at Buzzard, new production from the Blackbird field and increases in production at Long Lake and Horn River shale gas. On December 17, 2011, our production sharing agreement expired on the Masila block in Yemen and the assets were transferred to the Yemen Government.

Crude oil prices continued an upward trend in 2011 with Brent increasing 40% and WTI increasing 20% from last year. The Brent/WTI premium widened to average US$16.16/bbl for the year. The benefit of these high commodity prices was partially offset by the stronger Canadian dollar, which strengthened 4 cents in the year. Our realized crude oil and gas prices increased 30% in 2011 and averaged $91.46/boe. Cash netbacks from oil and gas operations increased from last year to average $40.20/boe as a result of the higher prices.





1 *Cash flow from operations is a non-GAAP measure and is reconciled to the nearest GAAP measure on page 92.*

Our non-core asset disposition program generated proceeds of $518 million and net pre-tax gains of $386 million in 2011. This follows a 2010 program which generated proceeds of $1.3 billion and net pre-tax gains of $787 million.

Net debt declined 13% in 2011 and 36% over the past two years, as proceeds from non-core asset dispositions were used to repay debt. During 2011, we repurchased and cancelled approximately $800 million of long-term debt. Our available liquidity has increased and is currently $4.2 billion, comprised of cash and undrawn committed credit facilities, most of which are available until 2016.

CAPITAL INVESTMENT

Our strategy and capital programs are focused on growing value responsibly for our shareholders. We aim to capture resource early and at low cost. To maximize value, we invest in:

- core assets for short-term production and free cash flow to fund capital programs and enhance financial capacity;
- development projects that convert our discoveries into new production and cash flow in the medium term; and
- appraisal, exploration and new growth projects for longer-term growth.

We focus on key investment areas including Athabasca oil sands, Canadian shale gas and conventional offshore opportunities in the North Sea, deep-water Gulf of Mexico, and offshore West Africa—areas we believe have attractive fiscal terms, significant exploration potential and where we believe we have a competitive advantage.

In 2011, we invested $2.5 billion in oil and gas activities and increased our proved reserves by 73 mmboe and our probable reserves by 175 mmboe. A summary of our 2011 capital investment program and reserve additions is provided in the table below. Additional information on our oil and gas reserves can be found in Reserves, Production and Related Information on page 38 of the Business Overview.

	Capital Investment *(Cdn$ millions)*	Production[1] *(mmboe)*	Proved Reserve Increase[1] *(mmboe)*	Probable Reserve Increase[1] *(mmboe)*
Conventional Oil and Gas	1,525	59	25	47
Oil Sands	521	14	18	10
Shale Gas	470	3	30	118
Total Oil and Gas	**2,516**	**76**	**73**	**175**

1 *Before royalties.*

Our strategy is to build a sustainable energy company focused in three growth areas: conventional oil and gas, oil sands and shale gas. Our investment in these areas in 2011 is highlighted below:

- **conventional oil and gas**—our conventional investment program was based in the North Sea, deep-water Gulf of Mexico and offshore West Africa. Development of the Usan field offshore West Africa progressed on schedule and first production is expected in the next month or two. In the North Sea, we received partner and regulatory approvals for Golden Eagle and progressed tie-backs for the Blackbird, Telford TAC and Rochelle projects. We resumed exploratory and appraisal drilling in the Gulf of Mexico at Kakuna and Appomattox.
- **oil sands**—at Long Lake, we advanced on our plans to develop approximately 60 additional wells in higher-quality reservoir areas of the Long Lake and Kinosis leases in order to fill the upgrader and to improve the reliability of the operations.
- **shale gas**—we accelerated value recognition from our northeast British Columbia shale gas assets as we secured joint venture partners to sell a 40% working interest, which is expected to close in the second quarter of 2012. We continued to execute well as production from the nine-well pad started up ahead of schedule and drilling of the 18-well pad remains on-time and on-budget. First production from the 18-well pad is expected in late 2012.

During 2011, our proved oil and gas reserves additions replaced 96% of our oil and gas production (90% after royalties). On a proved plus probable basis, reserves increased 8% over 2010, net of production.

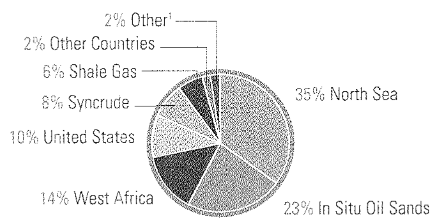
The majority of our proved additions are a result of ongoing exploration and development activities at Horn River, Buzzard and Long Lake.

Our 2011 proved reserve additions are not necessarily indicative of future annual additions which will be dependent on such factors as oil and gas prices, capital allocations, nature of our drilling programs, exploration success and expected timing of proceeding with development of reserves discovered. Management uses the reserves replacement ratio as a measure for our success in replacing reserves produced. A significant portion of our properties involve large-scale, multi-year development projects and as a result, we review this ratio over the longer term.

Our capital investment is shown below:

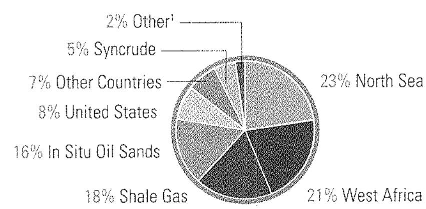
(Cdn$ millions)	**Estimated 2012**	**2011**	**2010**
Conventional Oil & Gas			
UK North Sea	975–1,100	583	699
West Africa	400–425	543	495
US Gulf of Mexico	300–325	216	261
Other	50	183	143
	1,725–1,900	**1,525**	**1,598**
Oil Sands			
Long Lake, Kinosis and Other In Situ	550–800	397	228
Syncrude	220–250	124	119
	775–1,050	**521**	**347**
Shale Gas	**150–200**	**470**	**568**
Total Oil and Gas	**2,650–3,150**	**2,516**	**2,513**
Corporate and Other	50	59	211
Total Capital	**2,700–3,200**	**2,575**	**2,724**

2012 Estimated Capital



1 *Energy Marketing, Corporate and Other.*

2011 Capital



1 *Energy Marketing, Corporate and Other.*

Conventional Oil and Gas

OFFSHORE WEST AFRICA

Development of the Usan field remains on schedule; the project is our largest source of new production in 2012 and is expected to contribute to significantly stronger corporate cash netbacks this year. Final commissioning activities are in progress and first production is expected in the next month or two. Development activities have not been affected by earlier civil unrest in Nigeria. At peak rates, Usan's facility capacity is 180,000 bbls/d (36,000 bbls/d net to Nexen); actual production rates will vary within that capacity based on well performance, pace of ramp-up and facility uptime. We have a 20% interest in exploration and development on this block along with partners ExxonMobil, Chevron and operator Total E&P Nigeria Limited.

We expect to drill an exploration well at Owowo West in 2012. This well is targeted to follow-up on our earlier success at Owowo South B.

UK NORTH SEA

Following final regulatory approval of the Golden Eagle development early in the fourth quarter, we began work on the fabrication of the facilities, utilizing many of the same teams that oversaw the successful construction of the Buzzard platforms. The work is proceeding on-time and on-budget, and we expect first production in late 2014. The facility will have a capacity of 70,000 boe/d (26,000 boe/d net to Nexen).

We also continue to progress our tieback projects in the North Sea. Blackbird came on-stream through the Ettrick facility in November, and is currently producing to expectations. The remaining two projects, Telford TAC and Rochelle, will tieback to our Scott platform. Telford TAC came on stream in February 2012; Rochelle is proceeding as planned and first production is expected around the end of 2012. Elsewhere in the North Sea, appraisal drilling continued at Polecat, followed by an exploration well at Edgware. We continue to have an active UK exploration program, including the North Uist exploration well west of the Shetland Islands, where drilling is expected to begin late in the first quarter.

US GULF OF MEXICO

We returned to drilling in the Gulf of Mexico during 2011 with the spud of our Kakuna well, which is expected to reach target depth around the end of the first quarter. We expect to drill our next operated exploration well in the Gulf, at Angel Fire, later this year.

At Appomattox, we followed-up our successful 2010 exploration well in the south fault block with another success in the northeast fault block. The well confirmed oil and we are currently completing an evaluation to determine the size of the discovery. Resource on the northeast block would be in addition to the 65 mmboe of probable reserves we booked on the south block. We have a 20% interest in Appomattox, the remaining interest is held by Shell Offshore Inc., who is the operator.

We plan to continue drilling at Appomattox with an appraisal well on the south fault block and a sidetrack appraisal well on the northwest fault block to test the third major part of the Appomattox structure. We have a 20% interest in Appomattox, the remaining interest is held by Shell Offshore Inc., who is the operator.

In late 2011, we finalized a joint venture agreement with China National Offshore Oil Corporation (CNOOC) to farm-down on our higher working interest prospects in the Gulf of Mexico on a promoted basis. This JV agreement gives CNOOC a 20% working interest in Kakuna, Angel Fire and Cypress. CNOOC may also participate in three additional exploration wells with a 10 to 25% working interest.

Oil Sands

At Long Lake, our focus is on advancing the 60 additional wells to fill the upgrader.

In the fourth quarter, Long Lake showed progress. Total production increased 7% over the prior quarter with 31,500 bbls/d of gross bitumen at an SOR of 4.8. Upgrader yield (PSC™ barrels per barrel of bitumen) was 76% and facility on-stream time was 78%. Per barrel operating costs were also lower than previous quarters, primarily due to the increased production and the higher yield. These factors contributed to positive cash flow from operations of $22 million in the quarter and $5 million for the full year.

LONG LAKE QUARTERLY OPERATING METRICS

	Bitumen Production (Gross) *(bbls/d)*	**Steam Injection (Gross)** *(bbls/d)*	**Per Unit Operating Cost**[1] *(Cdn$/bbl)*	**Cash Flow** *(Cdn$ millions)*	**Realized Price**[1] *(Cdn$/bbl)*
2011					
Q4	31,500	151,000	67	22	97
Q3	29,500	144,000	85	(4)	94
Q2	27,900	152,000	95	6	109
Q1	25,500	146,000	89	(19)	90
2010					
Q4	28,100	158,000	86	(9)	83
Q3	25,700	146,000	85	(42)	71
Q2	24,900	137,000	90	(19)	74
Q1	18,700	114,000	154	(58)	81

1 *Unit operating costs and realized prices are based on PSC™ and bitumen volumes sold and exclude activities related to third-party bitumen purchased, processed and sold. Unit operating cost includes energy cost.*

Over the past few weeks, gross production at Long Lake has increased to approximately 35,000 bbls/d. This reflects successful and ongoing well optimization initiatives and the growth in pad 11 production. Pad 11 is currently producing approximately 4,500 bbls/d and is continuing to ramp-up. The expected production range for this pad is 4,000 to 8,000 bbls/d.

We are making steady progress on our plans to fill the upgrader. Drilling has concluded on pads 12 and 13, and well completion activities are underway. We remain on track to begin steaming pad 12 in the spring; pad 13 is expected to follow sometime in the late summer or early fall. Production from both pads is expected before the end of the year. These pads specifically targeted higher-quality resources; our drilling results confirm that the resource quality is as we expected.

The regulatory approvals for pads 14, 15 and Kinosis K1A are progressing. We are awaiting approvals for one or both projects this spring, which would enable us to begin drilling next winter. These wells have geological characteristics similar to our current best-producing wells.

In aggregate, we anticipate these wells will allow us to fill the upgrader within the next several years:

	Number of Wells	Expected Rates *(bbls/d)*
Pad 11	10	4,000–8,000
Pads 12 and 13	18	11,000–17,000
Pads 14 and 15	10–12	6,000–9,000
Kinosis K1A	25–30	15,000–25,000

We are also continuing work on a non-operated SAGD project at Hangingstone, of which we own 25%. The operator has delayed sanctioning of the project until the fourth quarter of 2012 in order to provide additional time to complete the regulatory approval process. Our share of production at full rates is expected to be about 6,000 bbls/d after the project comes on-stream in 2016.

Shale Gas

NORTHEAST BRITISH COLUMBIA

We continued to execute on our Horn River shale gas program during the year. Our nine-well pad started up ahead of schedule and early production results are meeting expectations. Preliminary results indicate initial rates up to 18 mmcf/d per well. We are currently producing at our facility capacity of 50 mmcf/d.

Work continues on our 18-well pad and we remain on-time and on-budget. We anticipate that production from this pad will begin in the fourth quarter, in conjunction with an increase in our facility capacity. This is expected to bring our total gross production capacity to 175 mmcf/d.

We completed our process to secure a joint venture partner for a portion of our northeast British Columbia shale gas assets. We reached an agreement to sell a 40% working interest in our Horn River, Cordova and Liard assets at a 60% premium to our invested costs to a consortium led by INPEX Corporation and will remain the operator. This joint venture is expected to close in the second quarter of 2012.

INTERNATIONAL

We completed drilling the first shale gas exploration well in Colombia at Sueva-1. We are currently evaluating the results of this well and also drilling our second well at Junin-1.

We expanded our exploration activities into Poland during the year with a joint venture agreement. Drilling of the first well has recently been completed and analysis of data collected from the well is underway.

FINANCIAL RESULTS

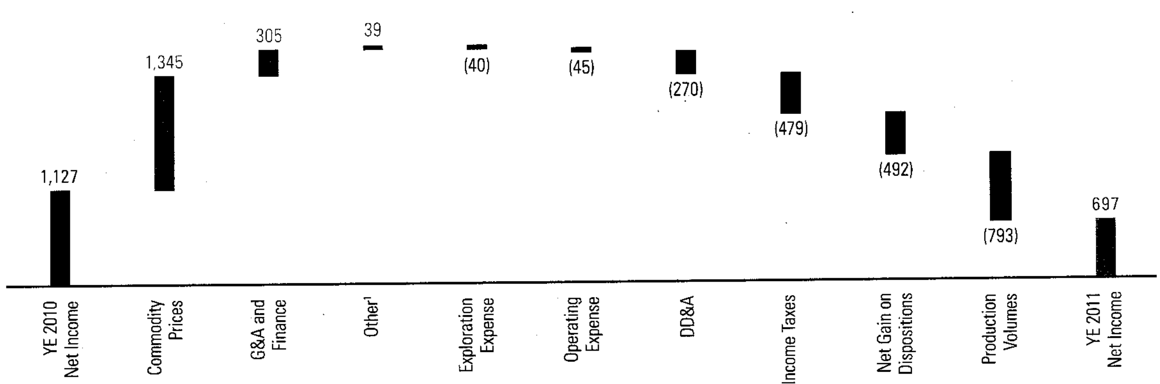
Year-to-Year Change in Net Income

(Cdn$ millions)	**2011 vs 2010**
Net Income for 2010[1]	**1,127**
Favourable (Unfavourable) Variances:[2]	
Production Volumes, After Royalties	
Crude Oil	(855)
Natural Gas	(32)
Change in Crude Oil Inventory	94
Total Volume Variance	(793)
Realized Commodity Prices	
Crude Oil	1,365
Natural Gas	(20)
Total Price Variance	1,345
Oil & Gas Operating Expense	(45)
Oil & Gas Depreciation, Depletion, Amortization and Impairment	(270)
Exploration Expense	(40)
Net Gain on Dispositions and Loss on Debt Redemption and Repurchase	(492)
Energy Marketing Contribution	59
Canexus[3]	(58)
General and Administrative Expense	174
Finance Costs	131
Provision for Income Taxes	(479)
Other	38
Net Income for 2011[1]	**697**

1 *Includes results of discontinued operations (see Note 23 of our Consolidated Financial Statements).*
2 *All amounts are presented before provision for income taxes.*
3 *We disposed of our investment in Canexus in the first quarter of 2011 (see Note 23 of our Consolidated Financial Statements).*

Significant variances in net income are explained in the sections that follow.

Year-to-Year Change in Net Income *(Cdn$ millions)*



1 *Includes Energy Marketing, Canexus and other year-to-year changes in net income.*

OIL & GAS

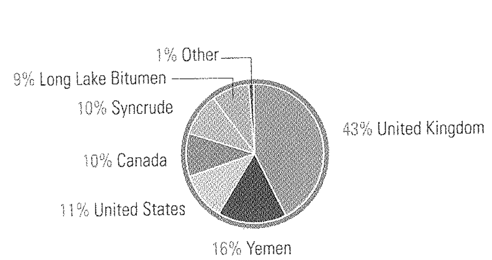
Production

	2011		2010	
	Before Royalties[1]	After Royalties	Before Royalties[1]	After Royalties
Oil and Liquids *(mbbls/d)*				
United Kingdom	85.0	84.7	104.9	104.8
Yemen	32.9	18.1	41.3	23.1
Oil Sands—Syncrude	20.9	19.2	21.2	19.6
Oil Sands—Long Lake Bitumen[2]	18.6	17.3	15.9	15.1
United States	8.2	7.4	9.9	9.0
Canada[3]	–	–	7.5	5.8
Other Countries	1.7	1.6	2.1	1.9
	167.3	148.3	202.8	179.3
Natural Gas *(mmcf/d)*				
United Kingdom	30	30	35	35
United States	86	78	99	94
Canada[3]	123	117	126	116
	239	225	260	245
Total *(mboe/d)*	**207**	**186**	**246**	**220**

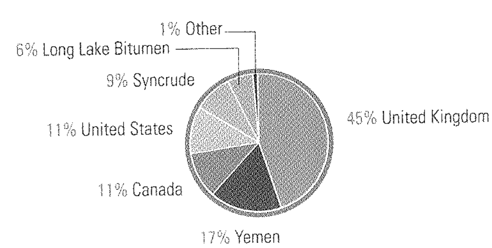
1 *We have presented production volumes before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.*
2 *We report Long Lake bitumen as production.*
3 *Includes the following production from discontinued operations in 2010 (see Note 23 to our Consolidated Financial Statements):*

	2011	*2010*
Before Royalties		
Crude Oil and NGLs (mbbls/d)	–	7.5
Natural Gas (mmcf/d)	–	6
After Royalties		
Crude Oil and NGLs (mbbls/d)	–	5.8
Natural Gas (mmcf/d)	–	5

2011 Production before Royalties



2010 Production before Royalties



2011 VS 2010—LOWER VOLUMES DECREASED NET INCOME BY $793 MILLION

Production before and after royalties decreased approximately 16% from 2010 levels. Operational issues at Buzzard in the North Sea and natural field declines in Yemen were primary reasons for the decrease. Production in 2010 included about six months of volumes from heavy oil assets that were sold in the third quarter of 2010. The following table summarizes our production changes year over year:

(mboe/d)	Before Royalties	After Royalties
2010 Production	246	220
Production Related to Disposed Properties	(9)	(7)
	237	213
Production Changes		
United Kingdom	(21)	(21)
Yemen	(9)	(5)
United States	(4)	(4)
Oil Sands—Long Lake Bitumen	3	2
Canada	1	1
2011 Production	**207**	**186**

Fourth quarter production averaged 208,000 boe/d (193,000 boe/d after royalties), 22,000 boe/d higher than the third quarter of 2011. Resolution of the operational issues at Buzzard and production from the Blackbird tieback to Ettrick contributed to higher volumes in the UK North Sea. Production also increased at Long Lake and Horn River shale gas, offsetting the expiry of the Masila contract in mid-December. Compared to the fourth quarter of 2010, production decreased 38,000 boe/d. The decrease reflects natural declines in Yemen, the US Gulf of Mexico and Ettrick in the North Sea. This was partially offset by higher production at Long Lake and new production from the Blackbird tieback.

United Kingdom

UK production decreased 19% from last year to average 90,000 boe/d, primarily as a result of various operational issues at Buzzard. Buzzard production was 62,400 boe/d in 2011, 23% lower than 2010. Unplanned maintenance on the cooling system, third-party pipeline outages and delays in commissioning the fourth platform were the primary factors for the decrease.

Unscheduled maintenance on the Buzzard cooling system began in the first quarter of 2011, with permanent upgrades to the cooling system completed in the third quarter. Restrictions on the third-party Forties and Frigg pipelines also reduced production. These restrictions required us to reduce oil production to minimize gas flaring for six weeks. These export constraints and unscheduled maintenance also delayed commissioning of the fourth platform and we experienced higher than expected downtime during commissioning. Reliability at Buzzard improved during the fourth quarter following commissioning of the fourth platform; our production efficiency rate was 86% without planned downtime. For 2012, we are targeting 85% before planned shutdowns (78% including scheduled downtime).

Production from the Ettrick field contributed 14,000 boe/d to our annual volumes, consistent with 2010. A one-week planned shutdown for Blackbird tie-in activities in August and planned maintenance shutdowns temporarily limited Ettrick production in 2011. Following the tie-in, Blackbird came on-stream in November 2011, seven weeks ahead of schedule, and is currently producing on the high side of our expectations. Production in the fourth quarter was approximately 5,000 boe/d (gross). Scott/Telford averaged 13,000 boe/d, slightly lower than 2010 primarily as a result of natural declines in the Scott field, scheduled maintenance on the platform and downtime to commence tie-in of the Telford TAC development well in the fourth quarter. First production from the Telford TAC tieback was achieved in February.

In 2012, we expect our share of production from the North Sea to average between 94,000 and 117,000 boe/d. Increases are expected to come from improved uptime at Buzzard and additional volumes from the Blackbird field and the Telford TAC development.

Yemen

Production in Yemen decreased 20% compared to 2010, due to natural field declines, limited capital investment and the end of our Block 14 Masila production sharing agreement on December 17, 2011. We continue to operate Block 51 in Yemen and current production is approximately 5,000 bbls/d here.

Syncrude

Syncrude production averaged 20,900 bbls/d for the year, consistent with 2010. Unscheduled repairs to Hydrogen Plant 9-4 temporarily reduced production in the fourth quarter of 2011. In 2012, we expect our share of production to average between 21,000 and 23,000 bbls/d.

Long Lake

Fourth quarter bitumen production at Long Lake increased 7% from the third quarter to average 31,500 bbls/d (20,500 bbls/d net to us) at an SOR of 4.8. Annual bitumen production increased 17% to average 28,600 bbls/d (18,600 bbls/d net to us). Over the past few weeks, production at Long Lake has increased to approximately 35,000 bbls/d. This reflects successful and ongoing well optimization initiatives and the continued growth of pad 11. Pad 11 is currently producing approximately 4,500 bbls/d and is continuing to ramp-up. The expected production range for this pad is 4,000 to 8,000 bbls/d.

In 2012, we expect annual bitumen production at Long Lake to average between 29,000 and 38,000 bbls/d (19,000 and 25,000 bbls/d, net to us), including the impact of the 2012 planned turnaround. The three-week SAGD turnaround and six-week upgrader outage is expected to take place in the third quarter.

United States

Production in the Gulf of Mexico averaged 22,600 boe/d in 2011, 14% below 2010, primarily as a result of natural field declines and to a lesser extent, downtime from Tropical Storm Lee. In 2012, we expect our share of production from the Gulf of Mexico to average between 15,000 and 19,000 boe/d.

Canada

After eliminating the impact of the sale of the heavy oil properties in 2010, production in Canada increased 3% in 2011. Shale gas production for the year averaged 38 mmcf/d, more than triple the previous year's production. Production from our nine-well pad came on stream in late October. Preliminary results indicate initial rates up to 18 mmcf/d per well. We are currently producing slightly above our planned facility capacity of 50 mmcf/d as optimization work is allowing the facility to operate above expectations. Production from our conventional gas and CBM properties in western Canada declined 21%.We are limiting capital investment in these mature properties as a result of the weak natural gas price environment. In 2012, we expect our share of production from Canada to average between 15,000 and 19,000 boe/d.

Other Countries

Production from Colombia decreased 400 bbls/d from last year to average 1,700 bbls/d in 2011, primarily as a result of natural field declines. We expect our share of production to average between 1,000 and 2,000 bbls/d in 2012.

Commodity Prices

	2011	**2010**
Crude Oil		
Dated Brent (Brent) *(US$/bbl)*	111.28	79.47
West Texas Intermediate (WTI) *(US$/bbl)*	95.12	79.52
Benchmark Differentials[1] *(US$/bbl)*		
Mars	12.35	(1.54)
Masila	15.27	0.09
Realized Prices from Producing Assets *(Cdn$/bbl)*		
United Kingdom	106.76	79.02
Yemen	108.11	81.86
Oil Sands—Syncrude	101.73	81.23
Oil Sands—Long Lake	98.33	77.07
United States	99.65	76.73
Canada	–	61.39
Other Countries	102.71	76.83
Corporate Average *(Cdn$/bbl)*	105.21	78.94
Natural Gas		
New York Mercantile Exchange (NYMEX) *(US$/mmbtu)*	4.03	4.39
AECO *(Cdn$/mcf)*	3.48	3.92
Realized Prices from Producing Assets *(Cdn$/mcf)*		
United Kingdom	7.42	5.28
United States	4.21	4.97
Canada	3.44	3.94
Corporate Average *(Cdn$/mcf)*	4.31	4.54
Nexen's Average Realized Oil and Gas Price *(Cdn$/boe)*	**91.46**	**70.11**
Average Foreign Exchange Rate—Canadian to US Dollar	1.0117	0.9709

1 These differentials are a premium/(discount) to WTI.

2011 VS 2010—HIGHER CRUDE OIL PRICES INCREASED NET INCOME BY $1,345 MILLION

Crude oil prices continued to strengthen in 2011 with Brent and WTI increasing 40% and 20%, respectively, over 2010 levels. Approximately 70% of our crude oil production is priced off of Brent. Brent traded at a premium to WTI reflecting significant inventory levels at Cushing, Oklahoma, which reduced WTI prices relative to Brent. The stronger Canadian dollar reduced some of the impact of higher prices, as our realized crude oil price was $105.21/bbl, 33% higher than 2010. In North America, NYMEX and AECO natural gas prices decreased 8% and 11% from the prior year, respectively. Our realized natural gas price decreased only 5% to average $4.31/mcf, as a portion of our natural gas production is located in the UK North Sea where prices are higher.

The Canadian/US exchange rate averaged close to par during 2011, an increase of 4 cents relative to 2010. This change reduced sales by approximately $250 million. Offsetting this impact, our US-denominated operating expenses and capital expenditures are lower when translated to Canadian dollars.

Crude Oil Reference Prices

Brent crude oil prices traded between US$92/bbl and US$127/bbl during the year, while WTI traded between US$75/bbl and US$115/bbl. Crude prices increased in response to global economic recovery in 2011, primarily driven by growth in emerging markets. Additionally, unrest and potential supply disruptions in the Middle East and North Africa supported stronger crude prices.

Crude Oil Differentials

The Brent premium to WTI reached unprecedented levels in 2011. Historically, Brent has traded at a slight discount to WTI because surplus North Sea crude oil was exported to the US market. Significant crude oil inventory levels at Cushing, Oklahoma kept WTI discounted to Brent in 2011. The differential widened from US$4/bbl early in the year to US$30/bbl in the third quarter. The differential contracted to US$9/bbl by the end of the year, following announcements of additional pipeline capacity from Cushing to the Gulf Coast. Our North Sea, Yemen and Gulf of Mexico oil production is priced based on Brent crude oil prices.

Synthetic crude prices remained strong relative to WTI driven by short-term production disruptions of synthetic crude. We receive synthetic crude oil prices for our Long Lake PSC™ and Syncrude sales.

Mars, the primary benchmark for most of our Gulf of Mexico oil production, is a medium sour crude that is priced to compete with comparable international import alternatives by Gulf Coast refineries. Since it is produced in the Gulf of Mexico, Mars competes with waterborne crudes that are priced relative to higher global benchmarks.

The Masila price differential to Brent averaged a discount of US$0.89/bbl as it continued to follow the upward movement in international crude prices and strong demand from Asian countries.

Natural Gas Reference Prices

NYMEX natural gas prices traded between US$3/mmbtu and US$5/mmbtu. Continued low North American natural gas prices were driven by increasing gas supply from shale gas production. In the global natural gas market, LNG imports are primarily linked to crude oil prices, which should keep gas prices higher in Europe and Asia than in North America in the near term.

Operating Expenses[1,2]

	2011		2010	
(Cdn$/boe)	**Before Royalties**	**After Royalties**	**Before Royalties**	**After Royalties**
Conventional Oil and Gas				
United Kingdom	10.60	10.64	8.28	8.28
North America	11.15	12.20	11.16	12.38
Other Countries	12.73	22.54	10.09	17.83
Average Conventional	11.18	12.63	9.39	10.64
Oil Sands				
Long Lake[3]	83.44	90.22	100.09	105.25
Syncrude	37.78	40.94	34.34	37.18
Average Oil and Gas	19.00	21.30	15.48	17.40

1 Includes results of discontinued operations (see Note 23 of our Consolidated Financial Statements).
2 Operating expenses per boe are our total oil and gas operating costs divided by our working interest production.
3 Excludes activities related to third-party bitumen purchased, processed and sold.

2011 VS 2010—HIGHER OIL AND GAS OPERATING EXPENSES REDUCED NET INCOME BY $45 MILLION
Oil and gas operating costs increased 3% primarily due to operating cost pressures. On a per unit basis, operating costs increased 23% as a result of reduced production volumes. A significant portion of our operating costs are fixed and do not vary with production rates.

Unit operating costs at Long Lake are 17% lower than the prior year primarily as a result of higher production levels. Operating costs at Long Lake are primarily fixed in nature and increased bitumen production should continue to lower operating costs per boe.

In the UK North Sea, Buzzard's operating costs per boe increased as a result of additional maintenance activities and lower production. Elsewhere in the UK, maintenance costs at Scott and Ettrick resulted in higher operating costs.

In North America, operating costs per boe were consistent with 2010, reflecting higher costs in the US Gulf of Mexico offset by a reduction in Canada as a result of property dispositions in the third quarter of 2010. In Yemen, production declines, combined with higher costs, increased our corporate average by $0.47/boe.

At Syncrude, the impact of higher maintenance costs increased our corporate average by $0.36/boe.

The stronger Canadian dollar reduced our corporate average by $0.10/boe as operating costs for our International and US operations are denominated in US dollars.

Depreciation, Depletion, Amortization and Impairment (DD&A)[1]

2011 VS 2010—HIGHER OIL AND GAS DD&A DECREASED NET INCOME BY $270 MILLION
The following table shows the composition of depreciation, depletion, amortization and impairment expense for the last two years from our oil and gas activities:

(Cdn$ millions)	**2011**	**2010**
DD&A[1]	1,284	1,450
Impairment	322	139
Derecognition of Oil Sands Costs	253	–
Total	**1,859**	**1,589**

1 Includes results of discontinued operations (see Note 23 of our Consolidated Financial Statements).

Our average per unit DD&A expense increased marginally from last year. Changes in our production mix as a result of the sale of heavy oil properties in Canada, production disruptions at Buzzard and improved production rates at Long Lake were the primary reasons for the change.

DD&A PER BOE[1,2]

	2011		**2010**	
(Cdn$/boe)	**Before Royalties**	**After Royalties**	**Before Royalties**	**After Royalties**
Conventional Oil and Gas[3]				
United Kingdom	18.92	18.98	19.24	19.25
North America	23.72	25.96	20.79	23.04
Other Countries	5.99	10.60	7.39	13.05
Average Conventional	17.27	19.51	17.12	19.39
Oil Sands[3]				
Long Lake	18.36	19.62	16.66	17.34
Syncrude	7.85	8.50	6.86	7.42
Average Oil and Gas	16.39	18.34	16.20	18.19

1 Includes results of discontinued operations (see Note 23 of our Consolidated Financial Statements).
2 DD&A per boe is our DD&A for oil and gas operations divided by our working interest production.
3 DD&A per boe excludes the impairment charges and derecognition of oil sands costs described in Note 5 of our Consolidated Financial Statements.

Our Canadian assets increased our corporate average DD&A rate by $0.66/boe. This increase was driven by higher depletion rates for natural gas properties, where low natural gas prices at the end of 2010 reduced reserves and future abandonment costs increased the carrying value of the assets.

DD&A per unit rates at Syncrude increased due to major turnaround costs, increasing our corporate average by $0.10/boe. At Long Lake, the depletion rate increased our corporate average by $0.14/boe primarily as a result of ongoing capital investment.

The stronger Canadian dollar reduced our corporate average by $0.56/boe as depletion of our international and US assets is denominated in US dollars.

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

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

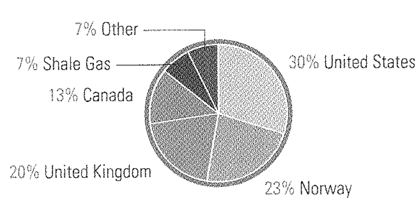
Nexen's original strategy for future oil sands development was to design and build duplicates of the existing Long Lake SAGD facilities and upgrader. We now expect to pursue smaller phase SAGD-only projects and will consider adding upgrading capacity once we are bitumen-long and economic conditions are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

Exploration Expense

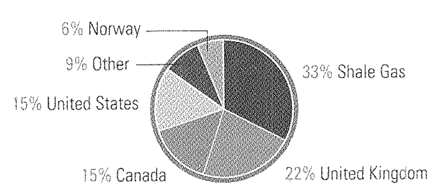
(Cdn$ millions)	2011	2010
Seismic	74	100
Unsuccessful Drilling	65	64
Other [1]	229	164
Total Exploration Expense	**368**	**328**

1 *Consists of unutilized drilling costs, exploration support costs, lease rental expenses and pre-license expenditures.*

2011 Exploration Expense by Division
($368 million)



2011 Exploration Investment by Division
($1,056 million)



2011 VS 2010—HIGHER EXPLORATION EXPENSE REDUCED NET INCOME BY $40 MILLION

Exploration expense increased 12% from last year. Our exploration program is primarily focused on opportunities in the deep-water US Gulf of Mexico, UK North Sea, offshore West Africa and Canada. In 2011, we drilled 11 wells, of which three were exploration and eight were appraisal.

Seismic expenditures decreased 26% compared to 2010. Lower spending in the US Gulf of Mexico, UK North Sea and Norway contributed to the reduction. This was offset by additional seismic acquisitions for our shale gas plays in northeast British Columbia and Poland. Seismic data costs fluctuate depending on where we are in our evaluation process.

Unsuccessful drilling costs were marginally higher than last year and represented 18% of our exploration drilling capital. We expensed $30 million of exploration costs related to unsuccessful activities in the UK North Sea. We expensed $35 million of costs related to the Ronaldo exploration well in the Norwegian North Sea early in the year. We have no further exploration planned in the Norwegian North Sea.

Other exploration costs were $65 million higher than 2010, primarily due to unutilized drilling rig and service costs early in the year as a result of the drilling moratorium in the US Gulf of Mexico.

OIL & GAS CASH NETBACKS

Cash netbacks are the cash margins we receive for every equivalent barrel sold before general and administrative expenses. Our cash netbacks were 44% of realized sales prices in 2011. Cash netbacks at Long Lake improved since 2010 to average $9.84/bbl this year. Increasing bitumen production is the primary contributor, as most of the operating costs are fixed in nature. Increases in Long Lake bitumen production volumes and higher upgrading yields should continue to reduce our per unit operating cost and improve cash margins going forward.

The following table includes the sales prices, per-unit costs and netbacks for our producing assets, calculated using our working interest production before and after royalties.

Before Royalties[1]

	2011					
	Conventional			Oil Sands		
(Cdn$/boe)	**United Kingdom**	**North America**	**Other Countries[2]**	**In Situ**	**Syncrude**	**Total Oil and Gas**
Sales	103.32	39.41	107.85	98.33	101.73	91.46
Royalties and Other	(0.36)	(3.72)	(46.92)	(5.05)	(8.10)	(10.34)
Operating Expenses	(10.60)	(11.15)	(12.73)	(83.44)	(37.78)	(19.00)
In-country Taxes	(42.41)	–	(14.17)	–	–	(21.92)
Cash Netback	**49.95**	**24.54**	**34.03**	**9.84**	**55.85**	**40.20**

	2010					
	Conventional			Oil Sands		
(Cdn$/boe)	**United Kingdom**	**North America**	**Other Countries[2]**	**In Situ**	**Syncrude**	**Total Oil and Gas**
Sales	76.51	40.85	81.63	77.07	81.23	70.11
Royalties and Other	–	(4.41)	(35.18)	(3.65)	(6.27)	(8.16)
Operating Expenses	(8.28)	(11.16)	(10.09)	(100.09)	(34.34)	(15.48)
In-country Taxes	(24.36)	–	(10.29)	–	–	(13.21)
Cash Netback	**43.87**	**25.28**	**26.07**	**(26.67)**	**40.62**	**33.26**

1 *Before-royalty cash netbacks are calculated by dividing sales, royalties and other, operating expenses and in-country taxes by production before royalties. After-royalty cash netbacks are calculated by dividing sales, operating expenses and in-country taxes by production after royalties.*

2 *Includes results of conventional crude oil and natural gas operations in Yemen and Colombia.*

After Royalties[1]

	2011					
	Conventional			Oil Sands		
(Cdn$/boe)	United Kingdom	North America	Other Countries[2]	In Situ	Syncrude	Total Oil and Gas
Sales	103.32	39.41	107.85	98.33	101.73	91.46
Operating Expenses	(10.64)	(12.20)	(22.54)	(90.22)	(40.94)	(21.30)
In-country Taxes	(42.56)	–	(25.07)	–	–	(24.58)
Cash Netback	**50.12**	**27.21**	**60.24**	**8.11**	**60.79**	**45.58**

	2010					
	Conventional			Oil Sands		
(Cdn$/boe)	United Kingdom	North America	Other Countries[2]	In Situ	Syncrude	Total Oil and Gas
Sales	76.51	40.85	81.63	77.07	81.23	70.11
Operating Expenses	(8.28)	(12.38)	(17.83)	(105.25)	(37.18)	(17.40)
In-country Taxes	(24.38)	–	(18.17)	–	–	(14.85)
Cash Netback	**43.85**	**28.47**	**45.63**	**(28.18)**	**44.05**	**37.86**

1 *Before-royalty cash netbacks are calculated by dividing sales, royalties and other, operating expenses and in-country taxes by production before royalties. After-royalty cash netbacks are calculated by dividing sales, operating expenses and in-country taxes by production after royalties.*
2 *Includes results of conventional crude oil and natural gas operations in Yemen and Colombia.*

CORPORATE

General and Administrative (G&A) Expense[1]

(Cdn$ millions)	2011	2010
General and Administrative Expense before Stock-Based Compensation	377	487
Stock-Based Compensation[2]	(75)	(11)
Total	**302**	**476**

1 *Includes results of discontinued operations (see Note 23 of our Consolidated Financial Statements).*
2 *Includes cash and non-cash expenses related to our tandem option plan, stock appreciation rights plan, restricted share unit plan and performance share unit plan.*

2011 VS 2010—LOWER G&A COSTS INCREASED NET INCOME BY $174 MILLION

G&A costs decreased 37% from 2010, primarily due to lower employee costs and a recovery of stock-based compensation during the year. G&A expenses before stock-based compensation decreased $110 million primarily due to non-recurring costs in 2010 related to non-core asset dispositions.

Changes in our share price create volatility in our net income as we account for stock-based compensation using the fair-value method. During the year, we recovered non-cash stock-based compensation costs of $85 million as our stock price ended the year at $16.21/share, compared to the previous year when it closed at $22.80/share. This recovery was partially offset by cash payments for stock-based compensation programs of $10 million, 62% lower than last year.

Finance Costs[1]

(Cdn$ millions)	2011	2010
Interest	306	381
Accretion Expense Related to ARO	44	52
Other Interest Expense	27	38
Less: Capitalized Borrowing Costs	(124)	(87)
Total Finance Costs[1]	**253**	**384**
Effective Interest Rate	6.7%	5.8%

1 *Includes results of discontinued operations (see Note 23 of our Consolidated Financial Statements).*

2011 VS 2010—LOWER FINANCE COSTS INCREASED NET INCOME BY $131 MILLION

Interest costs decreased $75 million from 2010. This 20% decrease was the result of lower debt levels as we used proceeds from our non-core asset dispositions to repay drawn term credit facilities, repurchase and cancel US$812 million of fixed-rate debt, and deconsolidate the debt associated with Canexus.

Capitalized borrowing costs were $37 million higher than last year. Borrowing costs are capitalized at our Usan project offshore West Africa, Golden Eagle in the UK North Sea and Kinosis in the oil sands. We capitalized borrowing costs for the fourth platform at Buzzard in the UK North Sea until it was completed mid-year.

Income Tax Expense[1]

(Cdn$ millions)	**2011**	**2010**
Current	1,584	1,125
Deferred	(205)	(225)
Total Provision for Income Taxes	**1,379**	**900**

1 Includes results of discontinued operations (see Note 23 of our Consolidated Financial Statements).

2011 VS 2010— HIGHER TAXES DECREASED NET INCOME BY $479 MILLION

In late March, the UK government increased the supplementary tax rate on North Sea oil and gas activities, which increased the UK statutory oil and gas income tax rate from 50% to 62%. This change increased our current income tax expense by $228 million in 2011 and increased our deferred income tax liabilities, resulting in a one-time, non-cash charge of $270 million to net income.

The UK government also announced their intention to introduce legislation in 2012 to restrict relief for decommissioning expenses to the previous 50% income tax rate. If this further change is enacted, an additional non-cash charge to net income of approximately $50 to $60 million will be required.

Stronger commodity prices compared to the prior year also contributed to an increase to our income tax expense for the year. Our income tax provision includes current taxes in the UK, Yemen, Norway, Colombia and the US.

Energy Marketing

2011 VS 2010—HIGHER MARKETING CONTRIBUTION INCREASED NET INCOME BY $59 MILLION

Our energy marketing business generated solid results in 2011. The higher contribution in 2011 relative to 2010 was primarily due to a reduction in the scope of our energy marketing business last year, which triggered one-time losses for disposed contracts in the third quarter of 2010. In addition, high power prices in Alberta contributed to improved results for our power generation facilities. We generated $11 million of proceeds from the disposition of the North America commercial and industrial power business in 2011.

COMPOSITION OF MARKETING ACTIVITIES

(Cdn$ millions)	**2011**	**2010**
Trading Activities (Physical and Financial)	64	17
Other Activities	25	13
Total	**89**	**30**

TRADING ACTIVITIES

In our energy marketing group, we enter into contracts to purchase and sell energy commodities, primarily crude oil. We also use financial and derivative contracts, including futures, forwards, swaps and options for hedging and trading purposes. In 2010, we substantially completed the re-alignment of our energy marketing business to focus primarily on marketing proprietary crude oil and natural gas, which reduced our use of financial and derivative contracts. We account for all derivative contracts and commodity trading inventory using fair value accounting and record the net gain or loss from their revaluation in marketing and other income.

OTHER ACTIVITIES

We enter into fee-for-service contracts related to transportation and storage of third-party oil and gas. In addition, we earn income from our power generation facilities at Balzac and Soderglen.

FAIR VALUE OF DERIVATIVE CONTRACTS

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

We classify the fair value of our derivatives according to the following hierarchy based on the amount of observable inputs used to value the instruments.

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

At December 31, 2011, the fair value of our derivative contracts totalled $17 million. Below is a breakdown of the derivative fair value by valuation method and contract maturity:

	Maturity				
(Cdn$ millions)	**< 1 year**	**1–3 years**	**4–5 years**	**> 5 years**	**Total**
Level 1—Actively Quoted Markets	(17)	–	–	–	(17)
Level 2—Based on Other Observable Pricing Inputs	36	1	–	–	37
Level 3—Based on Unobservable Pricing Inputs	(3)	–	–	–	(3)
Fair Value at December 31, 2011	**16**	**1**	**–**	**–**	**17**

The fair values of our derivative contracts will be realized over time as the related contracts settle. Until then, the value of certain contracts will vary with forward commodity prices and price differentials.

Other[1]

(Cdn$ millions)	**2011**	**2010**
Net Gains on Sale of Non-Core Assets	386	787
Loss on Debt Redemption and Repurchase	(91)	–
Increase (Decrease) in Fair Value of Crude Oil Put Options	(23)	(41)

1 *Includes results of discontinued operations (see Note 23 of our Consolidated Financial Statements).*

In 2011, we realized net gains of $386 million on the disposition of non-core assets consisting of the following:

- 62.7% investment in Canexus for net proceeds of $458 million, realizing a gain of $348 million; and
- Duart field in the UK North Sea for proceeds of $38 million, realizing a gain of $38 million.

In 2010, we realized net gains of $787 million on the disposition of non-core assets consisting of the following:

- heavy oil properties in Canada for proceeds of $939 million, realizing a gain of $828 million;
- North American natural gas energy marketing contracts for proceeds of $11 million, recognizing a non-cash loss of $259 million, which was primarily related to the transfer of long–term physical transportation commitments;
- crude oil lease gathering, pipelines and storage assets in North Dakota and Montana for proceeds of $201 million, realizing a gain of $121 million;
- lands in the Athabasca region of northern Alberta for proceeds of $81 million, realizing a gain of $80 million; and
- an undeveloped license in the UK North Sea for proceeds and a gain of $17 million.

During 2011, we paid $525 million to redeem the US$500 million notes due in 2013. We incurred a $52 million loss on the transaction being the difference between carrying cost and the redemption price. We also paid $346 million to repurchase and cancel US$312 million of notes due in 2015 and 2017. We incurred a $39 million loss on the repurchase. Approximately 90% of the loss represents the difference between market value and the carrying value of the bonds.

We purchase crude oil put options to provide a base level of price protection without limiting our upside to higher prices. These options settle monthly or annually and unexpired options are recorded at fair value throughout their term. As a result, changes in forward crude oil prices create gains or losses on the options at each period end. In 2011, we recorded a fair value loss of $23 million on these put options (2010—$41 million loss).

SUMMARY OF QUARTERLY RESULTS

	2010				2011			
(Cdn$ millions, except per share amounts)	**Mar**	**Jun**	**Sep**	**Dec**	**Mar**	**Jun**	**Sep**	**Dec**
Net Sales from Continuing Operations	1,347	1,305	1,321	1,523	1,598	1,507	1,399	1,665
Net Income (Loss) from Continuing Operations before Income Taxes is Comprised of:								
Oil and Gas	490	610	408	436	677	660	501	297
Corporate and Other	(202)	(136)	(386)	(90)	(228)	(76)	7	(115)
	288	**474**	**22**	**346**	**449**	**584**	**508**	**182**
Net Income (Loss) from Continuing Operations	**111**	**238**	**(54)**	**159**	**(100)**	**252**	**200**	**43**
Net Income	**141**	**245**	**581**	**160**	**202**	**252**	**200**	**43**
Earnings (Loss) per Common Share from Continuing Operations *($/share)*								
Basic	0.21	0.45	(0.10)	0.30	(0.19)	0.48	0.38	0.08
Diluted	0.20	0.42	(0.10)	0.30	(0.19)	0.45	0.32	0.08
Earnings per Common Share *($/share)*								
Basic	0.27	0.47	1.11	0.30	0.38	0.48	0.38	0.08
Diluted	0.26	0.43	1.07	0.30	0.38	0.45	0.32	0.08
Dividends Declared *($/share)*	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
Common Share Prices *($/share)*								
Toronto Stock Exchange—High	25.91	26.91	22.33	23.00	27.11	25.47	23.67	18.00
Toronto Stock Exchange—Low	22.38	20.92	18.33	20.57	21.57	19.22	15.67	14.20
New York Stock Exchange—High *(US$)*	24.98	26.92	21.54	23.01	27.94	26.82	24.99	17.72
New York Stock Exchange—Low *(US$)*	21.06	19.66	17.20	20.12	21.71	19.43	15.13	13.63

Quarterly variances in net sales from continuing operations are largely driven by fluctuations in commodity prices and changes in production volumes. Brent and WTI prices increased throughout 2011. Production volumes were lower in 2011 due to the maintenance activities in the first and third quarters, gas export restrictions in the third quarter, platform commissioning in the third and fourth quarters and natural declines over the course of the year.

In the first quarter 2011, we completed the sale of our 62.7% interest in Canexus and recognized a gain of $348 million. The operating results of Canexus for the years ended December 31, 2011 and 2010 have been included in discontinued operations (see Note 23 of our Consolidated Financial Statements). The first quarter of 2011 includes a non-cash deferred tax expense of $270 million for changes to UK tax rates. Net income was reduced in the fourth quarter of 2011 by Canadian and US natural gas property impairments and by expensing preliminary engineering and design costs for future oil sands phases.

In the third quarter of 2010, net income includes gains of $828 million from the sale of heavy oil properties and a non-cash loss of $259 million from the sale of North American natural gas energy marketing contracts. Results from our Canadian heavy oil operations are included in discontinued operations for 2010.

OUTLOOK FOR 2012

Capital Investment

In 2012, we plan to invest between $2.7 and $3.2 billion to advance our growth plans as follows:

- $1.7 to $1.9 billion on the development of the Golden Eagle area and advancing tie-backs in the North Sea, the final stages of commissioning of the Usan development in offshore West Africa and on exploration and appraisal opportunities in the UK North Sea, US Gulf of Mexico and offshore West Africa. About $375 to $400 million of this will be spent on fabricating the platforms and other facilities at our Golden Eagle development. Golden Eagle is expected to produce first oil in late 2014 and, at peak production, is expected to produce 70,000 boe/d (26,000 boe/d net to Nexen).
- $775 to $1,050 million on the oil sands as we focus on advancing drilling programs at Long Lake and Kinosis to fill the upgrader and to continue to evaluate our leases, and sustaining production and cash flow at Syncrude.
- $150 to $200 million on our shale gas strategies in northeastern British Columbia, Poland and Colombia.

Approximately 20% of our capital investment program is expected to be spent on a 27-well exploration and appraisal program, with wells in the US Gulf of Mexico, the UK North Sea, West Africa, Poland, Colombia and Canada.

Production

In 2012, we expect our annual production will range between 185,000 and 220,000 boe/d (180,000 to 215,000 boe/d after royalties). The range is driven by the timing of start-up and pace of ramp-up at Usan, variability at Buzzard as we increase the rate through the fourth platform and the pace of production growth at Long Lake. Overall, we expect production before royalties to be flat relative to 2011 production as the partial year of production at Usan, growth at Long Lake and expected higher operating rates at Buzzard offset the contract expiry at Masila and extended downtime due to regulatory-driven inspections at Buzzard and Long Lake.

(mboe/d)	**2012 Estimated Production** Before Royalties	**2011 Production** Before Royalties
United Kingdom	94-117	90
Canada—Bitumen	19-25	19
Canada—Syncrude	21-23	21
West Africa	14-28	–
United States	15-19	22
Canada	15-19	20
Yemen	–	33
Other Countries	2	2
Total	**185-220**	**207**

In Yemen, we continue to produce approximately 5,000 boe/d from Block 51. This production is not included in our 2012 guidance. We are currently evaluating alternatives in respect to Block 51 and future activities in the country.

Cash Flow and Sensitivities

We expect cash flow from operations will range between $2.8 to $3.3 billion in 2012. This reflects a higher after-tax operating cash netback on a price-neutral basis relative to 2011; we expect our netback to increase 15% to above $46/boe from $40/boe largely due to the netback at Usan being greater than our corporate average netback. Our cash flow expectations assume the following:

	Average
Brent *(US$/bbl)*	$110
WTI *(US$/bbl)*	$95
NYMEX Natural Gas *(US$/mmbtu)*	$4.5
US to Canadian Dollar Exchange Rate	$0.95

Changes in commodity prices and exchange rates impact our annual cash flow from operating activities, after cash taxes, as follows:

(Cdn$ millions)	
Brent—US$1/bbl change above US$75[1]	22
Brent—US$1/bbl change below US$65[1]	16
WTI—US$1/bbl change	15
NYMEX Natural Gas—US$0.50/mcf change	16
Exchange Rate—$0.01 US/Cdn change	30

1 *Our put option program for 2012 mitigates the impact of a Brent price decline below US$75/bbl annually or US$65/bbl on a monthly basis.*

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure

(Cdn$ millions)	**December 31 2011**	**December 31 2010**
Net Debt[1]		
Public Senior Notes	3,929	4,647
Subordinated Debt	454	443
Total Debt	**4,383**	**5,090**
Less: Cash and Cash Equivalents	(845)	(1,005)
Total Net Debt[2]	**3,538**	**4,085**
Nexen Inc. Shareholders' Equity	**8,373**	**7,814**

1 *Includes all of our debt and is calculated as long-term debt and short-term borrowings less cash and cash equivalents. Net debt is a non-GAAP measure and is reconciled to the nearest GAAP measure on page 92.*

2 *December 31, 2010 excludes net debt related to our chemical operations that was included in assets and liabilities held for sale (see Note 23 of our Consolidated Financial Statements). Our remaining interest was sold in February 2011 for net proceeds of $458 million.*

Net Debt

Our net debt levels are directly related to our operating cash flows, capital expenditures and acquisition and divestiture activity. We ended the year with net debt of $3,538 million, $547 million lower than December 31, 2010. Over the last two years, we have reduced net debt by over $2 billion primarily as a result of proceeds from the sale of non-core assets. The year-over-year change in our net debt results from:

(Cdn$ millions)	2011	2010
Capital Investment	(2,575)	(2,724)
Net Proceeds from Non-core Asset Dispositions	518	1,262
Cash Flow from Operations	2,368	2,150
	311	688
Dividends on Common Shares	(105)	(104)
Issue of Common Shares	46	55
Debt Repayment Costs	(91)	–
Change in Non-Cash Working Capital	576	279
Reclassification of Canexus Net Debt Related to Sale	–	391
Other	(173)	(35)
Foreign Exchange Translation of US-dollar Debt and Cash	(17)	203
Decrease in Net Debt	**547**	**1,477**

During 2011, our net debt decreased primarily as a result of proceeds from the disposition of Canexus and working capital reductions, which were principally reductions in energy marketing inventories. Although not effecting net debt, we also repurchased and cancelled US$812 million of long-term debt using cash on hand early in the year.

The reduction in net debt reduced our leverage in 2011 as reflected in the following ratios:

(times)	2011	2010
Net Debt to Cash Flow from Operations[1]	1.5	1.9
Interest Coverage[2]	12.7	9.0

1 For purposes of this calculation, cash flow from operating activities before changes in non-cash working capital and other.
2 Earnings before interest, taxes, DD&A, exploration and other non-cash expenses, divided by interest expense (before capitalized interest).

For the year ended December 31, 2011, our net debt to cash flow from operations ratio was 1.5 times compared to 1.9 times at December 31, 2010. While we typically expect the target ratio to fluctuate between 1.0 and 2.0 times under normalized commodity prices, this can be higher or lower depending on commodity price levels and our capital investment program. Whenever we exceed our target ratio, we assess whether we need to develop a strategy to reduce our leverage and lower this ratio back to target levels over time.

Change in Working Capital

(Cdn$ millions)	December 31 2011	December 31 2010	Increase (Decrease)
Cash and Cash Equivalents	845	1,005	(160)
Restricted Cash	45	40	5
Accounts Receivable	2,247	1,789	458
Net Current Derivative Contracts	16	(10)	26
Inventories and Supplies	320	550	(230)
Accounts Payable and Accrued Liabilities	(2,867)	(2,223)	(644)
Current Income Taxes Payable	(458)	(345)	(113)
Other	115	133	(18)
Total	**263**	**939**	**(676)**

Our working capital balances decreased significantly from last year. Cash and cash equivalents decreased $160 million as we used proceeds from the disposition program and cash on hand to repurchase and cancel approximately $800 million of long-term debt. Accounts receivable increased with higher oil prices and volumes in the fourth quarter, while inventories decreased due to a reduction in crude oil inventory late in the year. Accrued liabilities increased due to higher capital spending late in the year.

At December 31, 2011, our restricted cash consisted of margin deposits of $45 million (2010—$40 million) related to exchange-traded derivative financial contracts used by our energy marketing group to economically hedge physical commodities, storage, transportation and customer sales contracts. We are required to maintain margin for net out-of-the-money derivative financial contracts.

Liquidity

We generally rely on operating cash flows to fund capital requirements over time and provide liquidity. Given the long cycle-time of some of our development projects and volatile commodity prices, it is not unusual for capital expenditures to exceed our cash flow in any given year. We also require liquidity to support our energy marketing business. We believe that maintaining strong liquidity is critical during periods of uncertain economic markets. We currently have liquidity of approximately $4.2 billion, comprised of cash and undrawn committed credit facilities.

We maintain significant committed credit facilities. At December 31, 2011, we had committed term credit facilities of $3.8 billion, of which $367 million was utilized to support letters of credit. Of this, $700 million is available until 2014 and $3.1 billion is available until 2016. We also had $393 million of uncommitted credit facilities.

From time to time, we access capital markets to meet our financing needs. We also use financial instruments to minimize exposure to fluctuating commodity prices and foreign exchange. For example, we routinely purchase WTI and Brent crude oil put options to establish a minimum value for our production. We manage our capital structure to maintain flexibility so we can fund our capital programs given the cyclical nature of the oil and gas business.

In addition to managing capital investment levels, we monitor our asset portfolio on an ongoing basis to determine whether to sell our interest or acquire additional working interests. In the last two years, we sold non-core assets such as our interest in Canexus, heavy oil properties in Canada and various energy marketing businesses, as well as entered into joint venture agreements in northeast British Columbia and the Gulf of Mexico.

The following table shows how we financed our business activities over the last five years. When our operating cash flows exceed our investment requirements, we generally pay down debt or return cash to shareholders. We borrow money or may issue equity to fund investment requirements that exceed our operating cash flow.

(Cdn$ millions)	**2011**	**2010**	**2009**[1]	**2008**[1]	**2007**[1]
Cash Flow from Operating Activities	2,497	2,392	1,886	4,354	2,830
Cash Flow from Investing Activities	(1,757)	(1,465)	(3,743)	(3,189)	(3,281)
Surplus (Deficiency)	740	927	(1,857)	1,165	(451)
Cash Flow from Financing Activities	(932)	(1,506)	1,821	322	677
Net Cash Generated (Used)	**(192)**	**(579)**	**(36)**	**1,487**	**226**

1 Prior to 2011, our financial statements were prepared in accordance with previous Canadian GAAP. In the first quarter of 2011, we adopted IFRS with an effective date as at January 1, 2010 and restated the 2010 financial results to be in accordance with IFRS. Further details regarding our transition to IFRS are included in Note 26 of the Consolidated Financial Statements. As such, amounts prior to 2010 are presented in accordance with previous Canadian GAAP and have not been restated.

Over the last two years, our non-core asset disposition program raised almost $1.8 billion of proceeds. In 2011, we repurchased and cancelled US$812 million of long-term debt using cash on hand. In 2010, we repaid $1.5 billion of term credit facilities using proceeds from our non-core asset disposition program.

While we have significantly reduced the size of our energy marketing activities in the last two years, our remaining energy marketing business requires liquidity to support its activities. We require liquidity for working capital and cash or credit lines to fund collateral requirements and to absorb unexpected market or credit losses. The commercial agreements our marketing business enters into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. These agreements can require collateral to be posted if adverse credit-related events, such as reduced credit rating to non-investment grade, occur. We have developed mitigation strategies to significantly reduce our overall exposure if such a downgrade were to occur. We believe our current liquidity is sufficient to fund this exposure, if necessary. Additionally, our exchange-traded contracts require that we provide margin based on daily fluctuations in the value of our contracts. The largest single-day margin call we received during 2011 was $18 million. In evaluating our liquidity requirements, we consider the current requirements of our marketing business as well as additional collateral or other payments that could be required if our credit ratings were reduced.

Future Liquidity

Our future liquidity depends upon cash flow generated from our operations, existing committed credit facilities and our ability to access debt and equity markets. Our 2012 capital investment budget is approximately $2.7 to $3.2 billion, and our cash flow from operations is expected to be $2.8 to $3.3 billion assuming Brent averages US$110/bbl and WTI averages US$95/bbl in 2012. We continue to monitor economic conditions and commodity prices and expect to adjust our capital investment program if we feel it is appropriate.

Changes in commodity prices and exchange rates will impact our cash flow and borrowing requirements. Refer to the Outlook for 2012 section on pages 81 and 82 to see how changes in the above assumptions can impact our cash flow.

At December 31, 2011, we had $845 million in cash, US$3.4 billion of undrawn committed credit facilities and US$367 million of undrawn uncommitted credit facilities. The only debt maturity in the next five years is our US$126 million notes, which mature in March 2015. Given the long term-to-maturity of a significant portion of our debt, we believe we are well positioned to bring our development projects to production and pursue our next generation of growth while preserving our liquidity.

We maintain a US$4 billion shelf prospectus filed in the US and Canada for sales of debt and equity securities, under which we have not issued any debt or equity. This shelf prospectus is due to expire in July 2013.

We are well positioned with our current debt structure. Our only financial debt covenant requires us to maintain a debt to EBITDA ratio of less than 3.5. At December 31, 2011, this ratio was approximately 0.95 times. We do not expect to exceed 3.5 based on our current debt levels and planned operations.

With our expected cash flow streams, commodity price hedging strategies, current liquidity levels, access to debt and equity markets, and flexibility to reduce future capital expenditure programs or sell non-core assets, we expect to be able to fund all planned capital, dividend distributions and debt repayments and meet other obligations that may arise from our oil and gas and energy marketing operations.

In 2011 and 2010, the board declared common share dividends of $0.20.

Financial Assurance Provisions in Commercial Contracts

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

Contractual Obligations, Commitments and Guarantees

We assume various contractual obligations and commitments in the normal course of our operations and financing activities. We have considered these obligations and commitments in assessing our cash requirements, as noted in the above discussion of future liquidity. They include:

		Payments			
(Cdn$ millions)	**Total**	**< 1 year**	**1–3 years**	**4–5 years**	**> 5 years**
Long-Term Debt	4,463	–	–	128	4,335
Cumulative Interest on Long-Term Debt	6,978	301	601	589	5,487
Operating Leases[1]	316	66	110	51	89
Finance Leases	82	4	8	8	62
Energy Commodity Contracts	127	103	23	1	–
Transportation, Processing, and Storage Commitments[1]	461	99	153	80	129
Work Commitments and Purchase Obligations[2]	1,583	1,099	414	34	36
Asset Retirement Obligations	3,481	67	114	246	3,054
Total	**17,491**	**1,739**	**1,423**	**1,137**	**13,192**

1 Payments for operating leases and transportation, processing, and storage commitments are deducted from our cash flow from operating activities.
2 Some of these payments relate to work commitments that we can cancel without penalties or additional fees. Drilling rig commitments are disclosed net of $102 million of subleases.

Contractual obligations can be financial or non-financial. Financial obligations are known future cash payments that we must make under existing contracts, such as debt and lease arrangements. Non-financial obligations are contractual obligations to perform specified activities such as work commitments. Commercial commitments are contingent obligations that become payable only if certain pre-defined events occur. With respect to information in the table above:

- Short-term and long-term debt amounts are included on our December 31, 2011 Consolidated Balance Sheet.
- Operating leases include the minimum lease payment obligations associated with leases for office space, rail cars, vehicles and processing agreements that allow our production to flow through third-party processing facilities.
- Finance leases include pipeline commitments primarily related to production at Long Lake.
- Work commitments include non-discretionary capital spending for drilling, seismic, facilities construction and other development commitments in our operations, including commitments for the Usan development project in Nigeria during 2012. Since the timing of certain payments is difficult to determine with certainty, the table was prepared using our best estimates.
- We have included $546 million in work commitments for drilling rigs we have contracted in the UK and the US Gulf of Mexico over the next two years.
- We have $3,481 million of undiscounted asset retirement obligations after inflation. As of December 31, 2011, the discounted value ($2,076 million) of these estimated obligations was provided for in our Consolidated Financial Statements. Since timing of any payments is difficult to determine with certainty, the table was prepared using our best estimates.
- We have a net pension liability of $227 million for our defined benefit pension plan. This includes the $16 million net obligation for the defined benefit plan, our $91 million share of Syncrude's net pension obligation and $120 million for supplemental pension benefits. Supplemental pension benefits are funded from our operating cash flows and backed with an irrevocable letter of credit.
- We have excluded obligations on our tandem option, stock appreciation rights, performance share units and restricted share units programs as the amount and timing of cash payments are not determinable.
- We have excluded our normal purchase arrangements as they are discretionary and are reflected in our expected cash flow from operating activities and capital expenditures for 2012.
- We have excluded our deferred income tax liabilities as the amount and timing of any cash payment for income taxes is based on taxable income for each fiscal year in the various jurisdictions where we operate. We have also excluded deferred income tax liabilities as they relate to uncertain tax positions, as we cannot provide a reasonable estimate as to if, or when, future payments would be required.

From time to time, we enter into contracts that require us to indemnify parties against certain possible claims, particularly when these contracts relate to the sale of assets. On occasion, we provide indemnifications to the purchaser. Generally, a maximum obligation is not stated; therefore, the overall maximum amount cannot be reasonably estimated. We have not made any significant payments related to these indemnifications. We believe existing indemnifications would not have a material adverse effect on our liquidity, financial condition or results of operations.

CRITICAL ACCOUNTING ESTIMATES

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

Oil and Gas Accounting— Reserves Determination

We deplete our oil and gas costs using the unit-of-production method, as described in Note 2 to our Consolidated Financial Statements. This accounting methodology depends on the estimated remaining reserves. 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. Refer to the Basis of Reserves Estimates on pages 39 to 40 in our Annual Report for a description of our process for estimating reserves.

Reserves estimates are critical to many of our accounting estimates, including:

- determining whether or not an exploratory well has found economically producible reserves. If successful, we capitalize the costs of the well, and, if not, we expense the costs immediately. In 2011, $65 million of our total $513 million spent on exploration drilling was expensed. If all of our exploration drilling was successful in 2011, our net income would have increased by $21 million, net of income tax;
- calculating our unit-of-production depletion rates. Both proved and proved developed reserves estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense. Proved reserves are used where a property is acquired, and proved developed reserves are used where a property is drilled and developed. In 2011, oil and gas depletion of $1,284 million was recorded in depletion, depreciation, amortization and impairment expense. If our proved reserves estimates changed by 10%, our depletion, depreciation, amortization and impairment expense would have changed by approximately $128 million, assuming no other changes to our reserves profiles or impairments as described below; and
- assessing, when necessary, our oil and gas assets for impairment. Estimated future discounted cash flows are determined using proved and probable reserves. The critical estimates used to assess impairment, including the impact of changes in reserves estimates, are discussed below.

Since we do not have any loan covenants directly linked to reserves, it would take a significant decrease in our proved reserves to limit our ability to borrow money under our term credit facilities, as previously described in the Liquidity section of this MD&A.

Impairments

PROPERTY, PLANT AND EQUIPMENT

We evaluate our long-lived assets for impairment when there is an indication that the assets may be impaired. Among other things, these indicators might include falling oil and gas prices, a significant negative revision to our reserve estimates, changes in operating and capital costs or significant or adverse political or regulatory changes. If an indication exists, we assess the asset's recoverable amount to determine if it is impaired. If the recoverable amount of the asset is less than the carrying amount of that asset, impairment is recorded.

Cash flow estimates for our impairment assessments require assumptions about the following primary elements: future prices, future costs, reserves and discount rates. Our estimates of future cash flows are based on our assumptions of long-term prices and operating and development costs and require significant judgments about highly uncertain future events. Historically, oil and gas prices have exhibited significant volatility—over the last five years, prices for Dated Brent and WTI have ranged from US$36/bbl to US$148/bbl and US$32/bbl to US$147/bbl, respectively. Prices for NYMEX gas have ranged from US$2.41/mmbtu to US$13.69/mmbtu. Our forecasts for oil and gas revenues for impairment assessment are based on prices derived from a consensus of future price forecasts amongst industry analysts, our own assessments and existing market future prices. Our estimates of discount rates include consideration of the marketplace and risk of the asset. Given the significant assumptions required and the possibility that actual conditions will differ, we consider the assessments of impairment to be a critical accounting estimate. A change in these estimates would impact all our businesses with the exception of energy marketing.

The relationship between our reserve estimate and the estimated cash flows, and the nature of the property-by-property impairment test is complex. As a result, we are unable to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on our assessment of impairment.

GOODWILL

Goodwill, for impairment testing purposes, is allocated to each of the cash-generating units (CGU) that are expected to benefit from the expenditure. We test goodwill for impairment at least annually or whenever an event or circumstance indicates that goodwill may be impaired. Our goodwill impairment test is based on the assessment of the recoverable amount of the CGU. If the carrying amount of the CGU is greater than its recoverable amount, a goodwill impairment loss equal to the excess is included in net income.

The process of assessing goodwill for impairment requires us to estimate the recoverable amount of our assets using one or more valuation techniques, including present-value calculations of estimated future cash flows. This process involves making various assumptions and judgments about future commodity prices, future activity levels, operating costs and discount rates. Changes in any of these assumptions or judgments could result in an impairment of all or a portion of goodwill.

Asset Retirement Obligations

We are required to remove or remedy the effect of our activities on the environment at our present and former operating sites by dismantling and removing production facilities and remediating the related damage caused. In estimating our future asset retirement obligations, we must make estimates and judgments on activities that will occur many years from now. Additionally, contracts and regulations are often vague and unclear as to what constitutes removal and remediation. Furthermore, the ultimate financial impact is not always clearly known and cannot be reasonably estimated as asset removal and remediation techniques and costs are constantly changing, as are legal, regulatory, environmental, political, safety and other such considerations.

We record asset retirement obligations in our Consolidated Financial Statements by discounting the future value of the estimated retirement obligations associated with our oil and gas wells and facilities and other assets. In arriving at amounts recorded, numerous assumptions and judgments are made on ultimate settlement amounts, inflation factors, discount rates, timing of settlement and expected changes in legal, regulatory, environmental, political and safety environments. The asset retirement obligations we record increase the carrying cost of our property, plant and equipment and accrete with the passage of time.

A change in any one of our assumptions could impact our asset retirement obligations, finance costs, the carrying value of our property, plant and equipment and our DD&A expense.

Income Taxes

We follow the liability method of accounting for income taxes whereby deferred income tax assets and liabilities are recognized based on temporary differences in reported amounts for financial statement and income tax purposes. We carry on business in several countries and, as a result, we are subject to income taxes in numerous jurisdictions. The determination of current income tax is inherently complex, interpretations will vary, and we are required to make certain judgments. Our income tax filings are subject to audits and reassessments and we believe we have adequately provided for all income tax obligations. However, changes in facts, circumstances and interpretations as a result of income tax audits, reassessments, jurisprudence and any new legislation may result in an increase or decrease in our provision for income taxes.

Derivatives and Fair Value Measurements

We enter into contracts to purchase and sell energy commodities (primarily crude oil) and use derivative contracts, including futures, forwards, swaps and options, for hedging and trading purposes (collectively, derivatives). We also use derivatives to manage commodity price risk and foreign currency risk for non-trading purposes. We also carry commodity trading inventory held for trading purposes at fair value.

The fair value of derivative contracts and commodity inventories is estimated. Wherever possible, this estimate is based on quoted market prices and, if not available, on estimates from third-party brokers. We classify the fair value of our derivatives according to a three-level hierarchy based on the amount of observable inputs used to value the instruments. Inputs may be: i) readily observable; ii) market corroborated; or iii) generally unobservable. We utilize valuation techniques that maximize the use of observable inputs wherever possible and minimize the use of unobservable inputs. Another significant assumption that we use in determining the fair value of derivatives is market data or assumptions that market participants would use when pricing the asset or liability, including assumptions about risk.

Our assessment of the significance of a particular input to the fair value measurement may affect the valuation of fair value within the hierarchy. Also for derivative contracts, the time between inception and settlement of the contract may affect fair value. The actual settlement of derivatives could differ materially from the fair value recorded and could impact future operating results. We performed a sensitivity analysis of inputs used to calculate the fair value of the instruments that are based on unobservable inputs. Using reasonably possible alternative assumptions, the fair value of these instruments would change by $8 million (before tax) at December 31, 2011.

NEW ACCOUNTING PRONOUNCEMENTS

IFRS Pronouncements

As part of our transition to IFRS, we adopted IFRS accounting standards that were in effect on January 1, 2011. The impact of adopting IFRS on shareholders' equity, cash flows, net income and comprehensive income is disclosed in Note 26 of the Consolidated Financial Statements for the year ended December 31, 2011. Our 2010 comparative financial information has been restated to be in accordance with our IFRS accounting policies as described in Note 2 of the Consolidated Financial Statements for the year ended December 31, 2011. We determined that the majority of our existing Canadian GAAP oil and gas accounting policies were appropriate under IFRS. Detailed analysis identified differences, the most significant of which are detailed in Note 26 of the Consolidated Financial Statements for the year ended December 31, 2011. Our financial results, operating cash flows and financial position did not materially change as a result of adopting IFRS.

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

- IFRS 7 *Financial Instruments: Disclosures*—in December 2011, the International Accounting Standards Board (IASB) issued final amendments to the disclosure requirements for the offsetting of a financial asset and financial liabilities when offsetting is permitted under IFRS. The disclosure amendments are required to be adopted retrospectively for periods beginning January 1, 2013.
- IFRS 9 *Financial Instruments*—in November 2009, the IASB issued IFRS 9 to address classification and measurement of financial assets. In October 2010, the IASB revised the standard to include financial liabilities. The standard is required to be adopted for periods beginning January 1, 2015. Portions of the standard remain in development and the full impact of the standard will not be known until the project is complete.
- IFRS 10 *Consolidated Financial Statements*—in May 2011, the IASB issued IFRS 10 which provides additional guidance to determine whether an investee should be consolidated. The guidance applies to all investees, including special purpose entities. The standard replaces IAS 27 (which still contains guidance on separate financial statements) and is required to be adopted for periods beginning January 1, 2013. We do not expect the adoption of this standard to impact our results of operations or financial position.
- IFRS 11 *Joint Arrangements*—in May 2011, the IASB issued IFRS 11 which presents a new model for determining whether an entity should account for joint arrangements using proportionate consolidation or the equity method. An entity will have to follow the substance rather than legal form of a joint arrangement and will no longer have a choice of accounting method. The standard is required to be adopted for periods beginning January 1, 2013.
- IFRS 12 *Disclosure of Interests in Other Entities*—in May 2011, the IASB issued IFRS 12 which aggregates and amends disclosure requirements included within other standards. The standard requires companies to provide disclosures about subsidiaries, joint arrangements, associates and unconsolidated structured entities. The standard is required to be adopted for periods beginning January 1, 2013. We expect this standard to result in additional disclosures in our financial statements.
- IFRS 13 *Fair Value Measurement*—in May 2011, the IASB issued IFRS 13 to provide comprehensive guidance for instances where IFRS requires fair value to be used. The standard provides guidance on determining fair value and requires disclosures about those measurements. The standard is required to be adopted for periods beginning January 1, 2013. We do not expect a material impact on our results of operations and financial position.
- IAS 1 *Presentation of Items of Other Comprehensive Income*—in June 2011, the IASB issued amendments to IAS 1 *Presentation of Financial Statements* to separate items of other comprehensive income (OCI) into those that are reclassed to income and those that are not. The standard is required to be adopted for periods beginning on or after July 1, 2012. We do not expect a significant change to our presentation of items of other comprehensive income.
- IAS 19 *Employee Benefits*—in June 2011, the IASB issued amendments to IAS 19 to revise certain aspects of the accounting for pension plans and other benefits.

The amendments eliminate the corridor method of accounting for defined benefit plans, change the recognition pattern of gains and losses and require additional disclosures. The standard is required to be adopted for periods beginning on or after January 1, 2013.

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to normal market risks inherent in the oil and gas business, including commodity price risk, foreign currency rate risk, interest rate risk and credit risk. We recognize these risks and manage our operations to minimize our exposures to the extent practical.

COMMODITY PRICE RISK

Commodity price risk related to crude oil prices is our most significant market risk exposure. Crude oil and natural gas prices are sensitive to numerous worldwide factors, many of which are beyond our control, and are generally sold at contract or posted prices. Changes in crude oil and natural gas prices may significantly affect our results of operations and cash generated from operating activities. Consequently, these changes may also affect the value of our oil, gas properties, our level of spending for exploration and development, and our ability to meet our obligations as they become due.

Our realized crude oil prices are based on various reference prices, primarily WTI and Brent and other prices that generally track the movement of WTI and Brent. Actual prices realized differ from the reference prices to reflect quality differentials and transportation. WTI, Brent and other international reference prices are affected by numerous and complex worldwide factors such as supply and demand fundamentals, economic outlooks, production quotas set by the Organization of Petroleum Exporting Countries and political events. Quality differentials are affected by local supply and demand factors.

We are also exposed to natural gas price movements. Natural gas prices are generally influenced by regional supply and demand fundamentals and, to a lesser extent, local market conditions and oil prices.

In 2011, WTI averaged US$95.12/bbl, reaching a high of US$114.83/bbl and a low of US$74.95/bbl. Dated Brent, on which approximately 70% of our crude oil production is priced, averaged US$111.28/bbl, reaching a high of US$127.02/bbl and a low of US$92.37/bbl. NYMEX natural gas prices averaged US$4.03/mmbtu in 2011, reaching a high of US$4.98/mmbtu and a low of US$2.96/mmbtu. Our sensitivities to commodity prices and the expected impact on our 2012 cash flow from operating activities are included on page 82 of this MD&A.

These sensitivities are based on our estimated 2012 oil and gas production and assume a US/Canadian dollar exchange rate of $0.95. Our estimated oil and gas production range for 2012 is between 185,000 and 220,000 boe/d before royalties, of which approximately 16% is gas.

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

In 2011, we purchased Dated Brent put options to manage the commodity price risk exposure on a portion of our oil production in 2012. These put options established a monthly average Dated Brent floor price of US$65/bbl on about 60,000 bbls/d and an annual average Dated Brent floor price of US$75/bbl on about 40,000 bbls/d of production.

Our energy marketing group's primary focus is to market proprietary crude oil and natural gas production. We also buy and sell third-party production. In order to manage the commodity and foreign exchange price risks that come from this activity, we use financial derivative contracts, including energy-related futures, forwards, swaps and options, as well as currency swaps or forwards.

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

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

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

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

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

FOREIGN CURRENCY RISK

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

- sales of crude oil and natural gas products;
- capital spending and expenses in our oil and gas activities;
- commodity derivative contracts used primarily by our energy marketing group; and
- short-term borrowings and long-term debt.

The US/Canadian dollar exchange rate averaged $1.01 in 2011, ranging from a low of $0.94 to a high of $1.05.

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

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

Our sensitivities to changes in the US/Canadian dollar exchange rate are calculated based on projected revenues, expenses, capital expenditures and US-dollar-denominated long-term debt for 2012. These estimates are based on a Dated Brent price of US$110/bbl, a WTI price of US$95/bbl, a NYMEX natural gas price of US$4.50/mmbtu and a US/Canadian dollar exchange rate of $0.95.

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

We do not have any material exposure to highly inflationary foreign currencies.

INTEREST RATE RISK

We are exposed to changes in interest payments on any floating-rate debt as interest rates fluctuate. Our only floating-rate debt is our term credit facilities which are expected to be used minimally and, therefore, we expect our sensitivity to changes in interest rates in 2012 to be immaterial.

CREDIT RISK

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

- assess the financial strength of our counterparties through a credit analysis process;
- limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;

- routinely monitor credit risk exposures, including sector, geographic and corporate concentrations of credit, and report these to management and the board of directors;
- set and regularly review counterparty credit limits based on rating agency credit ratings and internal assessments of company and industry analysis; and
- use standard agreements where possible that allow for the netting of exposures associated with a single counterparty.

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

At December 31, 2011, only three counterparties individually made up more than 10% of our credit exposure. These counterparties are major integrated oil companies with strong investment-grade ratings. Five counterparties made up more than 5% of our credit exposure.
The following table illustrates the composition of credit exposure by credit rating:

Credit Rating	**December 31 2011**	**December 31 2010**
A or Higher	60%	71%
BBB	31%	20%
Non-investment Grade	9%	9%
Total	**100%**	**100%**

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

OTHER

Non-GAAP Measures

CASH FLOW FROM OPERATIONS

Cash flow from operations is a non-GAAP measure defined as cash flow from operating activities before changes in non-cash working capital and other, and excludes items of a non-recurring nature. We evaluate our performance and that of our business segments based on earnings and cash flow from operations. We consider it a key measure as it demonstrates our ability and the ability of our business segments to generate the cash flow necessary to fund future growth through capital investment and repay debt. Cash flow from operations is unlikely to be comparable with the calculation of similar measures for other companies.

(Cdn$ millions)	**December 31 2011**	**December 31 2010**
Cash Flow from Operating Activities	2,497	2,392
Changes in Non-Cash Working Capital	(255)	(338)
Other	158	128
Impact of Annual Crude Oil Put Options	(32)	(32)
Cash Flow from Operations	**2,368**	**2,150**

NET DEBT

Net debt is a non-GAAP measure defined as long-term debt and short-term borrowings less cash and cash equivalents. We use net debt as a key indicator of our leverage and to monitor the strength of our balance sheet. Net debt is directly tied to our operating cash flows and capital investment. Net debt is unlikely to be comparable with the calculation of similar measures for other companies.

(Cdn$ millions)	**December 31 2011**	**December 31 2010**
Public Senior Notes	3,929	4,647
Subordinated Debt	454	443
Total Debt	**4,383**	**5,090**
Less: Cash and Cash Equivalents	(845)	(1,005)
Total Net Debt	**3,538**	**4,085**

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements at December 31, 2011 and 2010 that would have a material adverse effect on our liquidity, consolidated financial position or results of operations. We use operating leases in the normal course of business as disclosed in Commitments, Contingencies and Guarantees in Note 19 to the Consolidated Financial Statements, which is incorporated herein by reference.

At December 31, 2011, we had outstanding letters of credit supported by $367 million of unsecured term credit facilities and $21 million of uncommitted unsecured credit facilities. The related obligations are recorded on our consolidated balance sheet.

Transactions with Related Parties

As a Canadian foreign private issuer, Nexen provides the disclosure required under Item 1.9 of Form 51-102F1 dealing with "transactions with related parties". Nexen did not have any material related party transactions in 2011. Certain other transactions involving Nexen and certain directors were entered into in 2011 and are described under "Interest of Management and Others in Material Transactions" in our AIF. These are not related party transactions.

Additional Information

Additional information, including our AIF and our Consolidated Financial Statements, is available from our public filings with the Canadian Securities Administrators and the SEC at www.sedar.com and www.sec.gov, respectively or from our website www.nexeninc.com.

On January 31, 2012, there were 528,386,797 common shares issued and outstanding.

FORWARD-LOOKING STATEMENTS

Certain statements in this MD&A constitute "forward-looking statements" (within the meaning of the *United States Private Securities Litigation Reform Act of 1995, as amended*) or "forward-looking information" (within the meaning of applicable Canadian securities legislation). Such statements or information (together "forward-looking statements") are generally identifiable by the forward-looking terminology used such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook", "forecast" or other similar words and include statements relating to or associated with individual wells, regions or projects. Any statements as to possible future crude oil or natural gas prices; future production levels; future royalties and tax levels; future capital expenditures, their timing and their allocation to exploration and development activities; future earnings; future asset acquisitions or dispositions; future sources of funding for our capital program; future debt levels; availability of committed credit facilities; possible commerciality of our projects; development plans or capacity expansions; the expectation that we have the ability to substantially grow production at our oil sands facilities through controlled expansions; the expectation of achieving the production design rates from our oil sands facilities; the expectation that our oil sands production facilities continue to develop better and more sustainable practices; the expectation of cheaper and more technologically advanced operations; the expected design size of our facilities; the expected timing and associated production impact of facility turnarounds and maintenance; the expectation that we can continue to operate our offshore exploration, development and production facilities safely and profitably; future ability to execute dispositions of assets or businesses; future sources of liquidity, cash flows and their uses; future drilling of new wells; ultimate recoverability of current and long-term assets; ultimate recoverability of reserves or resources; expected finding and development costs; expected operating costs; future cost recovery oil revenues from our Yemen operations; the expectation of our ability to comply with the new safety and environmental rules enacted in the US at a minimal incremental cost, and of receiving necessary drilling permits for our US offshore operations; estimates on a per share basis; future foreign currency exchange rates; future expenditures and future allowances relating to environmental matters and our ability to comply with them; dates by which certain areas will be developed, come on stream or reach expected operating capacity; and changes in any of the foregoing are forward-looking statements.

Statements relating to "reserves" or "resources" are forward-looking statements, as they involve the implied assessment, based on estimates and assumptions that the reserves and resources described exist in the quantities predicted or estimated and can be profitably produced in the future.

All of the forward-looking statements in this MD&A are qualified by the assumptions that are stated or inherent in such forward-looking statements. Although we believe that these assumptions are reasonable based on the information available to us on the date such assumptions were made, this list is not exhaustive of the factors that may affect any of the forward-looking statements and the reader should not place an undue reliance on these assumptions and such forward-looking statements. The key assumptions that have been made in connection with the forward-looking statements include the following: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve volumes; commodity price and cost assumptions; the continued availability of adequate cash flow and debt and/or equity financing to fund our capital and operating requirements as needed; and the extent of our liabilities.

We believe the material factors, expectations and assumptions reflected in the forward-looking statements are reasonable, but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

Forward-looking statements are subject to known and unknown risks and uncertainties and other factors, many of which are beyond our control and each of which contributes to the possibility that our forward-looking statements will not occur or that actual results, levels of activity and achievements may differ materially from those expressed or implied by such statements. Such factors include, among others: market prices for oil and gas; our ability to explore, develop, produce, upgrade and transport crude oil and natural gas to markets; ultimate effectiveness of design or design modifications to facilities; the results of exploration and development drilling and related activities; the cumulative impact of oil sands development on the environment; the impact of technology on operations and processes and how new complex technology may not perform as expected; the availability of pipeline and global refining capacity; risks inherent to the operations of any large, complex refinery units, especially the integration between production operations and an upgrader facility; availability of third-party bitumen for use in our oil sands production facilities; labour and material shortages; risks related to accidents, blowouts and spills in connection with our offshore exploration, development and production activities, particularly our deep-water activities; direct and indirect risks related to the imposition of moratoriums, suspensions or cancellations of our offshore exploration, development and production operations, particularly our deep-water activities; the impact of severe weather on our offshore exploration, development and production activities, particularly our deep-water activities; the effectiveness and reliability of our technology in harsh and unpredictable environments; risks related to the actions and financial circumstances of our agents and contractors, counterparties and joint venture partners; volatility in energy trading markets; foreign currency exchange rates; economic conditions in the countries and regions in which we carry on business; governmental actions including changes to taxes or royalties, changes in environmental and other laws and regulations including without limitation, those related to our offshore exploration, development and production activities; renegotiations of contracts; results of litigation, arbitration or regulatory proceedings; political uncertainty, including actions by terrorists, insurgent or other groups, or other armed conflict, including conflict between states; and other factors, many of which are beyond our control. These risks, uncertainties and other factors and their possible impact are discussed more fully in the sections titled "Risk Factors" in our AIF and "Quantitative and Qualitative Disclosures About Market Risk" in this MD&A. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and management's future course of action would depend on our assessment of all information at that time. Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity and achievements. Undue reliance should not be placed on the forward-looking statements contained herein, which are made as of the date hereof as the plans, intentions, assumptions or expectations upon which they are based might not occur or come to fruition. Except as required by applicable securities laws, Nexen undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. Included herein is information that may be considered financial outlook and/or future-oriented financial information (FOFI). Its purpose is to indicate the potential results of our intentions and may not be appropriate for other purposes. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

CONSOLIDATED FINANCIAL STATEMENTS

NEXEN INC. CONSOLIDATED FINANCIAL STATEMENTS

Report of Management	95
Management's Report on Internal Control over Financial Reporting	96
Reports of Independent Registered Chartered Accountants	97
Consolidated Statement of Income	99
Consolidated Balance Sheet	100
Consolidated Statement of Cash Flows	101
Consolidated Statement of Changes in Equity	102
Consolidated Statement of Comprehensive Income	103
Notes to Consolidated Financial Statements	104

REPORT OF MANAGEMENT

February 15, 2012

To the Shareholders of Nexen Inc.

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

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

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

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

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

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

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

REPORTS OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Nexen Inc.

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

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these Consolidated Financial Statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of Consolidated Financial Statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

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

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

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

Opinion

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

Other Matter

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

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants
Calgary, Canada
February 15, 2012

To the Board of Directors and Shareholders of Nexen Inc.

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

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the Consolidated Financial Statements.

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

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

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

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants
Calgary, Canada
February 15, 2012

NEXEN INC.
CONSOLIDATED STATEMENT OF INCOME
FOR THE YEARS ENDED DECEMBER 31

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

See accompanying notes to the Consolidated Financial Statements.

NEXEN INC.
CONSOLIDATED BALANCE SHEET

2011 AND 2010

(Cdn$ millions)	December 31 2011	December 31 2010	January 1 2010
ASSETS			
Current Assets			
Cash and Cash Equivalents	845	1,005	1,700
Restricted Cash	45	40	198
Accounts Receivable (Note 3)	2,247	1,789	2,322
Derivative Contracts (Note 8)	119	158	479
Inventories and Supplies (Note 4)	320	550	680
Other	115	133	172
Assets Held for Sale (Note 23)	–	729	–
Total Current Assets	3,691	4,404	5,551
Non-Current Assets			
Property, Plant and Equipment (Note 5)	15,571	14,579	14,669
Goodwill (Note 6)	291	286	330
Deferred Income Tax Assets (Note 21)	338	160	75
Derivative Contracts (Note 8)	25	116	229
Other Long-Term Assets (Note 7)	152	102	101
TOTAL ASSETS	**20,068**	**19,647**	**20,955**
LIABILITIES			
Current Liabilities			
Accounts Payable and Accrued Liabilities (Note 10)	2,867	2,223	2,591
Current Income Taxes Payable	458	345	179
Derivative Contracts (Note 8)	103	168	482
Liabilities Held for Sale (Note 23)	–	582	–
Total Current Liabilities	3,428	3,318	3,252
Non-Current Liabilities			
Long-Term Debt (Note 11)	4,383	5,090	7,259
Deferred Income Tax Liabilities (Note 21)	1,488	1,487	1,678
Asset Retirement Obligations (Note 14)	2,010	1,516	1,397
Derivative Contracts (Note 8)	24	115	210
Other Long-Term Liabilities (Note 15)	362	307	372
EQUITY (Note 18)			
Nexen Inc. Shareholders' Equity			
Share Capital	1,157	1,111	1,050
Retained Earnings	7,211	6,692	5,704
Cumulative Translation Adjustment	5	(37)	–
Total Nexen Inc. Shareholders' Equity	8,373	7,766	6,754
Canexus Non-Controlling Interests (Note 23)	–	48	33
Total Equity	8,373	7,814	6,787
TOTAL LIABILITIES AND EQUITY	**20,068**	**19,647**	**20,955**

See accompanying notes to the Consolidated Financial Statements.

Approved on behalf of the Board:

(signed) "Kevin J. Reinhart"
Director

(signed) "Thomas C. O'Neill"
Director

NEXEN INC.
CONSOLIDATED STATEMENT OF CASH FLOWS

FOR THE YEARS ENDED DECEMBER 31

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

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

See accompanying notes to the Consolidated Financial Statements.

NEXEN INC.
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
FOR THE YEARS ENDED DECEMBER 31

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

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

See accompanying notes to the Consolidated Financial Statements.

NEXEN INC.
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
FOR THE YEARS ENDED DECEMBER 31

(Cdn$ millions)	2011	2010
Net Income Attributable to Nexen Inc. Shareholders	697	1,127
Other Comprehensive Income (Loss):		
Currency Translation Adjustment:		
Net Translation Gains (Losses) of Foreign Operations	109	(264)
Net Translation Gains (Losses) on US-Denominated Debt Hedging of Foreign Operations[1]	(76)	227
Total Currency Translation Adjustment	33	(37)
Actuarial Losses of Defined Benefit Pension Plans[2]	(73)	(35)
Other Comprehensive Loss	(40)	(72)
Total Comprehensive Income	**657**	**1,055**

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

See accompanying notes to the Consolidated Financial Statements.

NEXEN INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Cdn$ millions, except as noted

1. BASIS OF PRESENTATION

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

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

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

2. ACCOUNTING POLICIES

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

(A) CONSOLIDATION

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

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

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

(B) USE OF ESTIMATES AND JUDGMENTS

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

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

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

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

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

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

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

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

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

(C) CASH AND CASH EQUIVALENTS
Cash and cash equivalents includes short-term, highly liquid investments that mature within three months of their purchase.

(D) RESTRICTED CASH
Restricted cash includes margin deposits relating to our exchange-traded derivative contracts used in our energy marketing business.

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

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

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

(G) PROPERTY, PLANT AND EQUIPMENT (PP&E)
PP&E includes capitalized costs related to our exploration and evaluation expenditures, assets under construction and producing oil and gas properties.

Exploration and Evaluation (E&E) Expenditures

Pre-License Expenditures

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

License and Property Acquisition Expenditures

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

Other Exploration and Evaluation Expenditures

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

Producing Oil and Gas Properties

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

Major Maintenance and Repairs

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

Research and Development

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

Non-Monetary Asset Swaps

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

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

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

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

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

Impairment

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

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

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

(H) CAPITALIZED BORROWING COSTS

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

(I) CARRIED INTEREST

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

(J) GOODWILL

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

(K) FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

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

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

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

Derivatives

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

Hedge accounting

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

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

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

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

(L) PROVISIONS AND CONTINGENCIES

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

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

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

Asset Retirement Obligations and Environmental Expenditures

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

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

(M) PENSION AND OTHER POST-RETIREMENT BENEFITS

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

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

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

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

(N) REVENUE RECOGNITION

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

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

(O) FOREIGN CURRENCY TRANSLATION

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

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

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

(P) TRANSPORTATION

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

(Q) LEASES

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

(R) STOCK-BASED COMPENSATION

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

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

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

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

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

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

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

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

(S) INCOME TAXES

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

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

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

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

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

(T) CHANGES IN ACCOUNTING POLICIES

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

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

- IFRS 7 *Financial Instruments: Disclosures*—in December 2011, the International Accounting Standards Board (IASB) issued final amendments to the disclosure requirements for the offsetting of a financial asset and financial liabilities when offsetting is permitted under IFRS. The disclosure amendments are required to be adopted retrospectively for periods beginning January 1, 2013.
- IFRS 9 *Financial Instruments*—in November 2009, the IASB issued IFRS 9 to address classification and measurement of financial assets. In October 2010, the IASB revised the standard to include financial liabilities. The standard is required to be adopted for periods beginning January 1, 2015. Portions of the standard remain in development and the full impact of the standard will not be known until the project is complete.
- IFRS 10 *Consolidated Financial Statements*—in May 2011, the IASB issued IFRS 10 which provides additional guidance to determine whether an investee should be consolidated. The guidance applies to all investees, including special purpose entities. The standard replaces IAS 27 (which still contains guidance on separate financial statements) and is required to be adopted for periods beginning January 1, 2013. We do not expect the adoption of this standard to impact our results of operations or financial position.
- IFRS 11 *Joint Arrangements*—in May 2011, the IASB issued IFRS 11 which presents a new model for determining whether an entity should account for joint arrangements using proportionate consolidation or the equity method. An entity will have to follow the substance rather than legal form of a joint arrangement and will no longer have a choice of accounting method. The standard also amends IAS 28 to include joint ventures and is required to be adopted for periods beginning January 1, 2013.
- IFRS 12 *Disclosure of Interests in Other Entities*—in May 2011, the IASB issued IFRS 12 which aggregates and amends disclosure requirements included within other standards. The standard requires companies to provide disclosures about subsidiaries, joint arrangements, associates and unconsolidated structured entities. The standard is required to be adopted for periods beginning January 1, 2013. We expect this standard to result in additional disclosures in our financial statements.

- IFRS 13 *Fair Value Measurement*—in May 2011, the IASB issued IFRS 13 to provide comprehensive guidance for instances where IFRS requires fair value to be used. The standard provides guidance on determining fair value and requires disclosures about those measurements. The standard is required to be adopted for periods beginning January 1, 2013. We do not expect a material impact on our results of operations or financial position.
- IAS 1 *Presentation of Items of Other Comprehensive Income*—in June 2011, the IASB issued amendments to IAS 1 *Presentation of Financial Statements* to separate items of other comprehensive income (OCI) between those that are reclassed to income and those that do not. The standard is required to be adopted for periods beginning on or after July 1, 2012. We do not expect a significant change to our presentation of items of other comprehensive income.
- IAS 19 *Employee Benefits*—in June 2011, the IASB issued amendments to IAS 19 to revise certain aspects of the accounting for pension plans and other benefits. The amendments eliminate the corridor method of accounting for defined benefit plans, change the recognition pattern of gains and losses and require additional disclosures. The standard is required to be adopted for periods beginning on or after January 1, 2013.
- IAS 32 *Financial Instruments: Presentation*—in December 2011, the IASB issued amendments to address inconsistencies when applying the offsetting criteria outlined in this standard. These amendments clarify certain of the criteria required to be met in order to permit the offsetting of financial assets and financial liabilities. The standard is required to be adopted retrospectively for periods beginning January 1, 2014.

3. ACCOUNTS RECEIVABLE

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

1 *Includes a general provision of $1 million and a specific provision against certain accounts. In 2011, allowance for doubtful receivables decreased as a result of reassessing prior impairment provisions. In 2010, allowance for doubtful receivables decreased primarily from a reduction in counterparty credit reserves.*
2 *At December 31, 2010, accounts receivable related to our chemicals operations have been included with assets held for sale (see Note 23).*

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

4. INVENTORIES AND SUPPLIES

	December 31 2011	December 31 2010	January 1 2010
Finished Products			
Energy Marketing	230	452	548
Oil and Gas	36	35	25
Other	–	–	12
	266	487	585
Work in Process	6	5	7
Field Supplies	48	58	88
Total[1]	**320**	**550**	**680**

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

5. PROPERTY, PLANT AND EQUIPMENT

(A) CARRYING AMOUNT OF PP&E

	Exploration and Evaluation	Assets Under Construction	Producing Oil & Gas Properties	Corporate and Other	Total
Cost					
As at January 1, 2010	2,393	1,045	20,020	1,849	25,307
Additions	1,092	693	696	243	2,724
Disposals/Derecognitions	(70)	(8)	(1,638)	(122)	(1,838)
Transfers	(82)	78	4	–	–
Exploration Expense	(328)	–	–	–	(328)
Transferred to Held for Sale	–	–	–	(1,207)	(1,207)
Other	36	15	408	(3)	456
Effect of Changes in Exchange Rate	(51)	(75)	(603)	(3)	(732)
As at December 31, 2010	**2,990**	**1,748**	**18,887**	**757**	**24,382**
Additions	1,056	734	693	92	2,575
Disposals/Derecognitions	(303)	–	(2,004)	(18)	(2,325)
Transfers	(1,253)	(216)	1,469	–	–
Exploration Expense	(368)	–	–	–	(368)
Other	65	31	493	–	589
Effect of Changes in Exchange Rate	19	50	294	6	369
As at December 31, 2011	**2,206**	**2,347**	**19,832**	**837**	**25,222**
Accumulated Depreciation, Depletion & Amortization (DD&A)					
As at January 1, 2010	360	11	9,325	942	10,638
DD&A	41	–	1,384	119	1,544
Disposals/Derecognitions	(59)	(8)	(1,378)	(62)	(1,507)
Impairments	–	–	139	–	139
Transferred to Held for Sale	–	–	–	(578)	(578)
Other	1	–	(7)	(5)	(11)
Effect of Changes in Exchange Rate	(12)	(3)	(409)	2	(422)
As at December 31, 2010	**331**	**–**	**9,054**	**418**	**9,803**
DD&A	50	–	1,210	78	1,338
Disposals/Derecognitions	(12)	–	(1,938)	(75)	(2,025)
Impairments	–	–	322	–	322
Other	(6)	–	(8)	–	(14)
Effect of Changes in Exchange Rate	5	–	220	2	227
As at December 31, 2011	**368**	**–**	**8,860**	**423**	**9,651**
Net Book Value					
As at January 1, 2010	2,033	1,034	10,695	907	14,669
As at December 31, 2010	2,659	1,748	9,833	339	14,579
As at December 31, 2011	**1,838**	**2,347**	**10,972**	**414**	**15,571**

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

(B) IMPAIRMENT

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

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

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

(C) ASSET DERECOGNITIONS

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

6. GOODWILL

(A) CARRYING AMOUNT OF GOODWILL

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

	December 31 2011	**December 31 2010**	**January 1 2010**
UK Conventional	284	277	292
Corporate and Other	7	9	38
Total	**291**	**286**	**330**

(B) IMPAIRMENT TESTING OF GOODWILL

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

UK Conventional

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

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

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

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

7. OTHER LONG-TERM ASSETS

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

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

8. FINANCIAL INSTRUMENTS

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

(A) DERIVATIVES

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

Total carrying value of derivative contracts

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

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

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

Derivative contracts related to trading

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

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

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

Derivative contracts related to non-trading activities

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

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

	December 31, 2011				
	Notional Volumes *(bbls/d)*	**Term**	**Average Floor Price** *(US$/bbl)*	**Fair Value** *(Cdn$ millions)*	**Change in Fair Value** *(Cdn$ millions)*
Dated Brent Crude Oil Put Options (annual)	40,000	2012	75	16	(6)
Dated Brent Crude Oil Put Options (monthly)	60,000	2012	65	22	(8)

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

(B) FAIR VALUE OF FINANCIAL INSTRUMENTS

Fair value of derivatives

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

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

Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 consists of financial instruments such as exchange-traded derivatives, and we use information from markets such as the New York Mercantile Exchange.

Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reported date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value, volatility factors and broker quotations, which can be substantially observed or corroborated in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter physical forwards and options, including those that have prices similar to quoted market prices. We obtain information from sources such as the Natural Gas Exchange, independent price publications and over-the-counter broker quotes.

Level 3—Valuations in this level are those with inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value. Level 3 instruments may include items based on pricing services or broker quotes where we are unable to verify the observability of inputs into their prices. Level 3 instruments include longer-term transactions, transactions in less active markets or transactions at locations for which pricing information is not available. In these instances, internally developed methodologies are used to determine fair value, which primarily includes extrapolation of observable future prices to similar locations, similar instruments or later time periods.

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

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

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

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

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

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

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

Fair value of long-term debt

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

9. RISK MANAGEMENT

(A) MARKET RISK

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

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

Commodity price risk

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

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

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

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

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

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

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

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

Foreign currency risk

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

- sales of crude oil and natural gas products;
- capital spending and expenses in our oil and gas activities;
- commodity derivative contracts used primarily by our energy marketing group; and
- short-term borrowings and long-term debt.

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

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

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

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

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

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

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

(B) CREDIT RISK

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

- assess the financial strength of our counterparties through a credit analysis process;
- limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;
- routinely monitor credit risk exposures, including sector, geographic and corporate concentrations of credit, and report these to management and the board of directors;
- set and regularly review counterparty credit limits based on rating agency credit ratings and internal assessments of company and industry analysis; and
- use standard agreements where possible that allow for the netting of exposures associated with a single counterparty.

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

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

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

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

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

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

(C) LIQUIDITY RISK

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

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

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

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

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

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

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

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

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

10. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	December 31 2011	December 31 2010	January 1 2010
Energy Marketing Payables	1,287	1,016	1,366
Accrued Payables	1,035	676	619
Trade Payables	288	164	210
Other	122	147	108
Accrued Interest Payable	78	83	89
Stock-Based Compensation	31	111	173
Dividends Payable	26	26	26
Total[1]	**2,867**	**2,223**	**2,591**

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

11. LONG-TERM DEBT

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

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

(A) TERM CREDIT FACILITIES

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

(B) NOTES, DUE 2013

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

(C) NOTES, DUE 2015

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

(D) NOTES, DUE 2017

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

(E) NOTES, DUE 2019

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

(F) NOTES, DUE 2028

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

(G) NOTES, DUE 2032

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

(H) NOTES, DUE 2035

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

(I) NOTES, DUE 2037

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

(J) NOTES, DUE 2039

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

(K) SUBORDINATED DEBENTURES, DUE 2043

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

(L) LONG-TERM DEBT REPAYMENTS

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

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

(M) DEBT COVENANTS

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

(N) CREDIT FACILITIES

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

Nexen has uncommitted, unsecured credit facilities exclusive to letters of credit of approximately $213 million (US$210 million). We utilized $4 million of these facilities to support outstanding letters of credit at December 31, 2011 (December 31, 2010—nil and January 1, 2010—nil).

12. FINANCE EXPENSE

	2011	2010
Long-Term Debt Interest Expense	304	361
Accretion Expense Related to Asset Retirement Obligations	44	47
Other Interest Expense and Fees	27	34
Total	375	442
Less: Capitalized at 6.7% (2010—5.8%)	(124)	(80)
Total[1]	**251**	**362**

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

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

13. CAPITAL MANAGEMENT

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

- maintaining an appropriate balance between short-term borrowings, long-term debt and equity;
- maintaining sufficient undrawn committed credit capacity to provide liquidity;
- ensuring ample covenant room permitting us to draw on credit lines as required; and
- ensuring we maintain a credit rating that is appropriate for our circumstances.

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

Net Debt[1]	**December 31 2011**	**December 31 2010**	**January 1 2010**
Long-Term Debt	4,383	5,090	7,259
Less: Cash and Cash Equivalents	(845)	(1,005)	(1,700)
Total[2]	**3,538**	**4,085**	**5,559**
Equity[3]	**8,373**	**7,814**	**6,787**

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

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

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

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

14. ASSET RETIREMENT OBLIGATIONS

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

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

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

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

15. OTHER LONG-TERM LIABILITIES

	December 31 2011	December 31 2010	January 1 2010
Defined Benefit Pension Obligations	208	159	139
Finance Lease Obligations	41	42	61
Other	113	106	172
Total[1]	**362**	**307**	**372**

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

16. PENSION AND OTHER POST-RETIREMENT BENEFITS

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

(A) DEFINED BENEFIT PENSION PLANS

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

	2011				
	Nexen			Syncrude	Total
	Registered (Funded)	Supplemental[1] (Unfunded)	Total		
Benefit Obligation					
Beginning of Year	291	97	388	151	539
Service Cost	21	5	26	6	32
Interest Cost	16	5	21	8	29
Plan Participants' Contributions	6	–	6	1	7
Actuarial Loss	25	16	41	29	70
Benefits Paid	(15)	(3)	(18)	(6)	(24)
End of Year[1]	**344**	**120**	**464**	**189**	**653**
Plan Assets					
Beginning of Year	312	–	312	87	399
Expected Return on Plan Assets[2]	21	–	21	7	28
Employer's Contribution	26	3	29	13	42
Plan Participants' Contributions	6	–	6	1	7
Actuarial (Loss) Gain on Plan Assets[2]	(22)	–	(22)	(5)	(27)
Benefits Paid	(15)	(3)	(18)	(5)	(23)
End of Year	**328**	–	**328**	**98**	**426**
Net Pension Liability	**(16)**	**(120)**	**(136)**	**(91)**	**(227)**
Pension Liability					
Accounts Payable and Accrued Liabilities	(6)	(4)	(10)	(9)	(19)
Other Long-Term Liabilities (Note 15)	(10)	(116)	(126)	(82)	(208)
Net Pension Liability	**(16)**	**(120)**	**(136)**	**(91)**	**(227)**
Assumptions *(%)*					
Accrued Benefit Obligation at December 31 Discount Rate			4.50	4.25	
Long-Term Rate of Employee Compensation Increase			4.00	4.50	
Inflation Rate			2.00	5.00	
Benefit Cost for Year Ended December 31 Discount Rate			5.25	4.25	
Long-Term Annual Rate of Return on Plan Assets[3]			6.75	7.30	

	2010				
	Nexen			Syncrude	Total
	Registered (Funded)	Supplemental[1] (Unfunded)	Total		
Projected Benefit Obligation					
Beginning of Year	243	76	319	125	444
Service Cost	17	4	21	5	26
Interest Cost	15	5	20	7	27
Plan Participants' Contributions	6	–	6	1	7
Actuarial Loss (Gain)	26	15	41	19	60
Benefits Paid	(16)	(3)	(19)	(6)	(25)
End of Year[1]	**291**	**97**	**388**	**151**	**539**
Plan Assets					
Beginning of Year	264	–	264	69	333
Expected Return on Plan Assets[2]	20	–	20	6	26
Employer's Contribution	30	3	33	14	47
Plan Participants' Contributions	6	–	6	1	7
Actuarial (Loss) Gain on Plan Assets[2]	8	–	8	2	10
Benefits Paid	(16)	(3)	(19)	(5)	(24)
End of Year	**312**	**–**	**312**	**87**	**399**
Net Pension Liability	**21**	**(97)**	**(76)**	**(64)**	**(140)**
Pension Liability					
Other Long-Term Assets	21	–	21	–	21
Accounts Payable and Accrued Liabilities	–	(2)	(2)	–	(2)
Other Long-Term Liabilities	–	(95)	(95)	(64)	(159)
Net Pension Liability	**21**	**(97)**	**(76)**	**(64)**	**(140)**
Assumptions *(%)*					
Accrued Benefit Obligation at December 31 Discount Rate			5.25	5.25	
Long-Term Rate of Employee Compensation Increase			4.00	4.45	
Inflation Rate			2.50	3.00	
Benefit Cost for Year Ended December 31 Discount Rate			6.00	5.25	
Long-Term Annual Rate of Return on Plan Assets[3]			7.00	7.50	

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

2 *Reconciliation between expected and actual return on plan assets:*

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

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

Defined Benefit Pension Plan Expense

	2011	2010
Nexen		
Cost of Benefits Earned by Employees	26	21
Interest Cost on Benefits Earned	21	20
Expected Return on Plan Assets [1]	(21)	(20)
Net Pension Expense	**26**	**21**
Syncrude [2]		
Cost of Benefits Earned by Employees	6	5
Interest Cost on Benefits Earned	8	7
Expected Return on Plan Assets [3]	(7)	(6)
Net Pension Expense	**7**	**6**
Total Net Pension Expense [4]	**33**	**27**

1 *Actual loss on Nexen plan assets was $1 million (2010—$28 million gain).*
2 *Nexen's share of Syncrude's employee pension plans.*
3 *Actual gain on Syncrude plan assets was $2 million (2010—$8 million gain).*
4 *Net pension expense is reported principally within operating expense and general and administrative expense in the Consolidated Statement of Income.*

(B) PLAN ASSET ALLOCATION AT DECEMBER 31

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

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

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

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

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

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

	Fair Value Measurements at December 31, 2011			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Asset Category				
Cash	2	–	–	2
Pooled Funds				
Canadian Fixed Income	–	114	–	114
Canadian Equity	–	80	–	80
Foreign Equity	–	132	–	132
Total	**2**	**326**	**–**	**328**

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

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

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

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

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

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

(C) DEFINED CONTRIBUTION PENSION PLANS

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

(D) POST-RETIREMENT BENEFITS

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

(E) EMPLOYER FUNDING CONTRIBUTIONS AND BENEFIT PAYMENTS

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

	Expected 2012	2011	2010
Nexen	20	29	33
Syncrude	13	13	14
Total Defined Benefit Contributions	**33**	**42**	**47**

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

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

17. RELATED PARTY DISCLOSURES

(A) MAJOR SUBSIDIARIES

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

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

(B) KEY MANAGEMENT PERSONNEL COMPENSATION

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

	2011	2010
Short-Term Benefits [1]	9	9
Post Employment Benefits [2]	3	4
Share-Based Compensation [3]	(11)	2
Total Compensation	**1**	**15**

1 *Includes employee salary and director's fees, non-equity incentive plan compensation and other short-term compensation.*
2 *Represents the pension current service cost, plus changes in compensation in excess of managerial assumptions, less required member contributions to the plan.*
3 *Stock-based compensation computed for executive management and the board of directors as described in Note 18 and represents change in fair value of outstanding awards.*

18. EQUITY

(A) AUTHORIZED CAPITAL

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

(B) ISSUED COMMON SHARES AND DIVIDENDS

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

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

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

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

(C) TANDEM OPTIONS

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

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

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

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

	Outstanding Tandem and Performance Tandem Options		
	Number of Options *(thousands)*	Weighted Average Exercise Price *($/option)*	Weighted Average Years to Expiry *(years)*
$15.00 to $19.99	3,765	18	3
$20.00 to $24.99	8,405	23	3
$25.00 to $29.99	2,624	28	1
$30.00 to $34.99	35	31	–
$35.00 to $39.99	20	36	–
$40.00 to $44.99	5	40	1
Total	**14,854**		

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

	2011	2010
Option Pricing Model Used for TOPs	Black-Scholes[1]	Black-Scholes[1]
Weighted Average Fair Value *($/option)*	3.86	8.54[2]
Expected Volatility	40%	56%
Weighted-Average Expected Life *(years)*	3.14	3.18
Expected Annual Dividends per Common Share *($/share)*	0.20	0.20
Risk-Free Interest Rate	1.21%	1.83%
Expected Annual Forfeiture Rate	4%	4%

1 *The Monte-Carlo pricing model is used for the performance component of certain instruments. The assumptions used in this model do not differ significantly from those for non-performance TOPs.*
2 *The weighted average fair value of performance tandem options granted in 2010 was $8.17 per option at December 31, 2010.*

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

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

(D) STOCK APPRECIATION RIGHTS

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

	2011		2010	
		Weighted Average Exercise		Weighted Average Exercise
(thousands of shares)	STARs *(thousands)*	Price *($/STAR)*	STARs *(thousands)*	Price *($/STAR)*
Outstanding STARs, Beginning of Year	18,993	25	19,480	25
Granted	377	18	3,354[1]	22
Exercised for Cash	(578)	18	(444)	16
Cancelled	(1,163)	24	(1,806)	27
Expired	(3,222)	31	(1,591)	27
End of Year	**14,407**	**23**	**18,993**	**25**
STARs Exercisable at End of Year	10,512	24	10,938	26
Weighted Average Share Price During the Year	20.80		22.48	

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

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

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

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

	2011	2010
Option Pricing Model Used for STARs	Black-Scholes[1]	Black-Scholes[1]
Weighted Average Fair Value *($/STAR)*	3.48	8.34[2]
Expected Volatility	40%	56%
Weighted-Average Expected Life *(years)*	2.84	2.98
Expected Annual Dividends per Common Share *($/share)*	0.20	0.20
Risk-Free Interest Rate	1.21%	1.83%
Expected Annual Forfeiture Rate	5%	4-5%

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

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

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

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

(E) SHARE UNIT PLANS

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

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

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

19. COMMITMENTS, CONTINGENCIES AND GUARANTEES

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

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

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

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

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

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

20. MARKETING AND OTHER INCOME

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

21. INCOME TAXES

(A) PROVISION FOR (RECOVERY OF) INCOME TAXES

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

(B) DEFERRED INCOME TAX

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

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

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

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

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

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

(D) UNRECOGNIZED DEFERRED TAX ASSETS

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

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

(E) INCOME TAX AUDITS

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

22. EARNINGS PER COMMON SHARE

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

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

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

23. DISPOSITIONS

(A) DISCONTINUED OPERATIONS

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

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

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

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

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

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

(B) ASSET DISPOSITIONS

UK North Sea

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

UK Undeveloped Leases

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

North Dakota/Montana Crude Oil Marketing

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

Natural Gas Energy Marketing

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

Canadian Undeveloped Oil Sand Leases

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

European Gas and Power Marketing

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

24. CASH FLOWS

(A) CHARGES AND CREDITS TO INCOME NOT INVOLVING CASH

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

(B) CHANGES IN NON-CASH WORKING CAPITAL

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

(C) OTHER CASH FLOW INFORMATION

	2011	2010
Interest Paid	305	380
Income Taxes Paid	1,448	951

25. OPERATING SEGMENTS AND RELATED INFORMATION

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

Nexen has the following operating segments:

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

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

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

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

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

Segmented Net Income for the Year Ended December 31, 2011

	Conventional			Oil Sands		Corporate and Other	Total
(Cdn$ millions)	**United Kingdom**	**North America**	**Other Countries[1,2]**	**In Situ**	**Syncrude**		
Net Sales	3,432	499	781	688	713	56	6,169
Marketing and Other Income	21	39	21	–	3	211	295
	3,453	538	802	688	716	267	6,464
Less: Expenses							
Operating	353	156	164	439	287	32	1,431
Depreciation, Depletion, Amortization and Impairment	631	708[3]	76	384[4]	60	54	1,913
Transportation and Other	7	35	28	220	23	112	425
General and Administrative	(8)	74	31	19	1	183	300
Exploration	84	148	134[5]	2	–	–	368
Finance	17	16	2	3	6	207	251
Net Loss on Debt Redemption	–	–	–	–	–	91	91
Net Gain from Dispositions	(38)	–	–	–	–	–	(38)
Income (Loss) from Continuing Operations before Income Taxes	2,407	(599)	367	(379)	339	(412)	1,723
Less: Provision for (Recovery of) Income Taxes	1,697	(164)	68	(95)	84	(262)	1,328
Income (Loss) from Continuing Operations	710	(435)	299	(284)	255	(150)	395
Add: Net Income from Discontinued Operations	–	–	–	–	–	302	302
Net Income (Loss)	**710**	**(435)**	**299**	**(284)**	**255**	**152**	**697**
Capital Expenditures	**583**	**694**	**718[6]**	**397**	**124**	**59**	**2,575**

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

Segmented Net Income for the Year Ended December 31, 2010

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

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

Segmented Assets as at December 31, 2011

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

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

Segmented Assets as at December 31, 2010

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

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

Segmented Assets as at January 1, 2010

(Cdn$ millions)	Conventional United Kingdom	Conventional North America	Conventional Other Countries	Oil Sands In Situ	Oil Sands Syncrude	Corporate and Other	Total
Total Assets	**4,840**	**3,146**	**1,320**	**5,616**	**1,165**	**4,868[1]**	**20,955**
Property, Plant and Equipment							
Cost	5,884	7,464	3,344	5,523	1,390	1,702	25,307
Less: Accumulated DD&A	2,458	4,600	2,387	7	319	867	10,638
Net Book Value	**3,426**	**2,864[2]**	**957[3]**	**5,516[4]**	**1,071**	**835**	**14,669**

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

26. TRANSITION TO IFRS

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

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

Elected Exemptions from Full Retrospective Application

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

(I) BUSINESS COMBINATIONS

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

(II) FAIR VALUE OR REVALUATION AS DEEMED COST

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

(III) CUMULATIVE TRANSLATION DIFFERENCES
We elected to set the cumulative translation account to nil at January 1, 2010. This exemption has been applied to all subsidiaries.

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

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

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

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

Mandatory Exceptions to Retrospective Application

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

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

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

Reconciliations of Canadian GAAP to IFRS

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

RECONCILIATION OF SHAREHOLDERS' EQUITY

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

(I) BORROWING COSTS

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

(II) ASSET RETIREMENT OBLIGATIONS (ARO)

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

(III) EMPLOYEE BENEFITS

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

(IV) STOCK-BASED COMPENSATION (SBC)

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

(V) PROPERTY, PLANT AND EQUIPMENT

Impairment

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

Componentization

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

Major Maintenance

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

(VI) FOREIGN EXCHANGE

Foreign Currency Translation

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

Change in Functional Currency

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

(VII) LONG-TERM DEBT

Canexus Convertible Debentures

Canexus unitholders have the ability to redeem fund units for cash pursuant to the terms of the trust indenture. Under IFRS, these convertible debentures are considered to be financial liabilities containing an embedded derivative. Under Canadian GAAP, the convertible debentures were considered to be compound instruments with an equity component. Accordingly, the equity component and unamortized deferred transaction costs recorded under Canadian GAAP were derecognized on January 1, 2010 and charged to retained earnings. We elected to recognize the convertible debentures at fair value and to recognize changes in fair value in net income during the period of change.

(VIII) INCOME TAXES

Recognition of Deferred Tax Credit

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

Exceptions

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

RECONCILIATION OF NET INCOME

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

(I) BORROWING COSTS

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

(II) ASSET RETIREMENT OBLIGATIONS (ARO)

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

(III) STOCK-BASED COMPENSATION (SBC)

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

(IV) PROPERTY, PLANT AND EQUIPMENT

Impairment

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

Major Maintenance Costs

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

Gain on Sale of Heavy Oil Properties

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

(V) LONG-TERM DEBT

Canexus Convertible Debentures

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

(VI) INCOME TAXES

Recognition of Deferred Tax Credit

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

Other

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

RECONCILIATION OF COMPREHENSIVE INCOME

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

(I) FOREIGN CURRENCY TRANSLATION

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

(II) EMPLOYEE BENEFITS

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

CORPORATE INFORMATION

HEAD OFFICE
801 – 7th Avenue SW
Calgary, Alberta, Canada T2P 3P7
T: 403.699.4000
F: 403.699.5800
www.nexeninc.com

CONTACTS
Investor Relations:
Myles Dougan
Director, Investor Relations
myles_dougan@nexeninc.com
T: 403.699.5346

Kim Woima
Manager, Investor Relations
kim_woima@nexeninc.com
T: 403.699.5821

Media and General Inquiries:
Pierre Alvarez
Vice President, Corporate Relations
pierre_alvarez@nexeninc.com
T: 403.699.5202

EARNINGS RELEASE DATES
Q1 – April 25, 2012
Q2 – July 19, 2012
Q3 – October 25, 2012
Q4 – February 14, 2013

OFFICERS
Francis M. Saville, Q.C.
Chair of the Board

Kevin J. Reinhart
Interim President and Chief Executive Officer

Una M. Power
Interim Chief Financial Officer
and Senior Vice President,
Corporate Planning and
Business Development

Catherine J. Hughes
Executive Vice President,
International Oil and Gas

James T. Arnold
Senior Vice President, Oil Sands

Ronald W. Bailey
Senior Vice President, Canada

Alan O'Brien
Senior Vice President,
General Counsel and Secretary

Kim D. McKenzie
Vice President
and Chief Information Officer

Kevin J. McLachlan
Vice President, Global Exploration

Quinn E. Wilson
Vice President, Human Resources
and Corporate Services

J. Michael Backus
Treasurer

Brendon T. Muller
Controller and Vice President, Insurance

Rick C. Beingessner
Assistant Secretary

C. James Cummings
Assistant Secretary

Annual General Meeting
11:00 a.m. M.D.T.
Wednesday, April 25, 2012
The Hyatt Regency
700 Centre Street SE
Calgary, Alberta, Canada

Stock Symbol—NXY
TSX and NYSE

Preferred Securities
7.35% Subordinated Notes
TSX—NXY.PR.U
NYSE—NXYPRB

Common Share
Transfer Agent and Registrar
CIBC Mellon Trust Company*
Calgary, Toronto, Montreal and Vancouver, Canad

*Canadian Stock Transfer Company Inc. (CST) acts as the administrative agent for CIBC Mellon Trust Company.

Co-Transfer Agent
BNY Mellon Shareowner Services
Jersey City, New Jersey, US

Dividend Reinvestment Plan
The offering circular (and for US residents,
a prospectus) and authorization form
may be obtained by calling CST
at 1.800.387.0825 or at www.canstockta.com

Auditors
Deloitte & Touche LLP, Calgary, Alberta, Canada

Conversions
Natural gas is converted at 6 mcf
per equivalent barrel of oil.

Dollar Amounts
In Canadian dollars unless otherwise stated.

Significant Operating Entities
Nexen Inc.
Nexen Petroleum UK Limited
Nexen Petroleum Offshore USA Inc.
Nexen Marketing
Nexen Petroleum Nigeria Limited
Canadian Nexen Petroleum Yemen
Nexen Oil Sands Partnership

Printed on FSC®-Certified Mohawk Via Smooth 100% post consumer waste. This project resulted in:

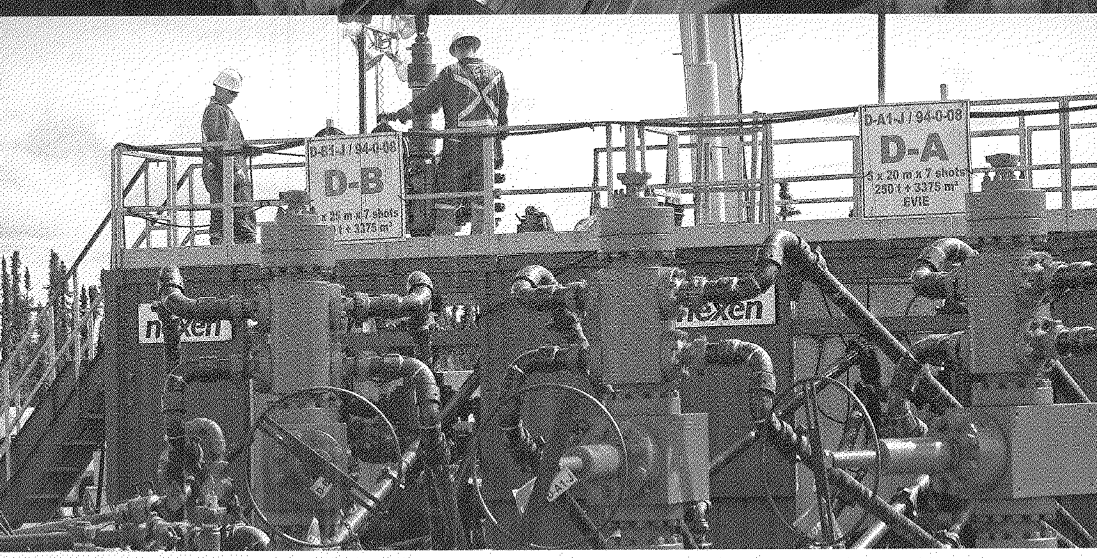
88 trees preserved for the future
255 lbs water-borne waste not created
37,518 gal wastewater flow saved
4,151 lbs solid waste not generated
8,173 lbs net greenhouse gases prevented
62,560,000 BTUs energy not consumed

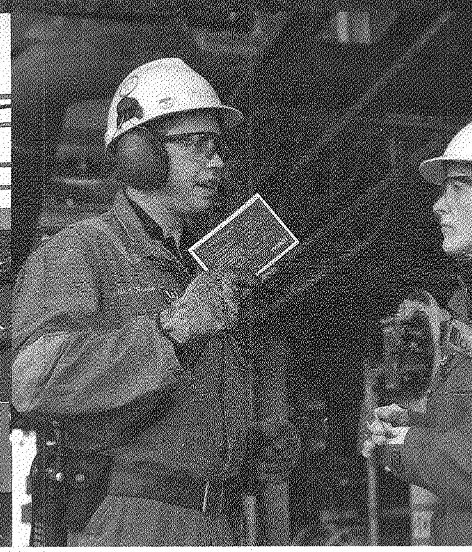
FSC
www.fsc.org
RECYCLED
Paper made from recycled material
FSC® C015495

Please help us preserve our planet. If you choose not to keep this book, please place it in a recycling bin. Thank you.

Design: Karo Group

Printed by: Blanchette Press





Contact Investor Relations
Myles Dougan
Director, Investor Relations
T: 403.699.5346
E: myles_dougan@nexeninc.com

nexen

801 – 7th Avenue SW, Calgary, Alberta, Canada T2P 3P7 T 403.699.4000 F 403.699.5800 www.nexeninc.com