

NEWS RELEASE

For immediate release

Nexen Announces Third Quarter Results

Reduced Buzzard Output Lowers Production; Major Initiatives On Track

Calgary, Alberta, October 27, 2011 – Nexen Inc. (TSX, NYSE: NXY) today reported third quarter 2011 operating and financial results as well as continued progress on our major initiatives. We generated cash flow from operations of \$516 million (\$0.98/share) and net income of \$200 million (\$0.38/share). Our financial results reflect quarterly production of 186,000 barrels of oil equivalent per day (boe/d). Production was below our expectations primarily due to pipeline constraints and longer time to commission the fourth platform at our Buzzard facility in the UK North Sea. Production at Buzzard has since returned to 208,000 boe/d (gross) during October. All other areas met their production expectations during the quarter.

We continued to advance key projects in all areas of operation during the quarter. In the UK North Sea, we obtained all required partner and government approvals to begin development at Golden Eagle. Offshore West Africa, the Usan floating production and storage offloading vessel (FPSO) was successfully moored and final commissioning activities are underway.

At Long Lake, we saw a 6% increase in quarterly bitumen production and we expect to exit the year in the mid 30,000 bbls/d (gross) range. A portion of the increase came from pad 11, which continues to ramp-up as expected. Additionally, we completed drilling on pad 12 and started drilling on pad 13 while advancing plans for subsequent drilling at both Long Lake and Kinosis as part of our strategy to fill the upgrader.

We successfully advanced our shale gas operations in the Horn River basin as we achieved targeted cost reductions on our 9-well pad. Our joint venture process is also proceeding well.

"While we have made good progress against several key initiatives so far this year, our production has been below our expectations due to the downtime at Buzzard," said Marvin Romanow, President and Chief Executive Officer. "With the work complete and the fourth platform commissioned, we are now able to produce from our full well set at Buzzard."

Summary

Financial

- Cash flow from operations of \$516 million (\$0.98/share).
- Net income of \$200 million (\$0.38/share).
- Cash netback from oil & gas operations of \$56.71/boe (\$38.29/boe after tax).
- As expected, net debt increased during the quarter due to higher capital investment and foreign exchange translation impacts. Net debt is down by more than 35% from mid-2010.

Production

- Company-wide production of 186,000 boe/d (164,000 boe/d after royalties) impacted by Buzzard activity, planned maintenance at Scott/Telford and Ettrick, and weather-related downtime in the Gulf of Mexico.
- Buzzard production averaged 114,000 boe/d gross (49,300 boe/d net to Nexen). The scheduled maintenance activity is now complete and the fourth platform is commissioned; field production has been 208,000 boe/d (gross) during October.

- Long Lake bitumen production of 29,500 bbls/d gross (19,200 bbls/d net to Nexen), with October rates averaging about 31,700 bbls/d (20,600 bbls/d net to Nexen) following scheduled maintenance and continued growth in production volumes.
- Production in Yemen continues without interruption.

Project Advancements

- Obtained all partner and government approvals necessary to begin development work at Golden Eagle.
- The Usan FPSO arrived at site offshore West Africa and was moored successfully. Commissioning activities are underway and first production is expected in the first half of 2012.
- Continued drilling at Kakuna and Appomattox in the Gulf of Mexico with results expected over the next few months.
- Successfully completed scheduled maintenance activities at Long Lake, continued the ramp-up of pad 11, completed drilling on pad 12 and continued drilling on pad 13.
- Supported CNOOC Limited's acquisition, subject to regulatory approvals, of our partner at Long Lake, OPTI Canada; CNOOC brings technical and financial capacity to the partnership.
- Our shale gas operations in the Horn River basin advanced as we further reduced our costs on our 9-well pad, where we expect to begin production shortly. Our joint venture process continues to proceed as planned.

Financial Summary

	Three Months Ended			Nine Months Ended	
	Sept. 30	June 30	Sept. 30	Sept. 30	Sept. 30
(Cdn\$ millions unless noted)	2011	2011	2010	2011	2010
WTI (\$US/bbl)	89.76	102.56	76.20	95.48	77.65
Brent (\$US/bbl)	113.47	117.36	76.86	111.94	77.13
NYMEX natural gas (\$US/mmbtu)	4.06	4.37	4.24	4.21	4.54
Average Daily Production (mboe/d)					
Before Royalties	186	204	239	207	246
After Royalties	164	180	213	184	218
Cash flow from operations ¹	516	598	496	1,783	1,594
Per common share (\$/share)	0.98	1.13	0.95	3.38	3.04
Net income	200	252	581	654	967
Per common share (\$/share)	0.38	0.48	1.11	1.24	1.84
Capital investment ²	729	530	629	1,758	2,039
Net debt ³	3,454	2,838	4,497	3,454	4,497

1. For reconciliation of this non-GAAP measure, see Cash Flow from Operations on pg. 10

2. Includes geological and geophysical expenditures.

3. Net debt is defined as long-term debt and short-term borrowings less cash and cash equivalents.

Our portfolio weighting towards unhedged, Brent-priced oil again bolstered our financial results this quarter. Brent averaged US\$113.47 per barrel, a premium of over US\$23 per barrel above WTI. Our strategy of buying put options allows us to benefit when prices rise, while providing partial protection if prices decline below certain levels.

Third quarter cash flow from operations was lower compared to the second quarter, primarily due to scheduled maintenance at Scott and Etrick and weather-related downtime in the Gulf of Mexico. Commodity prices were also slightly lower. Net income was lower due to a \$106 million (after-tax) impairment on some of our non-shale Canadian natural gas properties due to sustained low gas prices.

Compared to the third quarter of 2010, cash flow was higher as higher realized prices more than offset lower production. Net income was lower due to a significant gain on the disposition of our Canadian heavy oil properties in Q3 2010.

We continue to expect our capital investment for the year to be between \$2.4 billion and \$2.7 billion. Net debt rose compared to the prior quarter due to increased drilling and the translation of our US dollar long-term debt into Canadian dollars.

Production

Crude Oil, NGLs and Natural Gas (mboe/d)	Average Daily Quarterly Production before Royalties			Average Daily Quarterly Production after Royalties		
	Q3 2011	Q2 2011	Q3 2010	Q3 2011	Q2 2011	Q3 2010
North Sea	71	84	111	71	84	111
Yemen	32	35	41	17	19	24
United States	21	25	27	19	22	24
Canada – Oil & Gas ¹	19	20	22	17	19	19
Canada – Syncrude	22	20	19	21	18	18
Canada – Bitumen	19	18	17	17	17	16
Other Countries	2	2	2	2	1	1
Total	186	204	239	164	180	213

1. Q3 2010 includes production before royalties of 3 mboe/d and production after royalties of 3 mboe/d from discontinued operations as disclosed in Note 14 to our Unaudited Condensed Consolidated Financial Statements.

Production rates during the third quarter were primarily impacted by activities at our Buzzard platform, scheduled maintenance at Scott/Telford and Ettrick, and weather-related downtime in the Gulf of Mexico.

Buzzard typically produces 195,000-220,000 boe/d (85,000-95,000 boe/d net to Nexen). Production at Buzzard in the third quarter averaged 114,000 boe/d (49,300 boe/d net to Nexen) as we completed scheduled maintenance, commissioned the fourth platform and were constrained by downtime on the third-party owned Forties and Frigg pipelines. While the maintenance was completed on schedule, production was below our expectations due to longer than expected constraints on the Frigg gas export system. These restrictions required us to reduce oil production to minimize gas flaring for six weeks. The export constraints also delayed commissioning of the fourth platform and we experienced higher than expected downtime during commissioning.

During October, the Buzzard facility has been producing at rates of 208,000 boe/d (90,000 boe/d net to Nexen). This production is from the full set of wells with the fourth platform now operational. This platform will allow us to produce all wells, regardless of H2S levels, to keep Buzzard at full rates and enable the future tieback of discoveries with high H2S content. While we anticipate strong production from Buzzard going forward, we also expect some variability as we continue to increase the rate through the fourth platform.

Yemen production reflects natural field declines with no further development drilling activities as we near the end of the primary Masila contract term on December 17th of this year. While we continued our extension efforts, macro political events in the country have made it difficult to make visible progress. At the same time as we continue our discussions, we are preparing for an orderly exit from the country if our renewal discussions are unsuccessful. We remain focused on secure and reliable operations.

In the Gulf of Mexico, we had a few days of downtime on both our shelf and deepwater production as a result of Tropical Storm Lee. This downtime was within our planned allowance for weather-related disruptions and production returned to normal levels shortly thereafter.

The scheduled coker turnaround at Syncrude began September 8th and production has been correspondingly lower in September and October. The maintenance is nearing completion.

At Long Lake, bitumen production averaged 29,500 bbls/d gross (19,200 bbls/d net to Nexen), up 1,600 bbls/d (6%) from the prior quarter and our highest quarterly volume to date. Bitumen production in the month of September was 30,500 bbls/d (19,900 bbls/d net to Nexen), and has averaged 31,700 bbls/d (20,600 bbls/d net to Nexen) during October.

Pad 11 continues to ramp-up in line with expectations as Q3 production was 1,700 bbls/d compared to 900 bbls/d in the second quarter. September production from the pad averaged 2,000 bbls/d at an SOR of 3.2 as we progressed toward our longer-term expectation of 4,000-8,000 bbls/d.

Full-field monthly SOR continues to fall, and reached 4.8 in September. We remain on track to reach production rates in the mid 30,000 bbls per day (gross) by the end of 2011 as volumes from pad 11 and many of our other better-quality existing wells continue to grow while production from the other wells remains stable.

Unit operating costs at Long Lake averaged \$85/bbl in Q3 and include scheduled maintenance costs on the third hot lime softener and the second cogeneration unit. We expect per barrel operating costs to trend downward as

production continues to grow. Operating costs have been high year-to-date due to planned and unplanned maintenance activity, along with initiatives to increase upgrader reliability and improve well performance.

Our upgrader on-stream time and Premium Synthetic Crude (PSC™) yield this quarter were similar to the previous quarter, averaging 82 percent and 70 percent, respectively. Cash flow at Long Lake was lower than the previous quarter primarily due to lower PSC™ prices and lower volumes of third-party bitumen processed.

Long Lake Quarterly Operating Metrics					
	Bitumen Production (Gross)	Steam Injection (Gross)	Unit Operating Costs ¹	Cash Flow	Realized Price
	bbls/d	bbls/d	\$/bbl	\$Cdn millions	\$/bbl
2011					
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™ volumes sold and exclude activities related to third-party bitumen purchased, processed and sold. Unit operating costs includes energy costs.

Guidance Update

Crude Oil, NGLs and Natural Gas (mboe/d)	Average Daily Quarterly Production before Royalties					Average Daily Annual Production before Royalties
	Q1 2011 (actual)	Q2 2011 (actual)	Q3 2011 (actual)	Q3 2011 (prior est.)	Q4 2011 (estimate)	FY 2011 (estimate)
Buzzard	71	49	49	67 – 74	75 – 95	61 – 66
Other UK	32	35	22	23 – 27	24 – 32	28 – 30
Yemen	38	35	32	32 – 34	24 – 33	32 – 35
United States	26	25	21	20 – 24	21 – 24	23 – 24
Canada – Oil & Gas	23	20	19	19 – 21	19 – 22	20 – 21
Canada – Syncrude	23	20	22	19 – 22	20 – 23	21 – 22
Canada – Bitumen	17	18	19	18 – 21	18 – 24	18 – 20
Other Countries	2	2	2	2	2	2
Total	232	204	186	200 – 225	~200 – 230	~200 – 215

Production for the quarter was below our guidance primarily due to longer than expected gas export restrictions and higher than expected variability in Buzzard's operating performance as we commissioned the fourth platform and integrated the new facilities into normal operations.

In the fourth quarter, we expect to see significantly higher volumes at Buzzard as we have returned to normal operating levels, although we expect some fluctuations as we increase the production rate through the new platform. We also expect to see several new sources of production come on-stream, including the Telford and Blackbird tiebacks in the North Sea, and our nine-well shale gas pad in the Horn River. Facility shutdowns will be required at both Telford and Etrick in order to bring the tiebacks on stream. We will be near the low end of our Yemen guidance if we are unsuccessful in obtaining an extension there. We recently shut down the upgrader at Long Lake for repairs to the air separation unit. With the natural gas pipeline installed this summer, we expect to be able to continue to produce and sell bitumen during this shut-down.

In aggregate, we expect our full-year production to be marginally lower than our previous guidance, primarily as a result of lower volumes at Buzzard during the third quarter and potential variability as we increase the rate through the new platform.

Project Advancements

Nexen has a number of opportunities available with several development and appraisal projects underway, and a large resource base to support long-term growth. Near-term projects include new production from a Telford development well; the Blackbird field tie-in; ongoing shale gas drilling; and the Rochelle development. Longer-term projects include Golden Eagle, Appomattox, Knotty Head and Owowo, along with further oil sands and shale gas development.

During the third quarter, we continued to progress our action plan to move these projects into production and cash flow.

Conventional

Offshore West Africa – Development of the Usan field remains on track for first oil in the first half of 2012. The FPSO has arrived in Nigeria and has been successfully moored at site. The process of commissioning the FPSO and connecting the sub-sea wells to the facility has begun and is expected to continue into the early part of next year. At peak rates, the Usan project is capable of producing 180,000 boe/d (36,000 boe/d net to Nexen).

UK North Sea – On October 19th, we received approval from the UK Department of Energy & Climate Change to proceed with the Golden Eagle development, a \$3.3 billion investment (\$1.2 billion net to Nexen) that is expected to produce an estimated 140 mmboe (gross) of proved and probable reserves over an 18-year period.

We are the operator of Golden Eagle and hold a 36.54% working interest in the field. The development has been sanctioned by all of the Golden Eagle co-venturers. Detailed design engineering has commenced and fabrication is scheduled to start before year-end. First oil production is forecast for approximately three years from now, in late 2014, and the development is expected to have an initial gross production rate of up to 70,000 boe/d (26,000 boe/d net to Nexen).

We continue to progress our tieback projects at Telford, Blackbird and Rochelle. We expect to see increased production at Telford and first oil from Blackbird before the end of this year. First production at Rochelle is expected around the end of 2012. Elsewhere in the North Sea, appraisal drilling continues at Polecat, to be followed by an exploration well at Edgware in Q4 2011.

Gulf of Mexico – We returned to drilling in the Gulf of Mexico during the second quarter with the spud of our Kakuna well in late June. We expect to conclude drilling operations at Kakuna in the next few months.

Drilling also started in the third quarter at Appomattox on an appraisal well in the northeast fault block of the structure to follow up on our success in the southern fault block. This well is expected to be complete in the fourth quarter and will be followed by other appraisal and exploration in the area. Nexen has a 20% working interest in Appomattox; the remaining 80% is held by Shell, who is the operator.

Oil Sands

Long Lake – We continue to progress our strategy to increase bitumen production to fill the upgrader. This action plan is focused on the continued drilling of high-quality resource at Long Lake and the advancement of development of a portion of the Kinosis lease.

Our action plan is expected to provide us with an attractive return on capital as each incremental barrel of production contributes significantly to cash flow and profitability given the primarily fixed costs of the Long Lake operation.

In addition to continuing to optimize production from the initial 10 pads, our plans to fill the upgrader include:

	Number of Wells	Expected Rates bbls/d
Pad 11	10	4,000 - 8,000
Pads 12 & 13	18	11,000 - 17,000
Pads 14 & 15	10-12	6,000 - 9,000
Kinosis	25-30	15,000 - 25,000

Drilling on pad 12 was completed during the third quarter, and drilling on pad 13 continues to proceed as planned. These pads have specifically targeted geologically high-quality areas of the lease and our drilling results are confirming our expectations around reservoir quality. We expect to begin steaming pad 12 in spring 2012 and pad 13 in fall 2012. First oil would then follow about three months later, with ramp-up occurring over the following 18 months.

We continue to work through the engineering and regulatory processes for pads 14 and 15 at Long Lake. Similar work is ongoing for 25-30 wells on the Kinosis lease, which is along the southern border of the Long Lake lease. These wells will be drilled in high-quality resource where our extensive information and analysis indicates that their geological characteristics are similar to our current best-producing areas. Drilling on these pads is expected to take place in 2012 or 2013 with first steam at the end of 2013 or in 2014, subject to regulatory approvals.

We are also continuing work on a non-operated SAGD project at Hangingstone, of which we own 25%. Project sanctioning is expected early next year, and first steam would be in 2015. Our share of production at full rates is expected to be about 6,000 bbls/d.

Shale Gas

Northeast British Columbia – Our shale gas program continued to progress during the third quarter as we fraced and completed our nine-well pad. Start-up activities on this pad are currently underway and the production from this pad should allow us to produce to our current facility limit of 50 mmcf/d until additional facility expansions come online a year from now. We reduced our pad costs to under \$700,000/frac on the nine-well pad, 5% below 2010 levels. Since 2009, these costs have dropped almost 70%.

Drilling continues on our first 18-well pad, with start-up scheduled for late 2012 and associated peak field volumes of around 155 mmcf/d expected in early 2013. We expect to be able to reduce our pad costs a further 7-12% on this pad through application of previous learnings and economies of scale.

Our process to secure a JV partner to accelerate value realization for a portion of our northeast BC shale gas asset is proceeding well.

Quarterly Dividend

The Board of Directors has declared the regular quarterly dividend of \$0.05 per common share payable January 1st, 2012, to shareholders of record on December 9th, 2011.

About Nexen

Nexen Inc. is an independent, Canadian-based global energy company, listed on the Toronto and New York stock exchanges under the symbol NXY. Nexen is focused on three growth strategies: oil sands and shale gas in Western Canada and conventional exploration and development primarily in the North Sea, offshore West Africa and deepwater Gulf of Mexico. Nexen adds value for shareholders through successful full-cycle oil and gas exploration and development, and leadership in ethics, integrity, governance and environmental stewardship.

For further information on Appomattox resource disclosure, please refer to our press release dated September 27th, 2010. For more information on our estimates of reserves, please refer to our 2010 Annual Information Form. For more information on our estimates of resource, please refer to our press release dated November 15th, 2010.

For investor relations inquiries, please contact:

Janet Craig
Vice President, Investor Relations
(403) 699-4230

For media and general inquiries, please contact:

Pierre Alvarez
Vice President, Corporate Relations
(403) 699-5202

801 – 7th Ave SW
Calgary, Alberta, Canada T2P 3P7
www.nexeninc.com

Conference Call

Marvin Romanow, President and CEO, and Kevin Reinhart, Executive Vice President and CFO, will discuss the financial and operating results and expectations for the future.

Conference Call Details:

Date: October 27th, 2011

Time: 7:00 a.m. Mountain Time (9:00 a.m. Eastern Time)

To listen to the conference call, please call one of the following:

(416) 340-8527 (Toronto)
(877) 440-9795 (North American toll-free)
(800) 2787-2090 (Global toll-free)

A replay of the call will be available for two weeks starting at 9:00 a.m. Mountain Time, October 27th by calling (905) 694-9451 (Toronto) or (800) 408-3053 (toll-free) passcode 7426133 followed by the pound sign.

We invite you to visit our website at www.nexeninc.com to listen to a live webcast of the conference call. The webcast will be archived under the Investors section of our website.

Forward-Looking Statements

Certain statements in this release 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, natural gas or chemicals 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 operations; the expected timing and associated production impact of facilities turnarounds and maintenance; the expectation that we can continue to operate our offshore exploration, development and production facilities safely and profitably; future ability to execute dispositions of assets or businesses; future sources of liquidity, cash flows and their uses; future drilling of new wells; ultimate recoverability of current and long-term assets; ultimate recoverability of reserves or resources; expected finding and development costs; expected operating costs, future cost recovery oil revenues from our Yemen operations; the expectation of negotiating of an extension to certain of our production sharing agreements; the expectation of our ability to comply with the new safety and environmental rules enacted in the US at a minimal incremental cost, and of receiving necessary drilling permits for our US offshore operations; future demand for chemicals products; 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 release are qualified by the assumptions that are stated or inherent in such forward-looking statements. Although we believe that these assumptions are reasonable, this list is not exhaustive of the factors that may affect any of the forward-looking statements and the reader should not place an undue reliance on these assumptions and such forward-looking statements. The key assumptions that have been made in connection with the forward-looking statements include the following: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; the general

continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve volumes; commodity price and cost assumptions; the continued availability of adequate cash flow and debt and/or equity financing to fund our capital and operating requirements as needed; and the extent of our liabilities. We believe the material factors, expectations and assumptions reflected in the forward-looking statements are reasonable, but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: market prices for oil and gas; our ability to explore, develop, produce, upgrade and transport crude oil and natural gas to markets; ultimate effectiveness of design or design modifications to facilities; the results of exploration and development drilling and related activities; the cumulative impact of oil sands development on the environment; the impact of technology on operations and processes and how new complex technology may not perform as expected; the availability of pipeline and global refining capacity; risks inherent to the operations of any large, complex refinery units, especially the integration between production operations and an upgrader facility; availability of third-party bitumen for use in our oil sands production facilities; labour and material shortages; risks related to accidents, blowouts and spills in connection with our offshore exploration, development and production activities, particularly our deepwater activities; direct and indirect risks related to the imposition of moratoriums, suspensions or cancellations of our offshore exploration, development and production operations, particularly our deepwater activities; the impact of severe weather on our offshore exploration, development and production activities, particularly our deepwater activities; the effectiveness and reliability of our technology in harsh and unpredictable environments; risks related to the actions and financial circumstances of our agents, counterparties, contractors, and joint venture parties; 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. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and management's future course of action would depend on our assessment of all information at that time. Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity and achievements. Undue reliance should not be placed on the forward-looking statements contained herein, which are made as of the date hereof and, except as required by law, Nexen undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement. Readers should also refer to the Risk Factors contained in our 2010 Annual Information form, and to the Quantitative Disclosures about Market Risk and our Forward Looking Statements contained in our 2010 Management Discussion and Analysis.

Cautionary Note to US Investors

In this disclosure, we may refer to "recoverable reserves", "recoverable resources", "recoverable contingent resources" and "prospective resources" which are inherently more uncertain than proved reserves or probable reserves. These terms are not used in our filings with the SEC. Our reserves and related performance measures represent our working interest before royalties, unless otherwise indicated. Please refer to our Annual Information Form available under our profile on SEDAR at www.sedar.com for further reserves disclosure.

Cautionary Note to Canadian Investors

Nexen has received an exemption from the securities regulatory authorities in the various provinces of Canada from certain requirements of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101") that permits us to disclose reserves estimates and related disclosures that have been prepared in accordance with SEC requirements.

As a result of this exemption, Nexen's disclosures may differ from other Canadian companies and investors should note the following fundamental differences between reserves estimates and related disclosures prepared in accordance with SEC requirements and those prepared in accordance with NI 51-101:

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

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

- we use oil equivalents (boe) to express quantities of natural gas and crude oil in a common unit. A conversion ratio of 6 mcf of natural gas to 1 barrel of oil is used. Boe may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead; and

- *because reserves data are based on judgments regarding future events actual results will vary and the variations may be material. Variations as a result of future events are expected to be consistent with the fact that reserves are categorized according to the probability of their recovery.*

Nexen has also received an exemption from NI 51-101 that permits us to forego the requirement to have our reserves and related future net revenue attributable to our reserves evaluated, audited or reviewed by an independent qualified reserves evaluator or auditor. Accordingly, our future net revenue and reserves estimates are based on internal evaluations. Due to the extent and expertise of our internal reserves evaluation resources, our staff's familiarity with our properties and the controls applied to the evaluation process, we believe the reliability of our internally generated reserves estimates is not materially less than would be generated by an independent reserves evaluator.

Resources

The resource estimates contained in this news release were announced on September 27, 2010 and were prepared by qualified reserves evaluators. The estimated contingent and prospective resources in this news release reflects all of our low, high and best case of recoverable resources. A "best estimate" is the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50% confidence level that the actual quantities recovered will equal or exceed the estimate. The 'low estimate' and 'high estimate' are considered to be conservative and optimistic estimates of resources with 90% and 10% confidence respectively. 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.

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 being classified as reserves include but are not limited to: future drilling program and testing results, project sanction, the cost and effectiveness of fracturing 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.

Cautionary statement: *In the case of discovered resources or a subcategory of discovered resources other than reserves, there is no certainty that it will be commercially viable to produce any portion of the resources. In the case of undiscovered resources or a subcategory of undiscovered 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.*

Nexen Inc.
Financial Highlights

(Cdn\$ millions)	Three Months Ended			Nine Months Ended	
	Sept 30 2011	June 30 2011	Sept 30 2010	Sept 30 2011	Sept 30 2010
Net Sales ¹	1,399	1,507	1,452	4,546	4,447
Cash Flow from Operations ¹	516	598	496	1,783	1,594
Per Common Share (\$/share)	0.98	1.13	0.95	3.38	3.04
Net Income ¹	200	252	581	654	967
Per Common Share (\$/share)	0.38	0.48	1.11	1.24	1.84
Capital Investment ²	729	530	629	1,758	2,039
Net Debt ³	3,454	2,838	4,497	3,454	4,497
Common Shares Outstanding (millions of shares)	527.4	527.0	525.0	527.4	525.0

¹ Includes discontinued operations as discussed in Note 14 to our Unaudited Condensed Consolidated Financial Statements.

² Includes oil and gas development, exploration, and expenditures for other property, plant and equipment.

³ Net debt is defined as long-term debt and short-term borrowings less cash and cash equivalents.

Cash Flow from Operations ¹

(Cdn\$ millions)	Three Months Ended			Nine Months Ended	
	Sept 30 2011	June 30 2011	Sept 30 2010	Sept 30 2011	Sept 30 2010
Conventional Oil & Gas					
United Kingdom	645	699	670	2,231	1,995
North America ²	50	91	63	206	292
Other Countries ³	86	115	101	297	292
Oil Sands					
In Situ	(4)	6	(42)	(17)	(119)
Syncrude	106	103	58	316	203
	883	1,014	850	3,033	2,663
Interest, Marketing and Other Corporate Items ²	(62)	(90)	(127)	(237)	(401)
Income Taxes ⁴	(305)	(326)	(227)	(1,013)	(668)
Cash Flow from Operations ¹	516	598	496	1,783	1,594

¹ Defined as cash flow from operating activities before changes in non-cash working capital and other. We evaluate our performance and that of our business segments based on earnings and cash flow from operations. Cash flow from operations is a non-GAAP term that represents cash generated from operating activities before changes in non-cash working capital and other. We consider it a key measure as it demonstrates our ability to generate the cash flow necessary to fund future growth through capital investment. Cash flow from operations may not be comparable with the calculation of similar measures for other companies.

(Cdn\$ millions)	Three Months Ended			Nine Months Ended	
	Sept 30 2011	June 30 2011	Sept 30 2010	Sept 30 2011	Sept 30 2010
Cash Flow from Operating Activities	288	1,014	705	2,038	2,050
Changes in Non-Cash Working Capital Including Income Taxes and Interest Payable	198	(419)	(215)	(287)	(413)
Other	38	11	14	56	(13)
Impact of Annual Crude Oil Put Options	(8)	(8)	(8)	(24)	(30)
Cash Flow from Operations	516	598	496	1,783	1,594
Weighted-average Number of Common Shares Outstanding (millions of shares)	527.4	527.0	525.0	526.9	524.4
Cash Flow from Operations Per Common Share (\$/share)	0.98	1.13	0.95	3.38	3.04

² Includes discontinued operations as discussed in Note 14 to our Unaudited Condensed Consolidated Financial Statements.

³ After in-country cash taxes in Yemen of \$46 million for the three months ended September 30, 2011 (June 30, 2011 – \$58 million; September 30, 2010 – \$43 million) and \$146 million for the nine months ended September 30, 2011 (September 30, 2010 – \$125 million).

⁴ Excludes in-country cash taxes in Yemen.

Nexen Inc.
Production Volumes (before royalties) ¹

	Three Months Ended Sept 30		Nine Months Ended Sept 30	
	2011	2010	2011	2010
Crude Oil and Liquids (mbbls/d)				
United Kingdom	66.8	106.3	80.4	103.4
Yemen	32.3	41.6	35.1	41.8
Oil Sands – Syncrude	21.6	19.1	21.7	20.7
Oil Sands – Long Lake Bitumen	19.2	16.7	18.0	15.0
United States	7.7	9.9	8.6	9.9
Canada ²	–	2.9	–	10.0
Other Countries	1.6	2.0	1.7	2.1
	<u>149.2</u>	<u>198.5</u>	<u>165.5</u>	<u>202.9</u>
Natural Gas (mmcf/d)				
United Kingdom	26	27	32	36
United States	81	102	94	100
Canada ²	111	113	123	124
	<u>218</u>	<u>242</u>	<u>249</u>	<u>260</u>
Total Production (mboe/d)	<u>186</u>	<u>239</u>	<u>207</u>	<u>246</u>

Production Volumes (after royalties)

	Three Months Ended Sept 30		Nine Months Ended Sept 30	
	2011	2010	2011	2010
Crude Oil and Liquids (mbbls/d)				
United Kingdom	66.4	106.3	80.2	103.4
Yemen	17.4	23.5	18.9	22.9
Oil Sands – Syncrude	20.6	17.9	20.2	19.1
Oil Sands – Long Lake Bitumen	17.3	16.0	16.6	14.3
United States	6.8	8.9	7.7	8.9
Canada ²	–	2.3	–	7.7
Other Countries	1.5	1.9	1.6	2.0
	<u>130.0</u>	<u>176.8</u>	<u>145.2</u>	<u>178.3</u>
Natural Gas (mmcf/d)				
United Kingdom	26	27	32	36
United States	71	89	81	86
Canada ²	104	104	117	114
	<u>201</u>	<u>220</u>	<u>230</u>	<u>236</u>
Total Production (mboe/d)	<u>164</u>	<u>213</u>	<u>184</u>	<u>218</u>

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 Includes the following production from discontinued operations in Note 14 to our Unaudited Condensed Consolidated Financial Statements.

	Three Months Ended Sept 30		Nine Months Ended Sept 30	
	2011	2010	2011	2010
Before Royalties				
Crude Oil and NGLs (mbbls/d)	–	2.9	–	10.0
Natural Gas (mmcf/d)	–	2.2	–	8.3
After Royalties				
Crude Oil and NGLs (mbbls/d)	–	2.3	–	7.7
Natural Gas (mmcf/d)	–	2.1	–	7.2

Nexen Inc.
Oil and Gas Prices and Cash Netback ¹

(all dollar amounts in Cdn\$ unless noted)	Quarters – 2011				Quarters – 2010				Total Year
	1 st	2 nd	3 rd	4 th	1 st	2 nd	3 rd	4 th	2010
PRICES:									
Brent Crude Oil (US\$/bbl)	104.97	117.36	113.47		76.23	78.30	76.86	86.48	79.47
WTI Crude Oil (US\$/bbl)	94.10	102.56	89.76		78.71	78.03	76.20	85.12	79.52
Nexen Average – Oil (Cdn\$/bbl)	98.37	110.28	103.98		78.00	76.23	77.03	84.47	78.94
NYMEX Natural Gas (US\$/mmbtu)	4.20	4.37	4.06		5.04	4.34	4.24	3.97	4.39
AECO Natural Gas (Cdn\$/mcf)	3.58	3.54	3.53		5.08	3.66	3.52	3.41	3.92
Nexen Average – Gas (Cdn\$/mcf)	4.51	4.75	4.36		5.37	4.42	4.18	4.16	4.54
NETBACKS ¹:									
United Kingdom									
Crude Oil:									
Sales (mmbbls/d)	104.2	73.3	75.2		106.5	102.1	103.9	110.0	105.6
Price Received (\$/bbl)	99.97	110.55	106.71		77.24	77.18	77.45	83.88	79.02
Natural Gas:									
Sales (mmcf/d)	36	37	26		33	41	29	38	36
Price Received (\$/mcf)	7.29	8.20	7.28		4.81	4.80	5.11	6.34	5.28
Total Sales Volume (mboe/d)	110.2	79.5	79.5		112.1	109.0	108.8	116.3	111.5
Price Received (\$/boe)	96.91	105.76	103.31		74.84	74.12	75.35	81.37	76.51
Operating Costs	9.85	8.48	14.46		7.60	7.85	8.41	9.19	8.28
Netback	87.06	97.28	88.85		67.24	66.27	66.94	72.18	68.23
United States									
Crude Oil:									
Sales (mmbbls/d)	9.2	8.9	7.7		9.8	9.9	9.8	10.1	9.9
Price Received (\$/bbl)	91.39	101.89	96.00		79.12	73.60	73.72	80.41	76.73
Natural Gas:									
Sales (mmcf/d)	103	96	81		101	95	102	99	99
Price Received (\$/mcf)	4.36	4.42	4.27		6.00	5.14	4.70	4.05	4.97
Total Sales Volume (mboe/d)	26.3	24.9	21.2		26.6	25.8	26.9	26.6	26.5
Price Received (\$/boe)	48.91	53.56	50.72		51.92	47.23	44.85	45.55	47.35
Royalties & Other	5.65	6.11	5.63		4.92	4.86	5.10	(0.63)	3.55
Operating Costs	10.43	10.72	11.18		8.96	10.90	9.44	10.78	10.02
Netback	32.83	36.73	33.91		38.04	31.47	30.31	35.40	33.78
Canada – Natural Gas									
Sales (mmcf/d) ²	97	85	79		124	121	107	104	114
Price Received (\$/mcf)	3.65	3.62	3.51		5.02	3.72	3.43	3.48	3.94
Royalties & Other	0.28	0.24	0.27		0.40	0.34	0.26	0.24	0.32
Operating Costs	1.70	1.54	1.65		1.70	1.89	1.90	1.55	1.76
Netback	1.67	1.84	1.59		2.92	1.49	1.27	1.69	1.86
Yemen									
Sales (mmbbls/d)	34.9	39.3	31.8		47.3	39.3	43.5	38.8	42.2
Price Received (\$/bbl)	101.57	111.77	107.98		80.39	80.50	79.33	87.82	81.86
Royalties & Other	46.98	52.26	49.72		37.52	36.65	34.75	37.72	36.65
Operating Costs	10.75	9.18	13.20		9.67	10.01	9.46	12.05	10.25
In-country Taxes	13.48	16.26	15.49		10.14	10.97	10.70	11.52	10.80
Netback	30.36	34.07	29.57		23.06	22.87	24.42	26.53	24.16

¹ Defined as average sales price less royalties and other, operating costs, and in-country taxes in Yemen.

² Excludes sales related to shale gas activities in north eastern British Columbia.

Nexen Inc.
Oil and Gas Cash Netback ¹ (continued)

(all dollar amounts in Cdn\$ unless noted)	Quarters – 2011				Quarters – 2010				Total Year
	1 st	2 nd	3 rd	4 th	1 st	2 nd	3 rd	4 th	2010
Other Countries									
Sales (mbbls/d)	1.8	1.7	1.6		2.3	2.1	2.0	1.9	2.1
Price Received (\$/bbl)	93.52	106.57	101.28		78.88	74.77	75.93	77.63	76.83
Royalties & Other	6.22	6.93	6.57		5.72	5.28	5.22	5.24	5.37
Operating Costs	8.11	10.19	8.58		5.58	7.42	6.98	8.19	6.99
Netback	79.19	89.45	86.13		67.58	62.07	63.73	64.20	64.47
In Situ ²									
Sales (mbbls/d)	12.9	14.3	11.8		6.6	10.3	11.9	12.1	10.3
Price Received (\$/bbl)	89.82	108.78	94.15		81.04	74.08	70.64	82.99	77.07
Royalties & Other	3.58	6.05	5.07		4.37	2.98	3.08	3.81	3.65
Operating Costs	89.43	95.34	85.42		154.00	89.95	84.75	85.61	100.09
Netback ²	(3.19)	7.39	3.66		(77.33)	(18.84)	(17.19)	(6.43)	(26.67)
Syncrude									
Sales (mbbls/d)	23.2	20.4	21.6		19.5	23.4	19.1	22.8	21.2
Price Received (\$/bbl)	94.60	111.79	97.65		83.55	77.93	78.27	85.12	81.23
Royalties & Other	4.30	13.82	4.65		7.09	6.37	4.82	6.72	6.27
Operating Costs	36.11	39.98	37.10		35.84	32.67	38.06	31.65	34.34
Netback	54.19	57.99	55.90		40.62	38.89	35.39	46.75	40.62
Company-Wide									
Oil and Gas Sales (mboe/d)	225.5	194.3	180.7		249.1	243.1	232.9	235.9	240.2
Price Received (\$/boe)	85.98	95.26	90.70		70.16	67.56	68.23	74.49	70.11
Royalties & Other	8.74	13.42	10.47		9.38	8.05	7.96	7.13	8.16
Operating & Other Costs ²	17.32	18.68	20.80		14.93	15.85	15.42	15.97	15.48
In-country Taxes	2.08	3.29	2.72		1.92	1.76	2.00	1.89	1.90
Netback	57.84	59.87	56.71		43.92	41.90	42.85	49.50	44.57

¹ Defined as average sales price less royalties and other, operating costs, and in-country taxes in Yemen.

² 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.

Nexen Inc.
Unaudited Condensed Consolidated Statement of Income
For the Three and Nine Months Ended September 30

	Three Months		Nine Months	
	Ended September 30		Ended September 30	
(Cdn\$ millions, except per share amounts)	2011	2010	2011	2010
Revenues and Other Income				
Net Sales	1,399	1,321	4,504	3,973
Marketing and Other Income (Note 13)	125	117	266	304
	<u>1,524</u>	<u>1,438</u>	<u>4,770</u>	<u>4,277</u>
Expenses				
Operating	356	334	1,060	978
Depreciation, Depletion, Amortization and Impairment	409	435	1,114	1,136
Transportation and Other	110	130	289	464
General and Administrative	23	115	204	264
Exploration	59	56	278	199
Finance (Note 8)	59	87	193	273
Loss on Debt Redemption and Repurchase (Note 7)	—	—	91	—
Net Loss from Dispositions	—	259	—	179
	<u>1,016</u>	<u>1,416</u>	<u>3,229</u>	<u>3,493</u>
Income from Continuing Operations before Provision for Income Taxes	<u>508</u>	<u>22</u>	<u>1,541</u>	<u>784</u>
Provision for (Recovery of) Income Taxes				
Current	351	270	1,159	793
Deferred	(43)	(194)	30	(304)
	<u>308</u>	<u>76</u>	<u>1,189</u>	<u>489</u>
Net Income (Loss) from Continuing Operations	200	(54)	352	295
Net Income from Discontinued Operations, Net of Tax (Note 14)	—	635	302	672
Net Income Attributable to Nexen Inc. Shareholders	<u>200</u>	<u>581</u>	<u>654</u>	<u>967</u>
Earnings (Loss) Per Common Share from Continuing Operations (\$/share)				
Basic	<u>0.38</u>	<u>(0.10)</u>	<u>0.67</u>	<u>0.56</u>
Diluted	<u>0.32</u>	<u>(0.10)</u>	<u>0.61</u>	<u>0.54</u>
Earnings Per Common Share (\$/share)				
Basic	<u>0.38</u>	<u>1.11</u>	<u>1.24</u>	<u>1.84</u>
Diluted	<u>0.32</u>	<u>1.07</u>	<u>1.16</u>	<u>1.77</u>

See accompanying notes to the Unaudited Condensed Consolidated Financial Statements.

Nexen Inc.
Unaudited Condensed Consolidated Balance Sheet

(Cdn\$ millions)	September 30 2011	December 31 2010	January 1 2010
Assets			
Current Assets			
Cash and Cash Equivalents	1,025	1,005	1,700
Restricted Cash	52	40	198
Accounts Receivable (Note 3)	1,870	1,789	2,322
Derivative Contracts	106	149	466
Inventories and Supplies (Note 4)	347	550	680
Other	175	142	185
Assets Held for Sale (Note 14)	—	729	—
Total Current Assets	3,575	4,404	5,551
Non-Current Assets			
Property, Plant and Equipment (Note 5)	15,451	14,579	14,669
Goodwill	297	286	330
Deferred Income Tax Assets	231	160	75
Derivative Contracts	8	116	225
Other Long-Term Assets	167	102	105
Total Assets	19,729	19,647	20,955
Liabilities			
Current Liabilities			
Accounts Payable and Accrued Liabilities (Note 6)	2,877	2,459	2,681
Derivative Contracts	85	168	456
Accrued Interest Payable	63	83	89
Dividends Payable	26	26	26
Liabilities Held for Sale (Note 14)	—	582	—
Total Current Liabilities	3,051	3,318	3,252
Non-Current Liabilities			
Long-Term Debt (Note 7)	4,479	5,090	7,259
Deferred Income Tax Liabilities	1,712	1,487	1,678
Asset Retirement Obligations (Note 9)	1,725	1,516	1,397
Derivative Contracts	16	115	210
Other Long-Term Liabilities	320	307	372
Equity (Note 11)			
Nexen Inc. Shareholders' Equity			
Common Shares	1,150	1,111	1,050
Retained Earnings	7,268	6,692	5,704
Accumulated Other Comprehensive Income (Loss)	8	(37)	—
Total Nexen Inc. Shareholders' Equity	8,426	7,766	6,754
Canexus Non-Controlling Interest (Note 14)	—	48	33
Total Equity	8,426	7,814	6,787
Commitments, Contingencies and Guarantees (Note 12)			
Total Liabilities and Equity	19,729	19,647	20,955

See accompanying notes to Unaudited Condensed Consolidated Financial Statements.

Nexen Inc.
Unaudited Condensed Consolidated Statement of Cash Flows
For the Three and Nine Months Ended September 30

(Cdn\$ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
Operating Activities				
Net Income (Loss) from Continuing Operations	200	(54)	352	295
Net Income from Discontinued Operations	–	635	302	672
Charges and Credits to Income not Involving Cash (Note 15)	662	245	2,194	1,547
Exploration Expense	59	56	278	199
Income Taxes Paid	(646)	(376)	(1,106)	(626)
Interest Paid	(88)	(103)	(218)	(293)
Changes in Non-Cash Working Capital (Note 15)	139	316	292	243
Other	(38)	(14)	(56)	13
	288	705	2,038	2,050
Financing Activities				
Repayment of Short-Term Borrowings	–	(156)	–	–
Repayment of Term Credit Facilities, Net	–	(463)	–	(1,540)
Repayment of Long-Term Debt (Note 7)	–	–	(871)	–
Proceeds from Canexus Long-Term Debt, Net	–	56	5	124
Dividends Paid on Common Shares	(26)	(26)	(78)	(78)
Issue of Common Shares and Exercise of Tandem Options for Shares	8	9	39	44
Other	1	(8)	(3)	(28)
	(17)	(588)	(908)	(1,478)
Investing Activities				
Capital Expenditures				
Exploration, Evaluation, and Development	(683)	(567)	(1,618)	(1,803)
Capitalized Interest Paid	(33)	(24)	(90)	(64)
Corporate and Other	(13)	(38)	(50)	(172)
Proceeds from Dispositions	1	950	475	1,046
Changes in Restricted Cash	1	(43)	(10)	40
Changes in Non-Cash Working Capital (Note 15)	69	(105)	184	(30)
Other	–	(1)	(75)	(8)
	(658)	172	(1,184)	(991)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	100	(49)	74	(71)
Increase (Decrease) in Cash and Cash Equivalents	(287)	240	20	(490)
Cash and Cash Equivalents – Beginning of Period	1,312	970	1,005	1,700
Cash and Cash Equivalents – End of Period ¹	1,025	1,210	1,025	1,210

¹ Cash and cash equivalents at September 30, 2011 consists of cash of \$277 million and short-term investments of \$748 million (September 30, 2010 – cash of \$211 million and short-term investments of \$999 million).

See accompanying notes to the Unaudited Condensed Consolidated Financial Statements.

Nexen Inc.
Unaudited Condensed Consolidated Statement of Changes in Equity
For the Three and Nine Months Ended September 30

(Cdn\$ millions)	Three Months		Nine Months	
	Ended September 30 2011	2010	Ended September 30 2011	2010
Common Shares , Beginning of Period	1,142	1,088	1,111	1,050
Issue of Common Shares	8	9	39	41
Exercise of Tandem Options for Shares	–	–	–	3
Accrued Liability Relating to Tandem Options Exercised for Common Shares	–	–	–	3
Balance at End of Period	<u>1,150</u>	<u>1,097</u>	<u>1,150</u>	<u>1,097</u>
Retained Earnings , Beginning of Period	7,094	6,038	6,692	5,704
Net Income Attributable to Nexen Inc. Shareholders	200	581	654	967
Dividends on Common Shares (Note 11)	(26)	(26)	(78)	(78)
Balance at End of Period	<u>7,268</u>	<u>6,593</u>	<u>7,268</u>	<u>6,593</u>
Accumulated Other Comprehensive Loss , Beginning of Period	(55)	(5)	(37)	–
Other Comprehensive Income (Loss) Attributable to Nexen Inc. Shareholders	63	(9)	45	(14)
Balance at End of Period	<u>8</u>	<u>(14)</u>	<u>8</u>	<u>(14)</u>
Canexus Non-Controlling Interests , Beginning of Period	–	42	48	33
Net Income Attributable to Non-Controlling Interests	–	5	1	4
Distributions Declared to Non-Controlling Interests	–	(5)	–	(12)
Issue of Partnership Units to Non-Controlling Interests	–	6	–	23
Disposition of Canexus (Note 14)	–	–	(49)	–
Balance at End of Period	<u>–</u>	<u>48</u>	<u>–</u>	<u>48</u>

See accompanying notes to the Unaudited Condensed Consolidated Financial Statements.

Nexen Inc.
Unaudited Condensed Consolidated Statement of Comprehensive Income
For the Three and Nine Months Ended September 30

(Cdn\$ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
Net Income Attributable to Nexen Inc. Shareholders	200	581	654	967
Other Comprehensive Income (Loss), Net of Income Taxes:				
Foreign Currency Translation Adjustment				
Net Gains (Losses) on Investment in Self-Sustaining Foreign Operations	339	(154)	200	(88)
Net Gains (Losses) on Foreign-Denominated Debt Hedging of Self-Sustaining Foreign Operations ¹	(276)	145	(155)	74
Other Comprehensive Income (Loss) Attributable to Nexen Inc. Shareholders	63	(9)	45	(14)
Total Comprehensive Income	263	572	699	953

¹ Net of income tax recovery for the three months ended September 30, 2011 of \$39 million (2010 – net of income tax expense of \$21 million) and net of income tax recovery for the nine months ended September 30, 2011 of \$22 million (2010 – net of income tax expense of \$10 million).

See accompanying notes to the Unaudited Condensed Consolidated Financial Statements.

Nexen Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

Cdn\$ millions, except as noted

1. BASIS OF PRESENTATION

Nexen Inc. (Nexen, we or our) is an independent, global energy company with operations in the North Sea, Gulf of Mexico, offshore West Africa, Canada, Yemen and Colombia. Nexen is incorporated and domiciled in Canada. Nexen's shares are publicly traded on both the Toronto Stock Exchange and the New York Stock Exchange.

These Unaudited Condensed Consolidated Financial Statements for the three and nine months ended September 30, 2011 have been prepared in accordance with International Accounting Standard (IAS) 34 *Interim Financial Reporting*. The Unaudited Condensed Consolidated Financial Statements do not include all of the information required for annual financial statements. Amounts relating to the three and nine months ended September 30, 2010 and as at 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 International Financial Reporting Standards ("IFRS") (see Note 2). Reconciliations and descriptions relating to the transition from Canadian GAAP to IFRS are included in Note 17.

The Unaudited Condensed Consolidated Financial Statements were authorized for issue on October 26, 2011 and should be read in conjunction with the Audited Consolidated Financial Statements for the year ended December 31, 2010, which have been prepared in accordance with Canadian GAAP.

2. ACCOUNTING POLICIES

The accounting policies we follow are described in Note 2 of the Unaudited Condensed Consolidated Financial Statements for the three months ended March 31, 2011.

Future Changes in Accounting Policies

As part of our transition to IFRS, we will adopt 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.

- IFRS 9 *Financial Instruments* – in November 2009, the International Accounting Standards Board (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, 2013. 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 is required to be adopted for periods beginning January 1, 2013. We are evaluating the impact that this standard may have on our results of operations and 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. We are evaluating the impact that this standard may have on our results of operations and financial position.
- 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 a company 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 are evaluating the impact that this standard may have on our financial statement disclosure.

- 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 are evaluating the impact that this standard may have 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 split items of other comprehensive income (OCI) between those that are reclassified to income and those that do not. The standard is required to be adopted for periods beginning on or after July 1, 2012. We are evaluating the impact that this standard may have on our results of operations and financial position.
- 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. We are evaluating the impact that this standard may have on our results of operations and financial position.

3. ACCOUNTS RECEIVABLE

	September 30 2011	December 31 2010	January 1 2010
Trade			
Energy Marketing	1,119	929	1,410
Oil and Gas	662	822	823
Other	5	2	44
	<u>1,786</u>	<u>1,753</u>	<u>2,277</u>
Non-Trade	125	80	99
	<u>1,911</u>	<u>1,833</u>	<u>2,376</u>
Allowance for Doubtful Receivables	(41)	(44)	(54)
Total ¹	<u><u>1,870</u></u>	<u><u>1,789</u></u>	<u><u>2,322</u></u>

¹ At December 31, 2010, accounts receivable related to our chemicals operations have been included with assets held for sale (see Note 14).

Receivables are generally on 30-day terms and were current as of September 30, 2011, December 31, 2010 and January 1, 2010.

4. INVENTORIES AND SUPPLIES

	September 30 2011	December 31 2010	January 1 2010
Finished Products			
Energy Marketing	271	452	548
Oil and Gas	18	35	25
Other	–	–	12
	<u>289</u>	<u>487</u>	<u>585</u>
Work in Process	6	5	7
Field Supplies	52	58	88
Total ¹	<u><u>347</u></u>	<u><u>550</u></u>	<u><u>680</u></u>

¹ At December 31, 2010, inventories and supplies related to our chemicals operations have been included with assets held for sale (see Note 14).

5. PROPERTY, PLANT AND EQUIPMENT (PP&E)

(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	(326)	—	(2)	—	(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	2,992	1,748	18,885	757	24,382
Additions	787	461	460	49	1,757
Disposals/Derecognitions	(48)	—	(52)	(12)	(112)
Transfers	(296)	292	4	—	—
Exploration Expense	(277)	—	(1)	—	(278)
Other	81	21	142	—	244
Effect of Changes in Exchange Rate	43	121	520	10	694
As at September 30, 2011	3,282	2,643	19,958	804	26,687
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	37	—	882	54	973
Disposals/Derecognitions	(11)	—	(51)	(8)	(70)
Impairments	—	—	141	—	141
Other	—	—	(17)	—	(17)
Effect of Changes in Exchange Rate	10	—	391	5	406
As at September 30, 2011	367	—	10,400	469	11,236
Net Book Value					
As at January 1, 2010	2,033	1,034	10,695	907	14,669
As at December 31, 2010	2,661	1,748	9,831	339	14,579
As at September 30, 2011	2,915	2,643	9,558	335	15,451

Exploration and evaluation assets mainly comprise of unproved properties and capitalized exploration drilling costs. Assets under construction include our Usan development, offshore Nigeria.

(b) Impairment

Our DD&A expense for the third quarter of 2011 includes non-cash impairment charges of \$141 million for our Canadian coalbed methane and conventional gas assets included within our Conventional North America segment. Lower estimated future natural gas prices in the quarter resulted in impairment of the properties.

Our DD&A expense for the third quarter of 2010 includes non-cash impairment charges of \$59 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 reduced the properties' estimated fair value less costs to sell.

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 market-based future prices, an after-tax discount rate of 9% and management's estimate of future production, capital and operating expenditures.

6. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	September 30	December 31	January 1
	2011	2010	2010
Energy Marketing Payables	1,181	1,016	1,366
Accrued Payables	825	676	619
Income Taxes Payable	468	345	179
Trade Payables	201	164	210
Stock-Based Compensation	39	111	173
Other	163	147	134
Total ¹	2,877	2,459	2,681

¹ At December 31, 2010, accounts payable and accrued liabilities related to our chemicals operations have been included with liabilities held for sale (see Note 14).

7. LONG-TERM DEBT

	September 30	December 31	January 1
	2011	2010	2010
Term Credit Facilities, due 2016 (a)	–	–	1,570
Notes, due 2013 (US\$500 million) (b)	–	497	523
Notes, due 2015 (US\$126 million) (c)	131	249	262
Notes, due 2017 (US\$62 million) (c)	64	249	262
Notes, due 2019 (US\$300 million)	312	298	314
Notes, due 2028 (US\$200 million)	208	199	209
Notes, due 2032 (US\$500 million)	519	497	523
Notes, due 2035 (US\$790 million)	821	786	827
Notes, due 2037 (US\$1,250 million)	1,299	1,243	1,308
Notes, due 2039 (US\$700 million)	727	696	733
Subordinated Debentures, due 2043 (US\$460 million)	478	457	481
	4,559	5,171	7,012
Unamortized debt issue costs	(80)	(81)	(88)
	4,479	5,090	6,924
Canexus debt	–	–	335
Total	4,479	5,090	7,259

(a) Term credit facilities

We have unsecured term credit facilities of \$3.2 billion (US\$3.1 billion) available until 2016, none of which were drawn at either September 30, 2011 or December 31, 2010. Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime rate loans, US-dollar base rate loans or British pound call-rate loans. Interest is payable at floating rates. During the nine months ended September 30, 2011, we did not incur interest expense on our term credit facilities. At September 30, 2011, \$271 million (US\$261 million) of these facilities were utilized to support outstanding letters of credit (December 31, 2010 – \$322 million (US\$324 million)).

(b) Redemption of Notes, due 2013

In the second quarter 2011, we redeemed and cancelled US\$500 million of principal from bonds due in 2013. We paid \$525 million for the redemption. We recorded a \$52 million loss as the difference between carrying value and the redemption price.

(c) Repurchase for Cancellation of Certain 2015 and 2017 Notes

In the first quarter 2011, we repurchased and cancelled US\$124 million and US\$188 million of principal from the 2015 and 2017 bonds, respectively. We paid \$346 million for the repurchase and recorded a \$39 million loss as the difference between carrying value and the redemption price.

(d) Short-term borrowings

Nexen has uncommitted, unsecured credit facilities of approximately \$466 million (US\$449 million), none of which were drawn at either September 30, 2011 or December 31, 2010. We utilized \$8 million (US\$8 million) of these facilities to support outstanding letters of credit at September 30, 2011 (December 31, 2010—\$112 million (US\$112 million)). Interest is payable at floating rates.

8. FINANCE EXPENSE

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
Long-Term Debt Interest Expense	73	89	231	269
Accretion Expense related to Asset Retirement Obligations (Note 9)	12	12	35	31
Other Interest Expense	7	9	17	30
Total	92	110	283	330
Less: Capitalized at 6.7% (2010 – 6.3%)	(33)	(23)	(90)	(57)
Total ¹	59	87	193	273

¹ Excludes interest expense related to our chemical operations (see Note 14).

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.

9. ASSET RETIREMENT OBLIGATIONS (ARO)

Changes in the carrying amount of our ARO provisions are as follows:

	Nine Months Ended September 30	Twelve Months Ended December 31
	2011	2010
ARO, Beginning of Period	1,571	1,432
Obligations Incurred with Development Activities	25	81
Changes in Estimates	156	332
Obligations Related to Dispositions	(2)	(224)
Obligations Settled	(58)	(43)
Accretion	35	47
Effects of Changes in Foreign Exchange Rate	51	(54)
ARO, End of Period	1,778	1,571
Of which:		
Due within Twelve Months ¹	53	55
Due after Twelve Months	1,725	1,516

¹ Included in accounts payable and accrued liabilities.

ARO represents the present value of estimated remediation and reclamation costs associated with our PP&E. We have discounted the estimated asset retirement obligation using a weighted-average risk-free rate of 3.1% (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 \$368 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.

10. RELATED PARTY DISCLOSURES

Major subsidiaries and joint ventures

The Unaudited Condensed Consolidated Financial Statements include the financial statements of Nexen Inc. and our subsidiaries as at September 30, 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 nine months ended September 30, 2011 and 2010.

Major Subsidiaries	Country of Incorporation	Principal Activities	Ownership
Nexen Petroleum UK Limited	United Kingdom	Oil & Gas	100%
Nexen Ettrick UK Limited	United Kingdom	Oil & Gas	100%
Nexen Petroleum Nigeria Limited	Nigeria	Oil & Gas	100%
Nexen Petroleum Offshore USA Inc	United States	Oil & Gas	100%
Canadian Nexen Petroleum Yemen	Yemen	Oil & Gas	100%
Canadian Nexen Petroleum East Al Hajr	Canada	Oil & Gas	100%
Nexen Petroleum Colombia Limited	Jersey	Oil & Gas	100%
Nexen Med Hat-Hatton Partnership	Canada	Oil & Gas	100%
Nexen Crossfield Partnership	Canada	Oil & Gas	100%
Nexen Marketing	Canada	Marketing	100%
Nexen Energy Marketing Europe	United Kingdom	Marketing	100%
Nexen Energy Marketing USA Inc	United States	Marketing	100%
Joint Venture			
Syncrude	Canada	Oil & Gas	7.23%

11. EQUITY

(a) Common Shares

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 September 30, 2011, there were 527,406,242 common shares outstanding (December 31, 2010 – 525,706,403 shares; January 1, 2010 – 522,915,843 shares). There were no preferred shares issued and outstanding as at September 30, 2011 (December 31, 2010 – nil; January 1, 2010 – nil).

(b) Dividends

Dividends paid per common share for the three months ended September 30, 2011 were \$0.05 per common share (three months ended September 30, 2010 – \$0.05). Dividends per common share for the nine months ended September 30, 2011 were \$0.15 per common share (nine months ended September 30, 2010 – \$0.15). Dividends paid to holders of common shares have been designated as “eligible dividends” for Canadian tax purposes. On October 26, 2011, the Board of Directors declared a quarterly dividend of \$0.05 per common share, payable January 1, 2012 to the shareholders of record on December 9, 2011.

12. COMMITMENTS, CONTINGENCIES AND GUARANTEES

As described in Note 15 to the 2010 Audited Consolidated Financial Statements, there are a number of lawsuits and claims pending, the ultimate results of which cannot be ascertained at this time. We record costs as they are incurred or become determinable. We believe that payments, if any, related to existing indemnities, would not have a material adverse effect on our liquidity, financial condition or results of operations.

We assume various contractual obligations and commitments in the normal course of our operations. Our operating leases, transportation and storage commitments, and drilling rig commitments as at September 30, 2011 have not materially changed from the information previously disclosed in Note 12 to the Unaudited Condensed Consolidated Financial Statements for the three and six months ended June 30, 2011 and Note 15 to the 2010 Audited Consolidated Financial Statements.

13. MARKETING AND OTHER INCOME

	Three Months		Nine Months	
	Ended September 30		Ended September 30	
	2011	2010	2011	2010
Marketing Revenue, Net	72	84	174	280
Insurance Proceeds	—	—	26	—
Change in Fair Value of Crude Oil Put Options	13	(5)	6	(19)
Foreign Exchange Gains (Losses)	30	(4)	14	(6)
Other	10	42	46	49
Total	125	117	266	304

14. DISPOSITIONS

(a) Discontinued Operations

In February 2011, we completed the sale of our 62.7% investment in Canexus Limited Partnership, 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.

	Three Months Ended September 30		
	2010		
	Canada	Chemicals	Total
Revenues and Other Income			
Net Sales	13	118	131
Other	—	13	13
Gain on Disposition	828	—	828
	<u>841</u>	<u>131</u>	<u>972</u>
Expenses			
Operating	5	80	85
Depreciation, Depletion, Amortization and Impairment	—	6	6
Transportation and Other	—	13	13
General and Administrative	1	8	9
Finance	—	5	5
	<u>6</u>	<u>112</u>	<u>118</u>
Income before Provision for Income Taxes	<u>835</u>	<u>19</u>	<u>854</u>
Less: Provision for Deferred Income Taxes	210	4	214
Income before Non-Controlling Interest	625	15	640
Less: Non-Controlling Interest	—	5	5
Net Income from Discontinued Operations, Net of Tax	<u>625</u>	<u>10</u>	<u>635</u>
Earnings Per Common Share			
Basic			1.21
Diluted			<u>1.17</u>

	Nine Months Ended September 30			
	2011	2010		
	Chemicals	Canada	Chemicals	Total
Revenues and Other Income				
Net Sales	42	138	336	474
Other	(1)	–	13	13
Gain on Disposition	348	828	–	828
	389	966	349	1,315
Expenses				
Operating	25	50	228	278
Depreciation, Depletion, Amortization and Impairment	4	20	20	40
Transportation and Other	2	2	41	43
General and Administrative	2	10	26	36
Finance	2	3	12	15
	35	85	327	412
Income before Provision for Income Taxes	354	881	22	903
Less: Provision for Deferred Income Taxes	51	220	5	225
Income before Non-Controlling Interest	303	661	17	678
Less: Non-Controlling Interest	1	–	6	6
Net Income from Discontinued Operations, Net of Tax	302	661	11	672
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 September 30, 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	729¹	654
Accounts Payable and Accrued Liabilities	59	64
Accrued Interest Payable	3	–
Long-Term Debt	414	335
Deferred Income Tax Liabilities	15	11
Asset Retirement Obligations	73	74
Other Long-Term Liabilities	18	16
Liabilities	582¹	500
Equity – Canexus Non-Controlling Interest	48	33

¹ Included in assets and liabilities held for sale at December 31, 2010.

(b) Asset Dispositions

Natural Gas Energy Marketing Disposition

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 our 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.

15. CASH FLOWS

(a) Charges and credits to income not involving cash

	Three Months		Nine Months	
	Ended September 30	Ended September 30	Ended September 30	Ended September 30
	2011	2010	2011	2010
Depreciation, Depletion, Amortization and Impairment	409	435	1,114	1,136
Finance	59	87	193	273
Stock-Based Compensation	(65)	(2)	(67)	(61)
Loss on Debt Redemption and Repurchase	–	–	91	–
Net (Gain) Loss on Dispositions	–	259	(12)	179
Non-cash Items Included in Discontinued Operations	–	(637)	(290)	(577)
Provision for Income Taxes	308	76	1,189	489
Foreign Exchange	(31)	21	(14)	22
Other	(18)	6	(10)	86
Total	662	245	2,194	1,547

(b) Changes in non-cash working capital

	Three Months		Nine Months	
	Ended September 30	Ended September 30	Ended September 30	Ended September 30
	2011	2010	2011	2010
Accounts Receivable	61	240	(73)	6
Inventories and Supplies	(3)	(88)	181	(12)
Other Current Assets	(4)	(32)	(13)	46
Accounts Payable and Accrued Liabilities	154	91	381	173
Total	208	211	476	213
Relating to:				
Operating Activities	139	316	292	243
Investing Activities	69	(105)	184	(30)
Total	208	211	476	213

16. 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 ramped up production at Long Lake. We report our segments to align with our key growth strategies, specifically, Conventional Oil and Gas, Oil Sands and Unconventional Gas. Prior period results have been revised to reflect the presentation changes made in the current period.

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 (Yemen, offshore West Africa and Colombia).

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.

Unconventional 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. Canexus manufactures, markets and distributes industrial chemicals, principally sodium chlorate, chlorine, muriatic acid and caustic soda. The results of our chemicals business have been presented as discontinued operations.

The accounting policies of our operating segments are the same as those described in Note 2 of the Unaudited Condensed Consolidated Financial Statements for the three months ended March 31, 2011. 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 three months ended September 30, 2011

	Conventional			Oil Sands		Corporate and	Total
	United Kingdom	North America	Other Countries ¹	In Situ	Syncrude	Other	
Net Sales	756	112	185	146	185	15	1,399
Marketing and Other Income	—	4	5	—	2	114	125
	756	116	190	146	187	129	1,524
Less: Expenses							
Operating	106	34	39	97	73	7	356
Depreciation, Depletion, Amortization and Impairment	124	210	18	30	16	11	409
Transportation and Other	5	10	7	49	6	33	110
General and Administrative	(7)	3	2	(1)	1	25	23
Exploration	15	17	27 ²	—	—	—	59
Finance	6	5	—	1	1	46	59
Income (Loss) from Continuing Operations before Income Taxes	507	(163)	97	(30)	90	7	508
Less: Provision for (Recovery of) Income Taxes	301	(39)	26	(8)	23	5	308
Net Income (Loss)	206	(124)	71	(22)	67	2	200
Capital Expenditures	190	243	161	90	34	11	729

¹ Includes results of conventional crude oil and natural gas operations in Yemen and Colombia.

² Includes exploration activities primarily in Nigeria, Norway, Colombia and Poland.

Segmented net income for the three months ended September 30, 2010

	Conventional			Oil Sands		Corporate and	Total
	United Kingdom	North America	Other Countries ¹	In Situ	Syncrude	Other	
Net Sales	753	129	192	109	130	8	1,321
Marketing and Other Income	5	—	4	—	2	106	117
	758	129	196	109	132	114	1,438
Less: Expenses							
Operating	84	42	39	93	68	8	334
Depreciation, Depletion, Amortization and Impairment	197	152	32	28	12	14	435
Transportation and Other	1	5	3	51	5	65	130
General and Administrative	3	22	5	6	1	78	115
Exploration	11	25	20 ²	—	—	—	56
Finance	4	4	1	1	1	76	87
Net Loss from Dispositions	—	—	—	—	—	259 ³	259
Income (Loss) from Continuing Operations before Income Taxes	458	(121)	96	(70)	45	(386)	22
Less: Provision for (Recovery of) Income Taxes	229	(38)	24	(17)	11	(133)	76
Income (Loss) from Continuing Operations	229	(83)	72	(53)	34	(253)	(54)
Add: Net Income from Discontinued Operations (Note 14)	—	599	—	—	—	36	635
Net Income (Loss)	229	516	72	(53)	34	(217)	581
Capital Expenditures	194	165	150	47	34	39	629

¹ Includes results of conventional crude oil and natural gas operations in Yemen and Colombia.

² Includes exploration activities primarily in Yemen, Nigeria, Norway and Colombia.

³ Loss on disposition of Natural Gas Energy Marketing Business.

Segmented net income for the nine months ended September 30, 2011

	Conventional			Oil Sands		Corporate and Other	Total
	United Kingdom	North America	Other Countries ¹	In Situ	Syncrude		
Net Sales	2,482	379	599	449	555	40	4,504
Marketing and Other Income	17	36	12	—	3	198	266
	2,499	415	611	449	558	238	4,770
Less: Expenses							
Operating	265	110	109	331	223	22	1,060
Depreciation, Depletion, Amortization and Impairment	439	431	66	95	46	37	1,114
Transportation and Other	5	25	23	118	18	100	289
General and Administrative	(17)	55	25	12	1	128	204
Exploration	32	117	127 ²	2	—	—	278
Finance	16	13	1	2	4	157	193
Net Loss on Debt Redemption	—	—	—	—	—	91	91
Income (Loss) from Continuing Operations before Income Taxes	1,759	(336)	260	(111)	266	(297)	1,541
Less: Provision for (Recovery of) Income Taxes	1,313	(85)	30	(28)	67	(108)	1,189
Income (Loss) from Continuing Operations	446	(251)	230	(83)	199	(189)	352
Add: Net Income from Discontinued Operations (Note 14)	—	—	—	—	—	302	302
Net Income (Loss)	446	(251)	230	(83)	199	113	654
Capital Expenditures	368	485	478	310	80	37	1,758

¹ Includes results of conventional crude oil and natural gas operations in Yemen and Colombia.

² Includes exploration activities primarily in Nigeria, Norway, Colombia and Poland.

Segmented net income for the nine months ended September 30, 2010

	Conventional			Oil Sands		Corporate and Other	Total
	United Kingdom	North America	Other Countries ¹	In Situ	Syncrude		
Net Sales	2,243	423	560	302	416	29	3,973
Marketing and Other Income	14	1	12	—	4	273	304
	<u>2,257</u>	<u>424</u>	<u>572</u>	<u>302</u>	<u>420</u>	<u>302</u>	<u>4,277</u>
Less: Expenses							
Operating	238	124	119	273	200	24	978
Depreciation, Depletion, Amortization and Impairment	550	342	94	68	39	43	1,136
Transportation and Other	5	15	9	134	16	285	464
General and Administrative	16	52	13	10	1	172	264
Exploration	42	66	90 ²	1	—	—	199
Finance	12	12	1	2	3	243	273
Net (Gain) Loss from Dispositions	—	—	—	(80) ³	—	259 ⁴	179
Income (Loss) from Continuing Operations before Income Taxes	<u>1,394</u>	<u>(187)</u>	<u>246</u>	<u>(106)</u>	<u>161</u>	<u>(724)</u>	<u>784</u>
Less: Provision for (Recovery of) Income Taxes	697	(55)	45	(26)	40	(212)	489
Income (Loss) from Continuing Operations	<u>697</u>	<u>(132)</u>	<u>201</u>	<u>(80)</u>	<u>121</u>	<u>(512)</u>	<u>295</u>
Add: Net Income from Discontinued Operations (Note 14)	—	635	—	—	—	37	672
Net Income (Loss)	<u>697</u>	<u>503</u>	<u>201</u>	<u>(80)</u>	<u>121</u>	<u>(475)</u>	<u>967</u>
Capital Expenditures	<u>471</u>	<u>692</u>	<u>463</u>	<u>156</u>	<u>83</u>	<u>174</u>	<u>2,039</u>

¹ Includes results of conventional crude oil and natural gas operations in Yemen and Colombia.

² Includes exploration activities primarily in Yemen, Nigeria, Norway and Colombia.

³ Gain on disposition of non-core lands in the Athabasca region.

⁴ Loss on disposition of Natural Gas Energy Marketing Business.

Segmented assets as at September 30, 2011

	Conventional			Oil Sands		Corporate and Other	Total
	United Kingdom	North America	Other Countries	In Situ	Syncrude		
Total Assets	4,657	3,328	2,093	6,024	1,278	2,349 ¹	19,729
Property, Plant and Equipment							
Cost	7,094	7,017	4,289	6,064	1,597	626	26,687
Less: Accumulated DD&A	3,639	4,108	2,547	174	403	365	11,236
Net Book Value	3,455	2,909 ²	1,742 ³	5,890 ⁴	1,194	261	15,451
Goodwill	290	–	–	–	–	7	297

¹ Includes cash of \$474 million, and Energy Marketing accounts receivable and inventory of \$1,390 million.

² Includes capitalized costs of \$1,198 million associated with our Canadian shale gas operations.

³ Includes \$1,653 million related to our Usan development, offshore Nigeria.

⁴ Includes net book value of \$5,004 million for Long Lake Phase 1 and \$886 million for future phases of our in situ oil sands projects.

Segmented assets as at December 31, 2010

	Conventional			Oil Sands		Corporate and Other	Total
	United Kingdom	North America	Other Countries	In Situ	Syncrude		
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
Goodwill	277	–	–	–	–	9	286

¹ Includes cash of \$817 million, Energy Marketing accounts receivable and inventory of \$1,381 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

	Conventional			Oil Sands		Corporate and Other	Total
	United Kingdom	North America	Other Countries	In Situ	Syncrude		
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
Goodwill	292	–	–	–	–	38	330

¹ Includes cash of \$1,016 million, Energy Marketing accounts receivable and inventory of \$1,958 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.

17. 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) for all periods after January 1, 2011 including comparative historical information. As we are also publicly listed in the United States, we were required to include a reconciliation of our financial results between Canadian GAAP and US GAAP. The reconciliation to US GAAP is no longer required.

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 of the Unaudited Condensed Consolidated Financial Statements for the three months ended March 31, 2011. The consolidated financial statements for the year ended December 31, 2011 will be 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 Unaudited Condensed 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, which is included in accumulated other comprehensive income, 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 had vested or 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 Unaudited Condensed 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	September 30 2010	December 31 2010
Shareholders' Equity under Canadian GAAP		7,646	8,606	8,791
Differences increasing (decreasing) reported shareholders' equity:				
Borrowing Costs	(i)	(841)	(796)	(778)
Asset Retirement Obligations	(ii)	(228)	(237)	(241)
Employee Benefits	(iii)	(104)	(104)	(150)
Stock-Based Compensation	(iv)	(96)	(72)	(92)
Property, Plant & Equipment	(v)	(124)	(47)	(90)
Foreign Exchange	(vi)	(11)	(6)	–
Long-term Debt	(vii)	(9)	(27)	(28)
Income Taxes	(viii)	554	416	429
Other		–	(9)	(27)
Shareholders' Equity under IFRS		6,787	7,724	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 were required on transition to IFRS.

Major Maintenance

Under 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.

(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 self-sustaining 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	Three Months Ended September 30 2010	Nine Months Ended September 30 2010	Twelve Months Ended December 31 2010
Net Income under Canadian GAAP		537	977	1,197
Differences increasing (decreasing) reported net income:				
Borrowing Costs	(i)	18	45	63
Asset Retirement Obligations	(ii)	15	(9)	(13)
Stock-Based Compensation	(iii)	9	23	3
Property, Plant & Equipment	(iv)	65	77	34
Long-term Debt	(v)	(1)	(18)	(19)
Income Taxes	(vi)	(57)	(138)	(136)
Other		(5)	10	(2)
Total Differences in Net Income		44	(10)	(70)
Net Income under IFRS		581	967	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 \$29 million and \$88 million for the three and nine months ended September 30, 2010, respectively, and 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 \$28 million and \$50 million for the three and nine months ended September 30, 2010, respectively, and \$19 million for the twelve months ended December 31, 2010.

Reconciliation of Comprehensive Income

(Cdn\$ millions)	Note	Three Months Ended September 30 2010	Nine Months Ended September 30 2010	Twelve Months Ended December 31 2010
Comprehensive Income under Canadian GAAP		530	971	1,168
Differences increasing (decreasing) reported comprehensive income, net of income taxes:				
Differences in net income		44	(10)	(70)
Foreign Currency Translation	(i)	(2)	(8)	(8)
Employee Benefits	(ii)	—	—	(35)
Comprehensive Income under IFRS		572	953	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 of the Unaudited Condensed Consolidated Financial Statements for the three months ended March 31, 2011, 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.