For three months ended June 30, 2011

Q2

nexen

Nexen Announces Second Quarter Results & Return to Drilling in the Gulf of Mexico

(Cdn$ millions,except as indicated)	Three Months Ended June 30 2011	Three Months Ended March 31 2011	Three Months Ended June 30 2010[4]	Six Months Ended June 30 2011	Six Months Ended June 30 2010[4]
Production Before Royalties (mboe/d)	204	232	248	218	250
Production After Royalties (mboe/d)	180	207	218	194	220
Cash flow from operations [1]	598	669	549	1,267	1,098
Per common share ($/share)	1.13	1.27	1.05	2.40	2.10
Net income	252	202	245	454	386
Per common share ($/share)	0.48	0.38	0.47	0.86	0.74
Capital investment [2]	530	499	840	1,029	1,410
Net debt [3]	2,838	3,350	5,492	2,838	5,492
Common Shares Outstanding (millions)	527.0	526.7	524.6	527.0	524.6

[1] Cash flow from operations is defined as cash flow from operating activities before changes in non-cash working capital and other.
[2] Includes oil and gas development, exploration, geological and geophysical costs, and expenditures for other PP&E.
[3] Defined as long-term debt and short-term borrowings less cash and cash equivalents.
[4] Restated for adoption of International Financial Reporting Standards (IFRS).

Nexen Inc's second quarter 2011 operating and financial results were led by strong oil prices, high netbacks, and a portfolio weighted towards unhedged, Brent-priced oil. This portfolio weighting contributed to strong cash flow during the quarter. Also contributing to cash flow was our Long Lake operation, which generated its first positive quarterly cash flow of $6 million as compared to a loss of $19 million in the first quarter. Net income increased from the prior quarter. The first quarter included the impact of the UK tax rate change which decreased net income by $336 million. This was partially offset by a $299 million after-tax gain on the sale of Canexus.

Production of 204,000 boe/d reflects maintenance activities at our Buzzard platform in the UK North Sea which are expected to be completed in August. Yemen production reflects natural field declines following the completion of development drilling activities as we near the end of the primary contract term in December of this year, and the two-day shutdown during a labour strike. Unscheduled maintenance on the LC Finer and the Vacuum Distillation Unit impacted Syncrude production. The repairs have been completed and production subsequently returned to full rates.

At Long Lake, bitumen production averaged 27,900 bbls/d gross (18,100 bbls/d net to Nexen), up 2,300 bbls/d from the first quarter. Production is increasing as a result of higher steam injection following the hot lime softener (HLS) scheduled maintenance, well optimizations and the continuing ramp-up of the new pad 11 wells. In June, we processed 45,000 bbls/d of proprietary and third-party bitumen volumes (28,900 bbls/d and 16,100 bbls/day, respectively) achieving approximately 65% of upgrader capacity. We continue to advance various initiatives for resource development to fill the upgrader and we expect production from Long Lake to continue to increase into the mid-30,000 bbls/d range by year-end.

Given the impact of operational events at Buzzard and Long Lake in the first half of the year, our annual production before royalties is now expected to be 210,000 to 230,000 boe/d.

During the quarter, we achieved several milestones in other areas of our business. Our Usan project remains on track, with the floating production and storage offloading vessel (FPSO) enroute to site. The project is expected to achieve first oil in the first half of 2012. We also continued our industry-leading execution in our shale gas business with the drilling of a nine-well pad. We began fracing and completion activities during the quarter, and first production from this pad is expected in the fourth quarter. We also commenced drilling an 18-well pad. Lastly, our exploration efforts advanced in the Gulf of Mexico. We received a drilling permit for our Kakuna exploration well and commenced drilling late in June. Our partner, Shell, received a drilling permit for an appraisal well to follow up our Appomattox discovery.

The Board of Directors has declared the regular quarterly dividend of $0.05 per common share payable October 1, 2011, to shareholders of record on September 9, 2011.

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2011

The following should be read in conjunction with the Unaudited Condensed Consolidated Financial Statements for the three and six months ended June 30, 2011. The date of this discussion is July 13, 2011.

Unless otherwise noted, tabular amounts are in millions of Canadian dollars. The discussion and analysis of our oil and gas activities with respect to oil and gas volumes, reserves and related performance measures is presented on a working-interest, before-royalties basis. We measure our performance in this manner consistent with other Canadian oil and gas companies. Where appropriate, information on a net, after-royalties basis is also presented.

Investors should read the "Forward-Looking Statements" on page 24.

EXECUTIVE SUMMARY

	Three Months Ended			Six Months Ended	
(Cdn$ millions, except as indicated)	June 30 **2011**	March 31 **2011**	June 30 **2010**	June 30 **2011**	June 30 **2010**
Production before Royalties (mboe/d) [1]	204	232	248	218	250
Production after Royalties (mboe/d)	180	207	218	194	220
Cash Flow from Operations [2, 3]	598	669	549	1,267	1,098
Net Income [2]	252	202	245	454	386
Earnings per Common Share, Basic [2] ($/share)	0.48	0.38	0.47	0.86	0.74
Earnings per Common Share, Diluted [2] ($/share)	0.45	0.38	0.43	0.84	0.69
Net Debt [4]	2,838	3,350	5,492	2,838	5,492

[1] Production before royalties reflects our working interest before royalties. We have presented our working interest before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies. We report bitumen as production at Long Lake.
[2] Includes results of discontinued operations (see Note 14 of our Unaudited Condensed Consolidated Financial Statements).
[3] Cash flow from operations is a non-GAAP measure and is reconciled to the nearest GAAP measure on page 23.
[4] Net debt is a non-GAAP measure and is reconciled to the nearest GAAP measure on page 23.

Production averaged 204,000 boe/d for the quarter, down 12% from the previous quarter and 18% from the same period last year. The decrease is due to lower production at Buzzard, which was impacted by unscheduled maintenance to repair the cooling system and interruptions to a third–party operated natural gas export pipeline. While the repair work proceeded on schedule, production was lower than expected due to the gas export restrictions. Production at Buzzard is expected to be back to full rates in August. Production in the second quarter of 2010 included volumes from our heavy oil assets, which were sold during the third quarter of 2010.

Cash flow from operations increased 9% from the same period last year as the impact of higher prices was only partially offset by lower production. With approximately 80% of our crude oil sales based on Brent prices, we benefit from stronger Brent pricing. Brent averaged US$117.36/bbl, 12% higher than the previous quarter and a US$14.80/bbl premium over WTI in the current quarter. Also contributing to cash flow was our Long Lake operation, which generated its first quarterly positive cash flow of $6 million as compared to a loss of $19 million in the first quarter.

Investment during the quarter included progressing Usan towards first oil in the first half of 2012, and exploration and development activities in the North Sea. At Horn River in northeast BC, we began fracing and completing the wells during the quarter on the nine-well pad, and first production from this pad is expected in the fourth quarter. At Long Lake, we commenced drilling two additional well pads and advancing engineering work on various other initiatives to support increased production to fill the upgrader. We received approval for the Appomattox exploration plan and drilling of the first appraisal well, and drilling began late in the quarter on the Kakuna exploration well in the deepwater Gulf of Mexico.

During the quarter, we redeemed US$500 million bonds due in 2013. Combined with US$312 million in debt repurchased and cancelled in the first quarter, approximately $800 million of long-term debt has been repurchased and cancelled this year. We incurred a loss of $91 million on the debt repurchases. Approximately 90% of the loss represents the difference between market value and carrying value of the bonds. We also realized $229 million of foreign exchange gains on this US-denominated debt since it was issued as the Canadian dollar has strengthened during that period. This gain was included in retained earnings on transition to IFRS.

Our asset disposition program of the last 18 months successfully captured value and increased our financial capacity, while narrowing our focus on our core growth strategies. The program contributed to a $3 billion decrease in net debt from $5.9 billion to $2.8 billion (52%) over the past two years. Net debt is expected to rise in the second half of the year due to the timing of our capital spending and working capital changes. Capital investment is expected to increase in the latter half of the year with the increased drilling in the Gulf of Mexico, the North Sea and Canadian shale gas and oil sands. Nexen retains access to liquidity of approximately $4.3 billion. This consists of approximately $1.3 billion of cash on hand and $3.0 billion of committed undrawn credit facilities.

STRATEGY PROGRESS

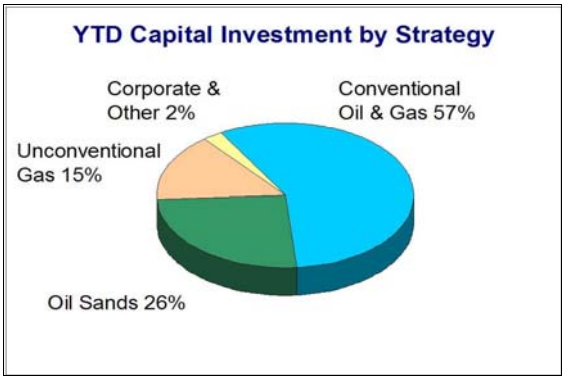
Our strategy and capital programs are focused on growing value for our shareholders responsibly. To maximize value, we invest in:

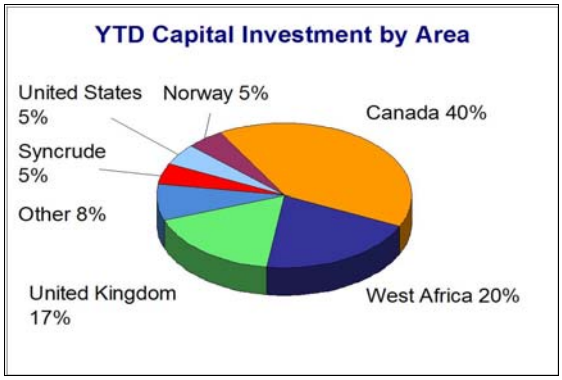
- core assets for short-term production and free cash flow to fund capital programs and repay debt;
- development projects that convert our discoveries into new production and cash flow in the medium term; and
- appraisal, exploration and new growth projects for longer-term growth.

We invest in key focus areas including Athabasca oil sands, unconventional gas and conventional offshore opportunities in the North Sea, deepwater Gulf of Mexico, and West Africa.

Details of our capital programs are set out below:

	Three Months Ended June 30 **2011**	Six Months Ended June 30 **2011**
Conventional Oil & Gas		
North Sea	124	226
West Africa	114	214
United States	33	49
Yemen	9	19
Other	47	74
	327	582
Oil Sands		
Long Lake, Kinosis and Other Insitu	91	220
Syncrude	27	46
	118	266
Unconventional Gas	71	155
Total Oil and Gas	516	1,003
Corporate and Other	14	26
Total Capital	530	1,029





Nexen has numerous opportunities available with several development and appraisal projects underway, and a large resource base to support 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 second quarter, we made progress on our key milestones in moving these projects into production and cash flow.

Conventional Oil & Gas

Offshore West Africa
Development of the Usan field remains on track for first oil in the first half of 2012. Fabrication of the FPSO vessel in Korea is now complete. The FPSO is under tow and expected to arrive on location offshore Nigeria this summer for hook-up to the wells and commissioning. At full capacity, the project is capable of producing 180,000 boe/d (36,000 boe/d net to us). We have a 20% interest in Usan and the project joint venture partners are Total E&P Nigeria Limited (the operator), ExxonMobil and Chevron.

Gulf of Mexico
Shell, the operator of the Appomattox discovery, received approval of the supplemental Exploration Plan for a multi-well exploration and appraisal drilling program on the Appomattox discovery. They received a drilling permit for the first appraisal well and expect to spud it in the third quarter. This is the first of three wells planned to appraise Appomattox and adjacent structures. We have a 20% working interest in Appomattox and a 25% working interest in the nearby Vicksburg discovery.

We received approval to drill the Kakuna exploration well which spud in late June in the vicinity of the producing Tahiti field and various other discoveries. Following the Kakuna well, we expect to drill the Angel Fire prospect once the drilling permit is approved. Farm-out negotiations continue on exploration prospects in the Gulf of Mexico.

UK North Sea
The approval process for the Golden Eagle development continues to progress well. Development of the field is expected to commence once all partners complete their approval processes and regulatory approvals are in place, which we expect to occur later this summer.

Regulatory approval was received for the Blackbird tieback to the Ettrick facility. We also continue to progress the tie-in of the Telford TAC well to the Scott platform. Blackbird and Telford are both on track to deliver increased production late this year. These projects, when combined with the Rochelle tieback to the Scott platform, are expected to contribute approximately 10,000 to 20,000 boe/d net to us by the end of 2012. Over the next 12 months, we plan to drill an appraisal of the Polecat discovery and a number of exploration prospects, including the North Uist well west of the Shetland Islands.

Oil Sands

Long Lake
Our primary focus is on increasing our bitumen production to fill the upgrader. This provides us with an attractive return on capital as the predominantly fixed cost nature of the operation means that each incremental barrel of production contributes significantly to cash flow and profitability. With the upgrader operating at an average of 50% capacity during the quarter, we generated positive cash flow. At full capacity and US$90 WTI, the project is expected to generate about $800 million of cash flow annually.

Our strategy for filling the upgrader includes:

- growth in production from the initial 10 pads;
- ramp-up of pad 11;
- start-up of pads 12 and 13 that are currently being drilled;
- drilling of pads 14 and 15 which we are targeting to commence drilling in 2012;
- identifying future drilling on the Long Lake and Kinosis leases; and
- processing of third party sourced bitumen in the interim to enhance returns from this facility.

We believe the continued drilling of resource on Long Lake and the advancement of Kinosis drilling is the most economic and expedient strategy to grow and sustain our proprietary bitumen volumes to fill the upgrader.

Initially, we expected to fill the upgrader from the first 11 pads that are now on-stream, however, we underestimated the impact lean zones and shales would have on production rates and steam-oil ratio (SOR). We better understand the correlation between reservoir characteristics and production and SOR, based on the range of well performance we experienced in the initial wells. This understanding allows us to target the best quality resource for development

that is analogous to the wells in our initial set that are exhibiting good performance. It also confirms that our oil sands lands, including undeveloped areas on the Long Lake lease, contain attractive resource.

We expect production from pads 1 to 11 to continue to increase over time from additional steam, heating through the lean zones, the ramp-up of wells as they mature, and well work-over activities. Production from pad 11 is currently approximately 1,700 bbls/d and is expected to contribute 4,000 to 8,000 bbls/d at maturity.

Pads 12 and 13 were the first to be targeted at the higher quality resource across the entire lease rather than concentrating on the resource in the vicinity of the upgrader. Well logs and core data indicate these 18 wells are similar to our best producing wells on the lease, which are meeting or exceeding expectations. They also compare favorably with wells drilled on leases by other companies that match our performance expectations. Drilling on the two pads is in progress. Pad 12 is expected to start steaming in the second quarter of next year and pad 13 in the third quarter. Production is expected about three months after first steam and is expected to ramp-up to full rates over the following 12 to 18 months. We expect production from these two pads to contribute 11,000 to 17,000 bbls/d at maturity.

We plan to commence drilling 10 to 12 wells on pads 14 and 15 in 2012, subject to regulatory approvals. First steam to these wells is expected in late 2013. We expect production from these two pads to contribute 6,000 to 9,000 bbls/d at maturity.

We are also progressing the acceleration of the development of 25 to 30 wells at Kinosis, which is along the southern border of the Long Lake lease. Our core-hole analysis and reservoir understanding of Kinosis confirms the resource here has minimal lean zones and shale barriers. Well log and core data show these to be analogous to our best producing wells on Long Lake. Also, with core holes in place and regulatory approval at an advanced stage, we expect to be able to develop these well pairs faster than for pads beyond 14 and 15. Production from these wells is expected to contribute 15,000 to 25,000 bbls/d at maturity. We expect to provide details regarding timing and cost of this opportunity later this year.

We expect these wells to fill the upgrader and offset production declines in the initial 10 pads.

To further evaluate our Long Lake and Kinosis leases for future development, we are proceeding with a 200 well core-hole drilling program this winter. This program supports our sustaining development activities to keep the Long Lake upgrader full and to begin development of the rest of the Kinosis lease using our bitumen-leading strategy. This strategy allows us to ramp-up SAGD production while retaining flexibility in the timing of building additional upgraders to enhance the economics of the developments.

We are also planning to participate with a 25% working interest in a non-operated SAGD project at Hangingstone. Project sanctioning is expected late this year or early next year, and first steam would be in about 2014. Our share of production at full rates is expected to be about 6,000 bbls/d.

The upgrader continued to perform well with an on-stream factor of 91% and premium synthetic crude (PSC™) yield of 70%, compared to 93% and 74%, respectively, in the first quarter. In June, we successfully processed 45,000 bbls/d of produced and purchased bitumen, reaching upgrader throughput of about 65% of capacity. We will continue to purchase and upgrade third party volumes when market and operating conditions are appropriate.

Shale Gas

Northeast British Columbia

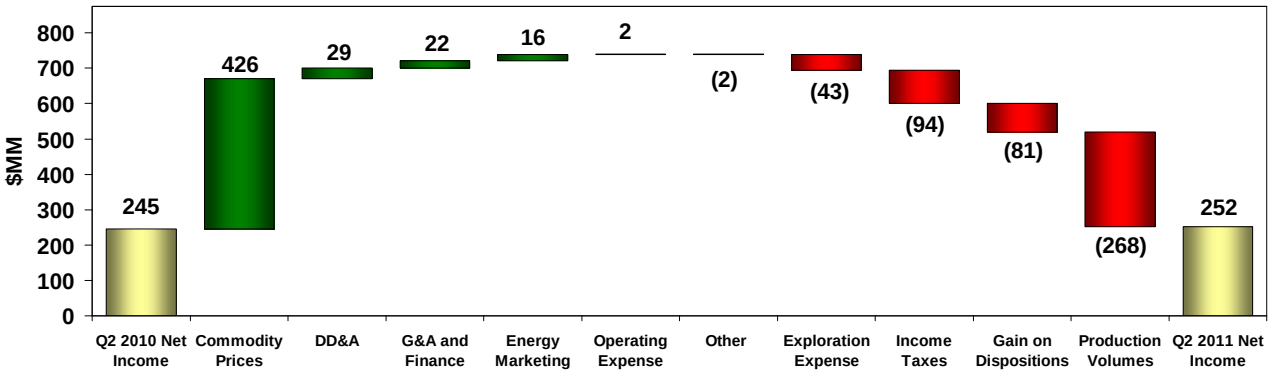
Our shale gas strategy is progressing as planned and production from the eight-well pad at Horn River brought on-stream late last year continues to meet expectations. Horn River production averaged approximately 40 mmcf/d during the quarter. Plans to increase production at Horn River later this year continued to progress with our successful drilling program on the nine-well pad. We also began fracing and completion activities on the wells during the quarter. Production from this nine-well pad is expected on-stream in the fourth quarter but will be limited to our existing facility capacity of about 50 mmcf/d. This capacity increases to 175 mmcf/d in late 2012 to coincide with the start-up of production from our 18-well pad. We commenced drilling this pad in late June and production is expected to come on-stream in the fourth quarter of 2012. Additional facility capacity is planned to be added as our production increases. Our process to seek a joint venture partner to accelerate value realization for a portion of our shale gas asset is proceeding on schedule with numerous parties accessing the data room.

FINANCIAL RESULTS

Change in Net Income

	2011 vs 2010	
	Three Months Ended June 30	Six Months Ended June 30
Net Income at June 30, 2010 [1]	245	386
Favorable (unfavorable) variances [2]:		
Production Volumes, After Royalties		
Crude Oil	(249)	(328)
Natural Gas	(1)	–
Changes in Crude Oil Inventory For Sale	(18)	(1)
Total Volume Variance	(268)	(329)
Realized Commodity Prices		
Crude Oil	421	705
Natural Gas	5	(16)
Total Price Variance	426	689
Operating Expense	2	(16)
Depreciation, Depletion, Amortization and Impairment	29	13
Exploration Expense	(43)	(76)
Energy Marketing Revenue, Net	16	78
General and Administrative Expense	(23)	(7)
Finance Costs	45	60
Net Gain on Dispositions	(81)	177
Income Taxes	(94)	(508)
Other	(2)	(13)
Net Income at June 30, 2011 [1]	**252**	**454**

[1] Includes results of discontinued operations (see Note 14 of our Unaudited Condensed Consolidated Financial Statements).
[2] All amounts are presented before provision for income taxes.



Significant variances in net income are explained further in the following sections.

OIL & GAS

Production (before royalties) [1]

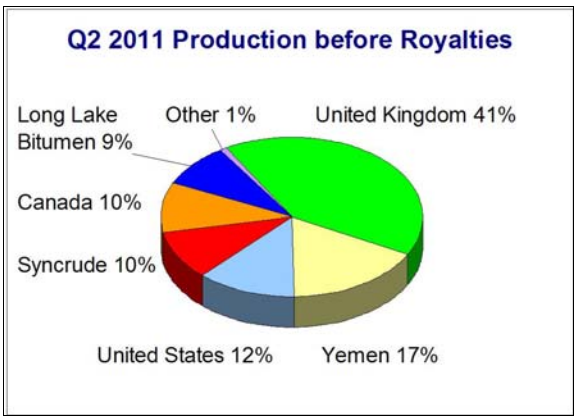
	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Crude Oil and Liquids (mbbls/d)				
United Kingdom	77.6	98.2	87.3	101.9
Yemen	34.7	40.9	36.5	41.9
Oil Sands – Syncrude	20.4	23.4	21.8	21.5
Oil Sands – Long Lake Bitumen	18.1	16.2	17.4	14.2
United States	8.9	9.9	9.0	9.8
Canada [2]	–	13.1	–	13.7
Other Countries	1.8	2.1	1.7	2.2
	161.5	203.8	173.7	205.2
Natural Gas (mmcf/d)				
United Kingdom	37	40	36	40
United States	96	96	99	98
Canada [2]	124	128	130	130
	257	264	265	268
Total Production (mboe/d)	204	248	218	250

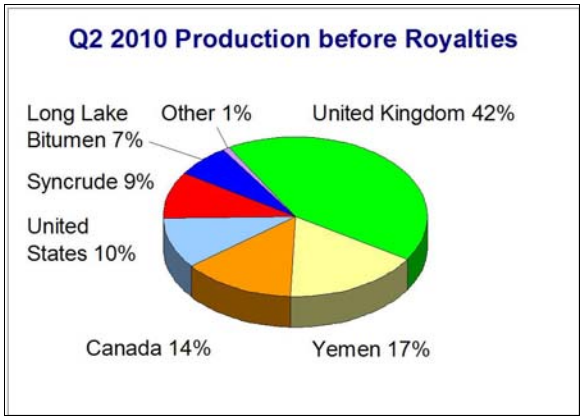
Production (after royalties)

	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Crude Oil and Liquids (mbbls/d)				
United Kingdom	77.3	98.2	87.1	101.9
Yemen	18.8	22.2	19.7	22.6
Oil Sands – Syncrude	17.8	21.5	20.1	19.7
Oil Sands – Long Lake Bitumen	16.9	15.7	16.3	13.5
United States	8.0	8.9	8.1	8.9
Canada [2]	–	10.0	–	10.4
Other Countries	1.6	2.0	1.6	2.1
	140.4	178.5	152.9	179.1
Natural Gas (mmcf/d)				
United Kingdom	37	40	36	40
United States	83	83	86	85
Canada [2]	119	117	123	119
	239	240	245	244
Total Production (mboe/d)	180	218	194	220

[1] We have presented production volumes before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.
[2] Includes the following production from discontinued operations. See Note 14 of our Unaudited Condensed Consolidated Financial Statements.

	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Before Royalties				
Crude Oil and NGLs (mbbls/d)	–	13.1	–	13.7
Natural Gas (mmcf/d)	–	11	–	11
After Royalties				
Crude Oil and NGLs (mbbls/d)	–	10.0	–	10.4
Natural Gas (mmcf/d)	–	10	–	10





Lower volumes reduced net income for the quarter by $268 million

Production before and after royalties was 18% lower than the second quarter of 2010, primarily as a result of: i) unscheduled maintenance in the UK; ii) the sale of our Canadian heavy oil properties in July 2010; and iii) natural field declines in Yemen. Compared to the first quarter of 2011, production before and after royalties decreased 12% and 13%, respectively, as Buzzard operated at reduced rates and Yemen production was impacted by natural field declines.

The following table summarizes our production volume changes since last quarter:

(mboe/d)	Before Royalties	After Royalties
Production, first quarter 2011	232	207
Production changes:		
United Kingdom	(19)	(19)
Yemen	(3)	(2)
Oil Sands – Syncrude	(3)	(4)
Oil Sands – Long Lake Bitumen	1	1
United States	(1)	(1)
Canada	(3)	(2)
Production, second quarter 2011	204	180

Production volumes in this section represent before-royalties volumes, net to our working interest.

UNITED KINGDOM

In the UK North Sea, quarterly production averaged 83,800 boe/d, 18% below the previous quarter and 20% lower than the second quarter of 2010.

Buzzard averaged 49,000 boe/d for the quarter, 31% lower than the previous quarter and the same period last year, due to unscheduled maintenance to repair the cooling system and interruptions to a third–party natural gas export pipeline which constrain oil production to minimize gas flaring. While the repair work proceeded on schedule, production was lower than expected due to the gas export restrictions. Production at Buzzard is expected to be back to full rates in August.

Unscheduled maintenance on the Buzzard cooling system began in the first quarter of 2011. During the second quarter, we installed a temporary cooling system for production. These maintenance issues combined with the reduced availability of the third-party natural gas export system, limited production capacity during the quarter. Permanent upgrades to the cooling system and completion of the start-up of the fourth platform are both expected to be completed in the third quarter. We utilized Buzzard's downtime to bring forward maintenance work originally scheduled for September. Further maintenance will be advanced to August when the third-party operated Forties pipeline system undergoes a one-week shutdown. As a result, the September shutdown will not be required.

Ettrick production increased marginally from the previous quarter, averaging 15,700 boe/d. Gas compression and power generation outages that impacted production in the first quarter were resolved early in the quarter and production has since returned to normal rates. Production at Ettrick increased 11% from the second quarter of 2010, when the facilities were ramping up following start up of the field.

Scott/Telford quarterly production averaged 18,300 boe/d. This is 20% higher than the previous quarter, when repairs to the natural gas export system limited production. Production from our non-operated fields at Duart and Farragon averaged 800 boe/d for the quarter.

YEMEN

Yemen production was 15% lower than the same period last year and 9% lower than the previous quarter. This reflects natural field declines following completion of development drilling activities as we near the end of the primary contract term in December of this year. A labour strike in May resulted in a two-day shutdown of our Yemen facilities. This was the longest disruption in our Yemen operations since production began in 1993. Following a successful restart, the facility has returned to normal production.

We remain confident that we can continue to manage our operations during the current period of uncertainty in the country. Safety and security continue to be our primary focus. Our current contract expires in mid–December unless we receive a contract extension. Contract extension negotiations have not progressed during the period.

OIL SANDS – SYNCRUDE

Syncrude production averaged 20,400 boe/d for the quarter, 13% lower than the second quarter of 2010 and 12% lower than the first quarter of 2011. Production was reduced by unscheduled maintenance to the LC finer and the vacuum distillation unit. The repairs have been completed and production subsequently returned to full rates. A turnaround of Coker 8–2 is scheduled for the third quarter of 2011, which is expected to temporarily reduce production rates.

OIL SANDS – LONG LAKE

At Long Lake, bitumen production averaged 18,100 boe/d (27,900 boe/d gross), up 1,500 boe/d from the first quarter. Production is increasing as a result of higher steam injection following the hot lime softener scheduled maintenance, well optimizations and the continuing ramp-up of the new pad 11 wells. Production at the end of June was approximately 30,000 bbls/d (gross) and we expect production from Long Lake to continue to increase into the mid-30,000 bbls/d (gross) range by year end.

UNITED STATES

Production in US Gulf of Mexico averaged 24,900 boe/d, 5% lower than the prior quarter and 4% lower than the same period last year. Longhorn averaged 8,400 boe/d for the quarter, 11% lower than the prior quarter due to scheduled maintenance at the third-party Corral platform in June. Production at Longhorn was 8% higher than the second quarter of 2010. Compared to the first quarter of 2011, production elsewhere in the Gulf of Mexico was marginally lower.

CANADA

Production in Canada decreased 9% from the previous quarter to average 20,700 boe/d. The decrease is primarily due to permanently shutting in our Balzac gas plant during the quarter and natural declines on other fields.

Shale gas production averaged 38 mmcf/d (6,400 boe/d) during the quarter, consistent with the previous quarter. Production was 31 mmcf/d (5,200 boe/d) higher than the same period last year from new wells brought on stream at the end of 2010. CBM production was comparable to prior periods at 7,000 boe/d.

Production in Canada decreased 40% from the same period last year when volumes included 14,900 boe/d of heavy oil production. These properties were sold in the third quarter of 2010.

OTHER COUNTRIES

Our share of production from the Guando field in Colombia decreased 14% from the same period last year primarily due to natural field declines. Production in Colombia remained fairly consistent with the previous quarter.

Commodity Prices

	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Crude Oil				
Dated Brent (Brent) (US$/bbl)	117.36	78.30	111.16	77.26
West Texas Intermediate (WTI) (US$/bbl)	102.56	78.03	98.33	78.37
Benchmark Differentials [1] (US$/bbl)				
Mars	9.28	(0.60)	8.31	(1.79)
Masila	12.92	0.68	11.43	(0.47)
Realized Prices from Producing Assets (Cdn$/bbl)				
United Kingdom	110.55	77.18	104.37	77.21
Yemen	111.77	80.50	107.00	80.44
Oil Sands – Syncrude	111.79	77.93	102.68	80.46
Oil Sands – Long Lake	108.78	74.08	100.67	76.80
United States	101.89	73.60	96.60	76.34
Canada	–	57.24	–	61.37
Other Countries	106.57	74.77	99.85	76.88
Corporate Average (Cdn$/bbl)	110.28	76.23	103.93	77.11
Natural Gas				
New York Mercantile Exchange (NYMEX) (US$/mmbtu)	4.37	4.34	4.29	4.69
AECO (Cdn$/mcf)	3.54	3.66	3.56	4.37
Realized Prices from Producing Assets (Cdn$/mcf)				
United Kingdom	8.20	4.80	7.76	4.80
United States	4.42	5.14	4.39	5.58
Canada	3.62	3.72	3.64	4.38
Corporate Average (Cdn$/mcf)	4.75	4.42	4.63	4.89
Nexen's Average Realized Oil and Gas Price (Cdn$/boe)	95.26	67.46	90.33	68.78
Average Foreign Exchange Rate – Canadian to US Dollar	1.0331	0.9731	1.0238	0.9673

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

Higher commodity prices increased quarterly net income $426 million

Crude oil prices continued to strengthen during the quarter. Brent increased 12% and WTI increased 9% from the previous quarter to average US$117.36/bbl and US$102.56/bbl, respectively, with the Brent premium widening 36% to US$14.80/bbl. Compared to the second quarter of 2010, while WTI increased 31%, Brent is 50% higher due to the current differential premium of almost $15.00/bbl between Brent and WTI. The stronger Canadian dollar mitigated the impact of the higher prices as we realized an average crude oil price for the quarter of $110.28/bbl. This is 45% higher than the same period last year and 12% higher than the prior quarter.

Our realized natural gas prices were 5% higher than the previous quarter to average $4.75/mcf. NYMEX averaged US$4.37/mmbtu and AECO prices decreased modestly to average $3.54/mcf. Compared to the second quarter of 2010, our realized gas price increased 7% as higher gas prices in the UK and modest increases in NYMEX rates were only partially offset by a 3% reduction in AECO rates.

The Canadian dollar strengthened against the US dollar. This reduced net sales by approximately $91 million compared to the second quarter of 2010, as our realized crude oil and natural gas prices were approximately $6.80/bbl and $0.29/mcf lower, respectively. The weaker US dollar, however, lowers our US-dollar denominated costs and debt when translated to Canadian dollars.

CRUDE OIL REFERENCE PRICES

The second quarter saw economic weakness that was priced into the commodity markets. The main factors that drove lower prices were concerns over China's inflation and the potential government's response to manage the economy, the European debt crisis that is creating a flight to safety in the US dollar, the end of the US Federal Reserve QE2 program, fears of decreased demand due to high prices, and no new geopolitical events that materialized in further supply disruptions.

The short-term bearish fundamentals for prices have been recently overshadowed by banks presenting increasingly bullish (US $120-$125/bbl) forecasts for Brent crude. Bullish sentiment is based on demand growth outpacing production as the effects of Japan's earthquake diminish, and weaker demand signals out of China fail to materialize. Short-term prices were affected by the unexpected release of 60 million barrels from the Strategic Petroleum Reserves by the International Energy Agency (IEA) in June, however, crude oil reference prices have since recovered.

Incremental OPEC production to replace the lost Libyan oil is providing the market with less desirable medium and heavy crudes, which many European refineries cannot efficiently process. This reduces crude oil stocks and if OPEC fails to increase output of lighter, more desirable crudes, demand will soon exceed supply, pushing crude prices higher.

CRUDE OIL DIFFERENTIALS

The Brent/WTI differential averaged at a premium of US$14.80/bbl for the quarter versus a premium of US$0.27/bbl for the second quarter of 2010. Oversupply at Cushing and its land lock nature will continue to keep WTI discounted to Brent until takeaway capacity from Cushing comes on stream in 2014-2015 to transport crude to the US Gulf Coast.

The Masila price differential to Brent averaged a premium of US$12.92/bbl as it continues to follow the upward movement in international crude prices and continued strong demand from Asian countries.

Mars, the primary benchmark for most of our Gulf oil production, is a medium sour crude that is priced to compete with comparable international import alternatives by Gulf Coast refineries. Since it is produced in the Gulf of Mexico, Mars has been competing with waterborne crudes which are pricing off Brent. With high Brent pricing, Mars is trading at a premium to WTI with the expectation it will continue until the pricing differences between Brent and WTI is closed.

In Canada, synthetic crude oil traded at an average premium of US$9.82/bbl over WTI for the quarter (10% over WTI). Strong synthetic pricing continues to be driven primarily by short-term supply disruptions and occasionally by the Brent/WTI spread. Supply disruptions will gradually ease and are expected to cease by the third quarter 2011. At times, strong Brent pricing supported the synthetic crude oil pricing as refiners looked to synthetic crude oil as an alternative to LLS (Light Louisiana Sweet). LLS is a waterborne crude and hence is influenced by Brent prices. Nexen receives synthetic crude oil pricing for both Syncrude synthetic crude and Long Lake PSC™.

NATURAL GAS REFERENCE PRICES

NYMEX natural gas traded as high as US$4.92/mmbtu in the second quarter as fundamentals and technical influences supported prices. Energy Information Administration (EIA) gas storage reports show near-term tighter balances. Market perception continues to be that medium-term balances will be tighter, partially driven by higher oil prices and brighter demand prospects linked to nuclear worries. Long-term fundamentals are driven by North American LNG export prospects moving further along in the approval process.

North American gas balances were impacted by weather, with cooler than normal temperatures boosting gas demand enough to level off the incremental production. Natural gas storage levels show a year-over-year deficit of 230 bcf. Despite a drop in the number of active rigs, US natural gas production increased on a year-over-year basis driven by rig efficiencies and the gas extracted from liquid-rich plays.

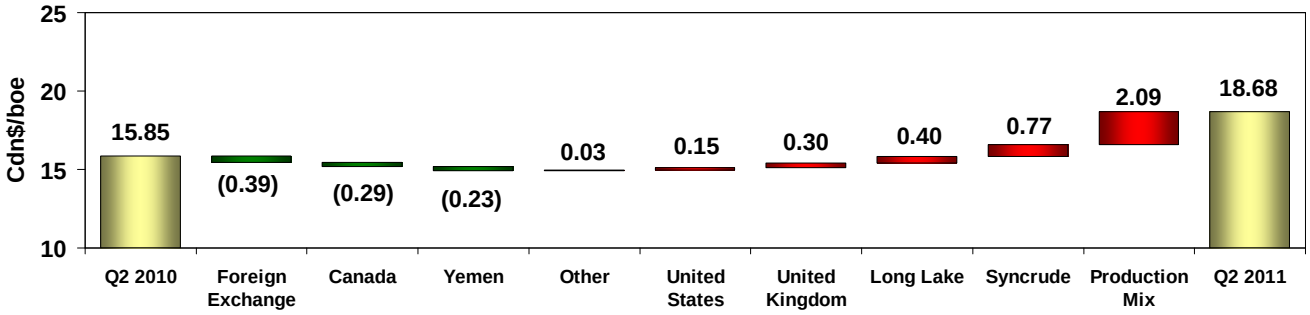
Reduced nuclear power also helped to boost demand which was offset by the US west coast gas demand losses driven by the region's hydro power recovery.

In the European natural gas market, UK gas prices are rising due to a cold spell in Europe, the disrupted Libyan pipeline and the incremental Japanese LNG demand due to the need to substitute the loss of nuclear power.

Operating Expenses [1]

(Cdn$/boe)	Three Months Ended June 30 2011	Three Months Ended June 30 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010
Operating expenses based on production before royalties [2]				
Conventional Oil and Gas	9.09	9.49	9.65	9.22
Oil Sands – Syncrude	39.98	32.67	37.92	34.10
Oil Sands – Long Lake [3]	95.34	89.95	92.56	111.84
Average Oil and Gas	18.68	15.85	17.95	15.39
Operating expenses based on production after royalties				
Conventional Oil and Gas	10.60	10.84	11.02	10.60
Oil Sands – Syncrude	45.67	35.49	41.34	37.15
Oil Sands – Long Lake [3]	104.92	93.32	99.78	116.72
Average Oil and Gas	21.64	17.93	20.33	17.55

[1] Includes results of discontinued operations (see Note 14 of our Unaudited Condensed Consolidated Financial Statements).
[2] Operating expenses per boe are our total oil and gas operating costs divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.
[3] Excludes activities related to third-party bitumen purchased, processed and sold.



Lower operating expenses increased net income by $2 million for the quarter

Operating costs were consistent with the same period last year. Per unit operating costs increased compared to last year, primarily due to temporary changes in our production with reduced volumes from Buzzard. Operating costs at Long Lake are higher than our corporate average, as those operating costs are mainly fixed. The change in production mix increased our corporate average by $2.09/boe.

In the UK North Sea, operating costs per barrel at Buzzard were higher as a result of higher maintenance and lower production, increasing our corporate average by $0.68/boe. Elsewhere in the UK North Sea, operating costs at Ettrick and Scott/Telford reduced our corporate average by $0.38/boe.

At Long Lake, unit operating costs have temporarily increased in the first half of the year with planned and unplanned maintenance, and initiatives to increase upgrader reliability and improve well performance. During the quarter, we completed planned maintenance on the second hot lime softener and a cogeneration unit, as well as unplanned outages on the sulfur recovery units and gasifiers. These costs at Long Lake increased our corporate average by $0.40/boe. The third hot lime softener unit and second cogeneration unit are scheduled to undergo maintenance in August.

In Yemen, the impact of reduced production volumes was offset by lower operating costs from reduced workovers and maintenance, decreasing our corporate average cost by $0.23/boe.

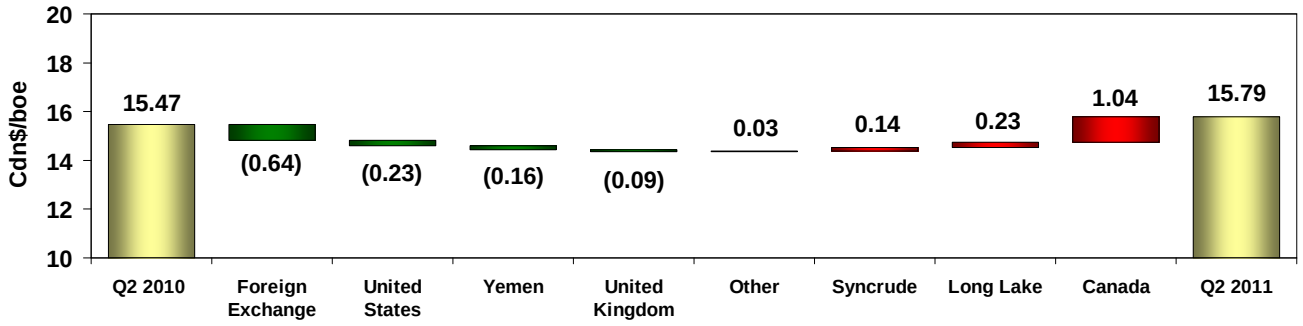
In the US Gulf of Mexico, surface maintenance and workover costs increased our corporate average by $0.15/boe. In Canada, the sale of our heavy oil properties reduced operating costs by $22 million from the same period last year and the shutdown of the Balzac gas plant in April reduced operating costs by $4 million from the same period last year. Combined, our corporate average was reduced by $0.29/boe.

Syncrude unit operating costs increased due to unplanned maintenance on the vacuum distillation unit and an LC finer. This, combined with lower production, increased our corporate average by $0.77/boe. The stronger Canadian dollar reduced our corporate average by $0.39/boe as operating costs of our international and US assets are denominated in US dollars.

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

(Cdn$/boe)	Three Months Ended June 30 2011	Three Months Ended June 30 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010
DD&A based on production before royalties [2]				
Conventional Oil and Gas	16.59	16.49	17.53	16.01
Oil Sands – Syncrude	7.89	6.56	7.66	6.81
Oil Sands – Long Lake	17.64	15.09	18.43	17.28
Average Oil and Gas	15.79	15.47	16.58	15.27
DD&A based on production after royalties				
Conventional Oil and Gas	19.34	18.85	20.02	18.42
Oil Sands – Syncrude	9.02	7.12	8.35	7.42
Oil Sands – Long Lake	19.02	15.63	19.65	17.94
Average Oil and Gas	18.24	17.05	18.75	17.40

[1] Includes results of discontinued operations (see Note 14 of our Unaudited Condensed Consolidated Financial Statements).
[2] DD&A per boe is our DD&A for oil and gas operations divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.



Lower oil and gas DD&A increased quarterly net income $29 million

On a per unit basis, DD&A increased $0.32/boe from the same period last year, primarily due to higher depletion rates in Canada and Long Lake. These increases were partially offset by the impact of a stronger Canadian dollar which reduced our corporate average by $0.64/boe, as depletion of our international and US assets are denominated in US dollars.

Depletion rates at Buzzard decreased as a result of additional reserves recognized at the end of 2010, due to production performance and successful drilling during the year. This reduced our corporate average depletion rate by $0.11/boe. The other UK properties increased our corporate average depletion rate by $0.02/boe as higher depletion rates at our Scott/Telford field were largely offset by lower depletion rates at Ettrick.

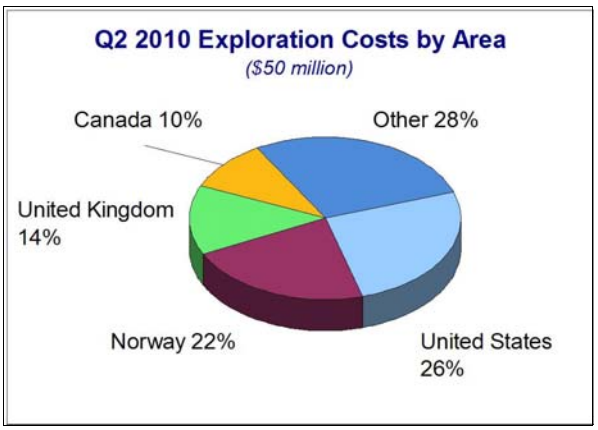
Depletion rates in Yemen decreased our corporate average by $0.16/boe as a result of reserve additions at the end of 2010, relating to positive production performance. In the US Gulf of Mexico, asset impairments in 2010 reduced the carrying value of our assets, thereby lowering the depletion rate. This reduced our corporate average depletion rate by $0.23/boe.

Canada production increased our corporate average DD&A rate by $1.04/boe, despite a decrease in our DD&A expense of $7 million due to the disposition of our heavy oil properties. This increase was driven by higher DD&A rates at the Balzac gas plant, which was shut down during the quarter. Our second quarter DD&A expense also includes a $31 million revision of future abandonment costs at our Crossfield wells.

At Long Lake, our depletion rate increased our corporate average by $0.23/boe as a result of a reduction in reserves at the end of 2010 partially offset by the impact of improved PSC™ yield on bitumen.

Exploration Expense

	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Seismic	14	17	27	29
Unsuccessful Drilling	10	1	34	42
Other	69	32	158	72
Total Exploration Expense	93	50	219	143



Higher exploration expense reduced net income for the quarter by $43 million

Exploration costs increased from the second quarter of 2010 as we continue to explore in our core basins in the Gulf of Mexico, the North Sea, offshore West Africa and Canada. Other exploration costs were $37 million higher, primarily due to increases in support costs, lease rental expenses and unutilized drilling rig costs in the Gulf of Mexico.

During the second quarter, we incurred $10 million in drilling costs associated with our unsuccessful Ronaldo well in the Norwegian North Sea. The well was drilled earlier in the year and costs of $24 million were expensed during the first quarter.

Seismic costs decreased 18% compared to the same period last year. Lower spending in the Gulf of Mexico and Norway was partially offset by additional seismic purchases in the North Sea and Canada. Seismic data costs will fluctuate depending on where we are in the evaluation process.

ENERGY MARKETING

Higher contribution from Energy Marketing increased net income by $16 million for the quarter

In the third quarter of 2010, we substantially completed the re-alignment of our energy marketing business to primarily focus on marketing crude oil production from North America, the North Sea and Yemen. The higher contribution in 2011 compared to the second quarter of 2010 was generated by improved results from our crude oil marketing business as a result of capturing gains on changing crude oil differentials, contango curve structure, lease and facilities, and blending of products. In the second quarter of 2010, the North American natural gas marketing group incurred losses primarily due to narrowing transportation spreads.

CORPORATE EXPENSES

General and Administrative (G&A) [1]

	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
General and Administrative Expense before Stock-Based Compensation	105	109	180	227
Stock-Based Compensation [2]	(29)	(56)	3	(51)
Total General and Administrative Expense	76	53	183	176

[1] Includes results of discontinued operations (see Note 14 of our Unaudited Condensed Consolidated Financial Statements).
[2] Includes cash and non-cash expenses related to our tandem option and stock appreciation rights plans.

Higher G&A costs decreased quarterly net income by $23 million

G&A expense in the quarter increased 43% from the same period last year as a result of our stock-based compensation expense. Fluctuations in our share price create volatility in net income as we account for stock-based compensation using the fair-value method. During the quarter, we recovered approximately $29 million of non-cash stock-based compensation that was recognized in prior periods as our share price decreased 10%. This compared to the second quarter of 2010 when our share price decreased approximately 17% and we recovered $61 million of non-cash stock-based compensation. Cash payments made in connection with our stock-based compensation programs during the three and six month period ended June 30, 2011 were $1 million and $5 million, respectively (2010 – $5 million and $8 million, respectively).

G&A expense before stock-based compensation decreased 4% from the second quarter of 2010, primarily due to lower employee costs as a result of our 2010 asset dispositions and marketing business re-alignment.

Finance Costs

	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Long-Term Debt Interest Expense	74	98	160	192
Accretion Expense Related to ARO	12	12	23	23
Other Interest Expense	3	17	10	21
	89	127	193	236
Less: Capitalized Borrowing Costs	(29)	(22)	(57)	(40)
Total Finance Costs [1]	60	105	136	196
Effective Interest Rate	6.7%	5.6%	6.6%	5.4%

[1] Includes results of discontinued operations (see Note 14 of our Unaudited Condensed Consolidated Financial Statements).

Lower finance costs increased net income by $45 million for the quarter

Lower interest costs and higher capitalized interest reduced finance costs by 43% compared to the second quarter of 2010. Interest costs were lower as a result of proceeds from our non-core disposition program. These proceeds allowed us to repay outstanding term credit facilities, repurchase and cancel US$812 million of fixed-rate debt and deconsolidate the debt associated with Canexus.

Capitalized interest on our Usan project, offshore West Africa, increased $9 million compared to the second quarter of 2010 as we near completion of the development. Elsewhere, interest was capitalized on the fourth platform at Buzzard and future phases of our insitu oil sands.

Income Taxes [1]

	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Current	384	264	808	523
Deferred	(52)	(26)	124	(99)
Total Provision for Income Taxes	332	238	932	424

[1] Includes results of discontinued operations (see Note 14 of our Unaudited Condensed Consolidated Financial Statements).

Higher taxes reduced net income $94 million for the quarter

In late March, the UK government substantively enacted an increase of 12% in the supplementary charge tax rate on North Sea oil and gas activities, which increased the UK statutory oil and gas income tax rate to 62%. The average tax rate on our North Sea oil and gas activities in 2011 is approximately 59%. This rate change increased our current income tax expense by $50 million in the second quarter. In the first quarter, the increased tax rate increased deferred income tax liabilities, resulting in a one-time, non-cash charge of $270 million.

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

Stronger commodity prices compared to the same period last year also contributed an increase to our income tax expense for the period. Our income tax provision includes current taxes in the United Kingdom, Yemen, Norway, Colombia and the United States.

Other

	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Gain on Sale of Disposition of Canexus	–	–	348	–
Loss on Debt Redemption and Repurchase	(1)	–	(91)	–
Gain on Sale of Non-core Assets	–	80	–	80

In April, we paid $525 million to redeem the US$500 million notes due in 2013. We incurred a $52 million loss on the transaction being the difference between carrying cost and the redemption price. In March, we paid $346 million to repurchase and cancel US$312 million of notes due in 2015 and 2017. We incurred a $39 million loss on the repurchase. We have realized $229 million of foreign exchange gains on this US-denominated debt since it was issued as the Canadian dollar has strengthened relative to the US dollar.

In February 2011, we completed the sale of our 62.7% investment in Canexus for gross proceeds of approximately $477 million. A gain of $348 million was realized in the previous quarter.

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

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure

	June 30 **2011**	December 31 **2010**
Net Debt [1, 2]		
Bank Debt	–	–
Public Senior Notes	3,720	4,647
Total Senior Debt	3,720	4,647
Subordinated Debt	430	443
Total Debt	4,150	5,090
Less: Cash and Cash Equivalents	(1,312)	(1,005)
Total Net Debt	2,838	4,085
Equity at Book Value	8,181	7,814

[1] Includes all of our borrowings and is calculated as long-term debt and short-term borrowings less cash and cash equivalents.
[2] Net debt is a non-GAAP measure and is reconciled to the nearest GAAP measure on page 23.

Net Debt

Our net debt levels are directly related to our operating cash flows and capital expenditure activities. Changes in net debt are related to:

	Three Months Ended June 30 **2011**	Six Months Ended June 30 **2011**
Capital Investment	(530)	(1,029)
Cash Flow from Operations [1, 2]	598	1,267
Excess Cash Flow Generated	68	238
Proceeds on Disposition of Assets	12	474
Dividends on Common Shares	(26)	(52)
Issue of Common Shares	8	31
Foreign Exchange Translation of US-dollar Debt and Cash	48	139
Net Change in Working Capital	475	603
Other	(73)	(186)
Decrease in Net Debt	512	1,247

[1] Includes results of discontinued operations (see Note 14 of our Unaudited Condensed Consolidated Financial Statements).
[2] Cash flow from operations is a non-GAAP measure and is reconciled to the nearest GAAP measure on page 23.

Our asset disposition program of the last 18 months successfully captured value and increased our financial capacity, while narrowing our focus to core growth strategies. The program contributed to a $3.1 billion decrease in net debt from $5.9 billion to $2.8 billion (52%) over the past two years. We also reduced our refinancing obligations in the next seven years to $200 million by removing near-term debt maturities.

Net debt decreased $1.2 billion from the end of 2010 as a result of the proceeds from the disposition of Canexus and generating excess cash flow (cash flow from operations less capital expenditures) and changes in working capital. During the quarter, we redeemed US$500 million of long-term debt using cash on hand. The stronger Canadian dollar also reduced our US-dollar denominated debt when translated into Canadian dollars.

Net debt can fluctuate from period-to-period. Net debt is expected to rise in the second half of the year due to the timing of our capital spending and working capital changes. Capital investment is expected to increase in the latter half of the year primarily due to increased drilling in the Gulf of Mexico, the North Sea, and Canadian shale gas and oil sands. Operating cash flows in the oil and gas industry can be volatile as short-term commodity prices are driven by existing supply and demand fundamentals and market volatility. Capital expenditures fluctuate depending on activities at any point in time. Changes in our non-cash working capital can vary between quarters as our working capital fluctuates depending on timing of settlement of outstanding positions, the movement in commodity prices, inventory cycles and timing of income tax installments.

Change in Working Capital

	June 30 **2011**	December 31 **2010**	Increase/ (Decrease)
Cash and Cash Equivalents	1,312	1,005	307
Restricted Cash	50	40	10
Accounts Receivable	1,871	1,789	82
Net Current Derivative Contracts	(8)	(19)	11
Inventories and Supplies	344	550	(206)
Accounts Payable and Accrued Liabilities	(2,988)	(2,459)	(529)
Other	48	33	15
Net Working Capital	629	939	

Net working capital decreased primarily as a result of the timing of current tax installments, the sale of commodity trading inventory and the timing of crude oil liftings.

Outlook for Remainder of 2011

We generate a large portion of our production volumes from a relatively small number of high-netback fields. While our focus on developing high-netback legacy assets provides us with a competitive advantage in our operating areas and delivers attractive value, it results in our production guidance being sensitive to operating rates in these areas.

Given the impact of operational events at Buzzard and Long Lake in the first half of the year, our annual production before royalties is now expected to be 210,000 to 230,000 boe/d. This is lower than we expected in May largely as a result of the gas export restrictions. The range reflects variability of production at Buzzard as we complete the cooling system repairs and the final stages of commissioning the fourth platform that will allow us to produce from our full suite of wells regardless of H_2S levels. It also reflects variability in Long Lake ramp-up, timing of Telford and Blackbird well tie-ins, and potential for hurricane disruptions in the Gulf of Mexico. The following provides production ranges by quarter and major areas:

	Average Daily Quarterly Production before Royalties				Average Daily Annual Production before Royalties
Crude Oil, NGLs and Natural Gas (mboe/d)	**Q1 2011 (actual)**	**Q2 2011 (actual)**	**Q3 2011 (estimate)**	**Q4 2011 (estimate)**	**2011 Annual (estimate)**
Buzzard	71	49	67 – 74	82 – 95	67 – 72
Other UK	32	35	23 – 27	24 – 32	28 – 32
Yemen	38	35	32 – 34	24 – 33	32 – 35
United States	26	25	20 – 24	21 – 24	23 – 25
Canada – Oil & Gas	23	20	19 – 21	19 – 22	20 – 22
Canada – Syncrude	23	20	19 – 22	20 – 23	20 – 22
Canada – Bitumen	17	18	18 – 21	18 – 24	18 – 20
Other Countries	2	2	2	2	2
Total	**232**	**204**	**200 – 225**	**210 – 255**	**210 – 230**

The production guidance ranges for the various assets reflect:

- In the UK:
  - Buzzard repairs of the cooling system and completion of the start-up of the fourth platform continues into the third quarter. The facility will also be taken down in early August for the planned one week shutdown of the third-party operated Forties pipeline. Once the fourth platform is available, production is expected to be strong as we will be able to almost double the number of wells as we bring our higher concentration sour producers on-stream.
  - Planned maintenance activities at Scott and Ettrick in the third quarter.
  - Production is expected to increase late in the year with the start-up of production from the tie-ins of the Telford TAC well to the Scott facility, and the Blackbird field to the Ettrick facility.
- In Yemen, production will continue with natural field declines. Our current contract expires in mid-December unless we receive a contract extension.
- In the US, the range of production is based on the potential for hurricane-related disruptions through the third quarter and into the early part of the fourth quarter.

- At Long Lake, the ongoing ramp-up of pad 11 and well optimizations are expected to contribute to modest production growth over the remainder of the year.

We expect to add new production next year with Usan coming on-stream in the first half of the year and the start-up of our 18–well shale gas pad and Long Lake pad 12 in the fourth quarter of the year.

Our future liquidity and ability to fully fund capital requirements generally depend upon operating cash flows, existing working capital, unused committed credit facilities and our ability to access debt and equity markets. Given the long cycle time of most of our development projects and volatile commodity prices, it is not unusual in any year for capital expenditures to exceed our cash flow. Changes in commodity prices, particularly crude oil as it represents approximately 80% of our production, can impact our operating cash flows. We use short-term contracts to sell the majority of our oil and gas production, exposing us to short-term price movements. A US$1/bbl change in crude oil prices above US$50/bbl is projected to increase or decrease our cash flow from operating activities, after cash taxes, by approximately $17 million for the second half of the year. Our exposure to a $0.01 change in the US to Canadian dollar exchange rate is projected to increase or decrease our cash flow by approximately $17 million for the second half of the year. We believe that our existing liquidity, balance sheet capacity and capital investment flexibility provide us with the ability to fund our ongoing obligations during periods of lower commodity prices.

At June 30, 2011, our available liquidity is $4.3 billion. This consists of approximately $1.3 billion cash on hand and $3 billion committed unsecured term credit facilities, which are available until 2016. Our term credit facilities supported $279 million of outstanding letters of credit at the end of the quarter. We also have $463 million of uncommitted, unsecured credit facilities, none of which was drawn and $24 million is being used to support outstanding letters of credit. The average weighted length-to-maturity of our public debt is approximately 23 years.

CONTRACTUAL OBLIGATIONS, COMMITMENTS AND GUARANTEES

We have assumed various contractual obligations and commitments in the normal course of our operations and financing activities. We included these obligations and commitments in our 2010 annual MD&A. Except as described below, there have been no other significant developments since year end. During the quarter, we entered into new drilling rig commitments in the UK North Sea and made additional office lease commitments, comprised of the following:

	2011	2012	2013	2014	2015	Thereafter
Drilling Rig Commitments	39	71	12	–	–	–
Operating Lease Commitments	–	2	5	6	7	50

CONTINGENCIES

There are a number of lawsuits and claims pending, the ultimate result of which cannot be ascertained at this time. We record costs as they are incurred or become determinable. We believe the resolution of these matters would not have a material adverse effect on our liquidity, consolidated financial position or results of operations. These matters are described in *Legal Proceedings and Regulatory Actions* in our 2010 Annual Information Form. There have been no significant developments since year-end.

NEW ACCOUNTING PRONOUNCEMENTS

IFRS Pronouncements

As part of our transition to IFRS, we adopted IFRS accounting standards in effect on January 1, 2011. The impact of adopting IFRS on shareholders' equity, cash flows, net income and comprehensive income is disclosed in Note 17 of the Unaudited Condensed Consolidated Financial Statements for the three and six months ended June 30, 2011. Our 2010 comparative financial information has been restated to be in accordance with our IFRS accounting policies as described in Note 2 of the Unaudited Condensed Consolidated Financial Statements for the three months ended March 31, 2011. We determined that the majority of our existing Canadian GAAP oil and gas accounting policies were appropriate under IFRS. Detailed analysis identified differences, the most significant of which are detailed in Note 17 *Transition to IFRS* of the Unaudited Condensed Financial Statements for the three and six months ended June 30, 2011.

The following standards and interpretations have not been adopted as they apply to future periods. They may result in changes to our existing accounting policies and other note disclosures. We are currently evaluating the impact these standards will have on our results of operations and financial position:

- 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 results of operations and financial position.
- 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 reclassed to income and those 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 annual 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.

INTERNAL CONTROL OVER FINANCIAL REPORTING

In connection with the adoption of IFRS, we established additional internal controls over financial reporting, as necessary, to review and validate the conversion to IFRS and relevant transitional activities including restatement of comparative financial information for 2010 and related disclosures. There were no other significant changes in internal controls over financial reporting during the six months ended June 30, 2011 that have materially affected, or are reasonably likely to materially effect, our internal controls over financial reporting.

EQUITY SECURITY REPURCHASES

During the quarter, we made no purchases of our equity securities.

SUMMARY OF QUARTERLY RESULTS

	Canadian GAAP [1]		IFRS [1]					
	2009		**2010**				**2011**	
(Cdn$ millions, except per share amounts)	Sep	Dec	Mar	Jun	Sep	Dec	Mar	Jun
Net Sales from Continuing Operations	919	1,375	1,347	1,305	1,322	1,522	1,598	1,507
Net Income (Loss) from Continuing Operations before Income Taxes is Comprised of:								
Oil and Gas	250	447	490	610	410	435	677	660
Corporate and Other [2, 3]	(48)	(61)	(202)	(136)	(388)	(90)	(228)	(76)
	202	386	288	474	22	345	449	584
Net Income (Loss) from Continuing Operations	102	249	111	238	(54)	161	(100)	252
Net Income	122	259	141	245	581	160	202	252
Earnings (Loss) Per Common Share from Continuing Operations ($/share)								
Basic	0.20	0.48	0.21	0.45	(0.10)	0.30	(0.19)	0.48
Diluted	0.17	0.47	0.20	0.42	(0.10)	0.30	(0.19)	0.45
Earnings Per Common Share ($/share)								
Basic	0.23	0.50	0.27	0.47	1.11	0.30	0.38	0.48
Diluted	0.21	0.49	0.26	0.43	1.10	0.30	0.38	0.45
Dividends Declared ($/share)	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
Common Share Price ($/share)								
Toronto Stock Exchange – High	25.94	27.31	25.91	26.91	22.33	23.00	27.11	25.47
Toronto Stock Exchange – Low	20.70	22.26	22.38	20.92	18.33	20.57	21.57	19.22
New York Stock Exchange – High (US$)	24.43	26.05	24.98	26.92	21.54	23.01	27.94	26.82
New York Stock Exchange – Low (US$)	18.68	20.66	21.06	19.66	17.20	20.12	21.71	19.43

[1] Prior to 2011, our financial statements were prepared in accordance with Canadian GAAP. In the first quarter of 2011, the company adopted IFRS with an effective date as at January 1, 2010 and restated the 2010 financial results to be in accordance with IFRS. Further details regarding our transition to IFRS are included in Note 17 of the Unaudited Condensed Consolidated Financial Statements for the three and six months ended June 30, 2011.

[2] The third quarter of 2010 includes asset disposition losses of $259 million and the fourth quarter includes asset disposition gains of $121 million related to our energy marketing business re-alignment.

[3] The first quarter of 2011 includes asset disposition gains of $348 million for Canexus.

NON-GAAP MEASURES

Cash Flow from Operations

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

	Three Months Ended			Six Months Ended	
(Cdn$ millions)	June 30 **2011**	March 31 **2011**	June 30 **2010**	June 30 **2011**	June 30 **2010**
Cash Flow from Operating Activities	1,014	736	533	1,750	1,345
Changes in Non-Cash Working Capital Including Income Taxes and Interest Payable	(419)	(66)	58	(485)	(198)
Other	11	7	(30)	18	(27)
Impact of Annual Crude Oil Put Options	(8)	(8)	(12)	(16)	(22)
Cash Flow from Operations	598	669	549	1,267	1,098

Net Debt

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

(Cdn$ millions)	As at June 30 **2011**	As at March 31 **2011**	As at June 30 **2010**
Bank Debt	–	–	930
Public Senior Notes	3,720	4,291	5,059
Total Senior Debt	3,720	4,291	5,989
Subordinated Debt	430	433	473
Total Debt	4,150	4,724	6,462
Less: Cash and Cash Equivalents	(1,312)	(1,374)	(970)
Total Net Debt	2,838	3,350	5,492

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Credit Risk

Most of our credit exposures are with counterparties in the energy industry, including integrated oil companies, crude oil refiners and utilities and are subject to normal industry credit risk.

At June 30, 2011:

- approximately 96% of our credit exposures were investment grade;
- approximately 75% of our credit exposures were with a diverse group of integrated oil companies, crude oil refiners and commodity marketers; and
- only two counterparties individually made up more than 10% of our credit exposure. These counterparties are major integrated oil companies with strong investment grade credit ratings.

Further information presented on market risks can be found in our 2010 annual MD&A and have not materially changed since December 31, 2010.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this MD&A constitute "forward-looking statements" (within the meaning of the United States *Private Securities Litigation Reform Act of 1995*, as amended) or "forward-looking information" (within the meaning of applicable Canadian securities legislation). Such statements or information (together "forward-looking statements") are generally identifiable by the forward-looking terminology used such as "*anticipate*", "*believe*", "*intend*", "*plan*", "*expect*", "*estimate*", "*budget*", "*outlook*", "*forecast*" or other similar words, and include statements relating to or associated with individual wells, regions or projects. Any statements regarding the following are forward-looking statements:

- future crude oil or natural gas prices;
- future production levels;
- future royalties and tax levels;
- future capital expenditures, their timing and their allocation to exploration and development activities;
- future earnings;
- future asset acquisitions or dispositions;
- future sources of funding for our capital program;
- future debt levels;
- availability of committed credit facilities;
- possible commerciality of our projects;
- development plans or capacity expansions;
- the expectation that we have the ability to substantially grow production at our oil sands facilities through controlled expansions;
- the expectation of achieving the production design rates from our oil sands facilities;
- the expectation that our oil sands production facilities continue to develop better and more sustainable practices;
- the expectation of cheaper and more technologically advanced operations;
- the expected design size of our 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;
- 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, will come on-stream or reach expected operating capacity; and
- changes in any of the foregoing.

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

All the forward-looking statement in this MD&A are qualified by the assumptions that are stated or inherent in such forward-looking statements. Although we believe that these assumptions are reasonable, 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 modification 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;
- risk related to accidents, blowouts and spills in connection with our offshore exploration, development and production activities, particularly our deepwater activities;
- direct and indirect risk related to the imposition of moratoriums, suspensions or cancellations of our offshore exploration, development and production operations, particular 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 and contractors, counterparties and joint venture partners;
- volatility in energy trading markets;
- foreign-currency exchange rates;
- economic conditions in the countries and regions in which we carry on business;
- governmental actions including changes to taxes or royalties, changes in environmental and other laws and regulations including without limitation, those related to our offshore exploration, development and production activities;
- renegotiations of contracts;
- results of litigation, arbitration or regulatory proceedings;
- political uncertainty, including actions by terrorists, insurgent or other groups, or other armed conflict, including conflict between states; and
- other factors, many of which are beyond our control.

These risks, uncertainties and other factors and their possible impact are discussed more fully in the sections titled *Risk Factors* in our 2010 Annual Information Form and *Quantitative and Qualitative Disclosures About Market Risk* in our 2010 annual MD&A. The impact of any one risk, uncertainty or factor on a particular forward-looking

statement is not determinable with certainty as these factors are interdependent, and management's future course of action would depend on our assessment of all information at that time.

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

Unaudited Condensed Consolidated Financial Statements

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

(Cdn$ millions, except per share amounts)	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Revenues and Other Income				
Net Sales	1,507	1,305	3,105	2,652
Marketing and Other Income (Note 13)	95	96	141	187
	1,602	1,401	3,246	2,839
Expenses				
Operating	341	321	704	644
Depreciation, Depletion, Amortization and Impairment	335	358	705	701
Transportation and Other	112	141	179	334
General and Administrative	76	40	181	149
Exploration	93	50	219	143
Finance (Note 8)	60	97	134	186
Loss on Debt Redemption and Repurchase (Note 7)	1	–	91	–
Net Gain from Dispositions	–	(80)	–	(80)
	1,018	927	2,213	2,077
Income from Continuing Operations before Provision for Income Taxes	584	474	1,033	762
Provision for (Recovery of) Income Taxes				
Current	384	264	808	523
Deferred	(52)	(28)	73	(110)
	332	236	881	413
Net Income from Continuing Operations	252	238	152	349
Net Income from Discontinued Operations, Net of Tax (Note 14)	–	7	302	37
Net Income Attributable to Nexen Inc.	252	245	454	386
Earnings Per Common Share from Continuing Operations ($/share)				
Basic	0.48	0.45	0.29	0.66
Diluted	0.45	0.42	0.27	0.62
Earnings Per Common Share ($/share)				
Basic	0.48	0.47	0.86	0.74
Diluted	0.45	0.43	0.84	0.69

See accompanying notes to the Unaudited Condensed Consolidated Financial Statements.

Nexen Inc.
Unaudited Condensed Consolidated Balance Sheet

(Cdn$ millions)	June 30 **2011**	December 31 **2010**	January 1 **2010**
Assets			
Current Assets			
Cash and Cash Equivalents	1,312	1,005	1,700
Restricted Cash	50	40	198
Accounts Receivable (Note 3)	1,871	1,789	2,322
Derivative Contracts	80	149	466
Inventories and Supplies (Note 4)	344	550	680
Other	148	142	185
Assets Held for Sale (Note 14)	–	729	–
Total Current Assets	3,805	4,404	5,551
Non-Current Assets			
Property, Plant and Equipment (Note 5)	14,628	14,579	14,669
Goodwill	276	286	330
Deferred Income Tax Assets	175	160	75
Derivative Contracts	27	116	225
Other Long-Term Assets	149	102	105
Total Assets	19,060	19,647	20,955
Liabilities			
Current Liabilities			
Accounts Payable and Accrued Liabilities (Note 6)	2,988	2,459	2,681
Derivative Contracts	88	168	456
Accrued Interest Payable	74	83	89
Dividends Payable	26	26	26
Liabilities Held for Sale (Note 14)	–	582	–
Total Current Liabilities	3,176	3,318	3,252
Non-Current Liabilities			
Long-Term Debt (Note 7)	4,150	5,090	7,259
Deferred Income Tax Liabilities	1,636	1,487	1,678
Asset Retirement Obligations (Note 9)	1,561	1,516	1,397
Derivative Contracts	35	115	210
Other Long-Term Liabilities	321	307	372
Equity (Note 11)			
Nexen Inc. Shareholders' Equity			
Common Shares	1,142	1,111	1,050
Retained Earnings	7,094	6,692	5,704
Accumulated Other Comprehensive Loss	(55)	(37)	–
Total Nexen Inc. Shareholders' Equity	8,181	7,766	6,754
Canexus Non-Controlling Interest (Note 14)	–	48	33
Total Equity	8,181	7,814	6,787
Commitments, Contingencies and Guarantees (Note 12)			
Total Liabilities and Equity	19,060	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 Six Months Ended June 30

(Cdn$ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Operating Activities				
Net Income from Continuing Operations	252	238	152	349
Net Income from Discontinued Operations	–	7	302	37
Charges and Credits to Income not Involving Cash (Note 15)	694	638	1,532	1,302
Exploration Expense	93	50	219	143
Income Taxes Paid	(69)	(43)	(460)	(250)
Interest Paid	(66)	(101)	(130)	(190)
Changes in Non-Cash Working Capital (Note 15)	121	(286)	153	(73)
Other	(11)	30	(18)	27
	1,014	533	1,750	1,345
Financing Activities				
Proceeds from Short-Term Borrowings	–	156	–	156
Repayment of Term Credit Facilities, Net	–	(1,077)	–	(1,077)
Repayment of Long-Term Debt (Note 7)	(525)	–	(871)	–
Proceeds from Canexus Long-Term Debt, Net	–	46	5	68
Dividends Paid on Common Shares	(26)	(26)	(52)	(52)
Issue of Common Shares and Exercise of Tandem Options for Shares	8	10	31	35
Other	(6)	(16)	(4)	(20)
	(549)	(907)	(891)	(890)
Investing Activities				
Capital Expenditures				
Exploration, Evaluation, and Development	(481)	(748)	(935)	(1,236)
Capitalized Interest Paid	(29)	(22)	(57)	(40)
Corporate and Other	(20)	(70)	(37)	(134)
Proceeds from Dispositions	12	81	474	96
Changes in Restricted Cash	(2)	68	(11)	83
Changes in Non-Cash Working Capital (Note 15)	31	(13)	115	75
Other	(23)	(4)	(75)	(7)
	(512)	(708)	(526)	(1,163)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(15)	55	(26)	(22)
Increase (Decrease) in Cash and Cash Equivalents	(62)	(1,027)	307	(730)
Cash and Cash Equivalents – Beginning of Period	1,374	1,997	1,005	1,700
Cash and Cash Equivalents – End of Period [1]	1,312	970	1,312	970

[1] Cash and cash equivalents at June 30, 2011 consists of cash of $218 million and short-term investments of $1,094 million (June 30, 2010 – cash of $237 million and short-term investments of $733 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 Six Months Ended June 30

(Cdn$ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Common Shares, Beginning of Period	1,134	1,077	1,111	1,050
Issue of Common Shares	8	8	31	32
Exercise of Tandem Options for Shares	–	2	–	3
Accrued Liability Relating to Tandem Options Exercised for Common Shares	–	1	–	3
Balance at End of Period	1,142	1,088	1,142	1,088
Retained Earnings, Beginning of Period	6,868	5,819	6,692	5,704
Net Income Attributable to Nexen Inc.	252	245	454	386
Dividends on Common Shares (Note 11)	(26)	(26)	(52)	(52)
Balance at End of Period	7,094	6,038	7,094	6,038
Accumulated Other Comprehensive Loss, Beginning of Period	(48)	(13)	(37)	–
Other Comprehensive Income (Loss) Attributable to Nexen Inc.	(7)	8	(18)	(5)
Balance at End of Period	(55)	(5)	(55)	(5)
Canexus Non-Controlling Interests, Beginning of Period	–	39	48	33
Net Income Attributable to Non-Controlling Interests	–	(6)	1	(1)
Distributions Declared to Non-Controlling Interests	–	(3)	–	(7)
Issue of Partnership Units to Non-Controlling Interests	–	12	–	17
Disposition of Canexus (Note 14)	–	–	(49)	–
Balance at End of Period	–	42	–	42

See accompanying notes to the Unaudited Condensed Consolidated Financial Statements.

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

(Cdn$ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Net Income	252	245	454	386
Other Comprehensive Income (Loss), Net of Income Taxes:				
Foreign Currency Translation Adjustment				
Net Gains (Losses) on Investment in Self-Sustaining Foreign Operations	(35)	221	(139)	66
Net Gains (Losses) on Foreign-Denominated Debt Hedging of Self-Sustaining Foreign Operations [1]	28	(213)	121	(71)
Other Comprehensive Income (Loss) Attributable to Nexen Inc.	(7)	8	(18)	(5)
Total Comprehensive Income	245	253	436	381

[1] Net of income tax expense for the three months ended June 30, 2011 of $4 million (2010 – net of income tax recovery of $31 million) and net of income tax expense for the six months ended June 30, 2011 of $17 million (2010 – net of income tax recovery of $11 million).

See accompanying notes to the Unaudited Condensed Consolidated Financial Statements.

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 six months ended June 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 six months ended June 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 July 13, 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. We are currently evaluating the impact that these standards will have on our results of operations and financial position:

- 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 results of operations and financial position.

- 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 reclassed to income and those that do not. The standard is required to be adopted for periods beginning on or after July 1, 2012. We 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

	June 30 **2011**	December 31 **2010**	January 1 **2010**
Trade			
Energy Marketing	1,069	929	1,410
Oil and Gas	706	822	823
Other	6	2	44
	1,781	1,753	2,277
Non-Trade	131	80	99
	1,912	1,833	2,376
Allowance for Doubtful Receivables	(41)	(44)	(54)
Total [1]	1,871	1,789	2,322

[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 June 30, 2011, December 31, 2010 and January 1, 2010.

4. INVENTORIES AND SUPPLIES

	June 30 **2011**	December 31 **2010**	January 1 **2010**
Finished Products			
Energy Marketing	223	452	548
Oil and Gas	58	35	25
Other	–	–	12
	281	487	585
Work in Process	7	5	7
Field Supplies	56	58	88
Total [1]	344	550	680

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

5. PROPERTY, PLANT AND EQUIPMENT

(a) Carrying amount of PP&E

	Exploration and Evaluation	Assets Under Construction	Producing Oil & Gas Properties	Corporate and Other	Total
Cost					
As at January 1, 2010	2,393	1,045	20,020	1,849	25,307
Additions	1,092	693	696	243	2,724
Disposals/Derecognitions	(70)	(8)	(1,638)	(122)	(1,838)
Transfers	(82)	78	4	–	–
Exploration Expense	(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	427	270	294	37	1,028
Disposals/Derecognitions	(43)	–	(51)	(11)	(105)
Transfers	(235)	235	–	–	–
Exploration Expense	(218)	–	(1)	–	(219)
Other	77	17	44	–	138
Effect of Changes in Exchange Rate	(27)	(59)	(330)	(3)	(419)
As at June 30, 2011	2,973	2,211	18,841	780	24,805
Accumulated 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)
Impairment Losses	–	–	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	24	–	645	36	705
Disposals/Derecognitions	(7)	–	(51)	(8)	(66)
Other	–	–	(2)	–	(2)
Effect of Changes in Exchange Rate	(7)	–	(253)	(3)	(263)
As at June 30, 2011	341	–	9,393	443	10,177
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 June 30, 2011	2,632	2,211	9,448	337	14,628

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 2010 includes non-cash impairment charges of $139 million for properties in the US Gulf of Mexico and Canada. In the second half of 2010, low natural gas prices, higher estimated future abandonment costs and declining production performance reduced properties' estimated future cash flows, which resulted in impairments for properties in the US Gulf of Mexico and Canada.

These properties were written down to their estimated fair value based on their estimated future discounted net cash flows. The estimated future cash flows incorporate a risk-adjusted discount rate and management's estimates of future prices, capital expenditures and production.

6. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	June 30 **2011**	December 31 **2010**	January 1 **2010**
Energy Marketing Payables	1,051	1,016	1,366
Accrued Payables	664	676	619
Income Taxes Payable	733	345	179
Trade Payables	176	164	210
Stock-Based Compensation	99	111	173
Other	265	147	134
Total [1]	2,988	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

	June 30 **2011**	December 31 **2010**	January 1 **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)	121	249	262
Notes, due 2017 (US$62 million) (c)	60	249	262
Notes, due 2019 (US$300 million)	289	298	314
Notes, due 2028 (US$200 million)	193	199	209
Notes, due 2032 (US$500 million)	482	497	523
Notes, due 2035 (US$790 million)	762	786	827
Notes, due 2037 (US$1,250 million)	1,205	1,243	1,308
Notes, due 2039 (US$700 million)	675	696	733
Subordinated Debentures, due 2043 (US$460 million)	444	457	481
	4,231	5,171	7,012
Unamortized debt issue costs	(81)	(81)	(88)
	4,150	5,090	6,924
Canexus debt	–	–	335
Total	4,150	5,090	7,259

(a) Term credit facilities

We have unsecured term credit facilities of $3 billion (US$3.1 billion) available until 2016, none of which were drawn at either June 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 six months ended June 30, 2011, we did not incur any interest expense on our term credit facilities. The weighted-average interest rate on our term credit facilities for the three months ended June 30, 2010 was 1.3% and 1.1% for the six months ended June 30, 2010. At June 30, 2011, $279 million (US$289 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

During the quarter, 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 during the first quarter as the difference between carrying value and the redemption price.

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

In the first quarter, 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 $463 million (US$481 million), none of which were drawn at either June 30, 2011 or December 31, 2010. We utilized $24 million (US$25 million) of these facilities to support outstanding letters of credit at June 30, 2011 (December 31, 2010—$112 million (US$112 million)). Interest is payable at floating rates.

8. FINANCE EXPENSE

	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Long-Term Debt Interest Expense	74	89	158	180
Accretion Expense related to Asset Retirement Obligations (Note 9)	12	9	23	19
Other Interest Expense	3	17	10	21
Total	89	115	191	220
Less: Capitalized at 6.5% (2010 – 5.2%)	(29)	(18)	(57)	(34)
Total [1]	60	97	134	186

[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:

	Six Months Ended June 30	Twelve Months Ended December 31
	2011	**2010**
ARO, Beginning of Period	1,571	1,432
Obligations Incurred with Development Activities	19	81
Changes in Estimates	42	332
Obligations Related to Dispositions	(3)	(224)
Obligations Settled	(25)	(43)
Accretion	23	47
Effects of Changes in Foreign Exchange Rate	(13)	(54)
ARO, End of Period	1,614	1,571
Of which:		
Due within Twelve Months [1]	53	55
Due after Twelve Months	1,561	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 3.0% (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 $367 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 June 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 six months ended June 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 Dragon 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 June 30, 2011, there were 527,014,110 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 (December 31, 2010 – nil; January 1, 2010 – nil).

(b) Dividends

Dividends paid per common share for the three months ended June 30, 2011 were $0.05 per common share (three months ended June 30, 2010 – $0.05). Dividends per common share for the six months ended June 30, 2011 were $0.10 per common share (six months ended June 30, 2010 – $0.10). Dividends paid to holders of common shares have been designated as “eligible dividends” for Canadian tax purposes. On July 13, 2011, the Board of Directors declared a quarterly dividend of $0.05 per common share, payable October 1, 2011 to the shareholders of record on September 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. During the quarter, we entered into new drilling rig commitments in the UK North Sea and made additional office lease commitments, comprised of the following:

	2011	**2012**	**2013**	**2014**	**2015**	**Thereafter**
Drilling Rig Commitments	39	71	12	–	–	–
Operating Lease Commitments	–	2	5	6	7	50

The commitments above are in addition to those included in Note 15 to the 2010 Audited Consolidated Financial Statements. Our operating leases, transportation and storage commitments, and other drilling rig commitments as at June 30, 2011 have not materially changed from the information previously disclosed in our 2010 Audited Consolidated Financial Statements.

13. MARKETING AND OTHER INCOME

	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Marketing Revenue, Net	51	113	102	196
Insurance Proceeds	26	–	26	–
Change in Fair Value of Crude Oil Put Options	–	2	(7)	(14)
Foreign Exchange Gains (Losses)	6	(11)	(16)	(2)
Other	12	(8)	36	7
Total	95	96	141	187

14. 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 June 30		
		2010	
	Canada	Chemicals	Total
Revenues and Other Income			
Net Sales	56	105	161
Other	–	(7)	(7)
	56	98	154
Expenses			
Operating	22	78	100
Depreciation, Depletion, Amortization and Impairment	7	8	15
Transportation and Other	–	12	12
General and Administrative	5	8	13
Finance	2	6	8
	36	112	148
Income (Loss) before Provision for Income Taxes	20	(14)	6
Less: Provision for Deferred Income Taxes	5	(3)	2
Income (Loss) before Non-Controlling Interest	15	(11)	4
Less: Non-Controlling Interest	–	(3)	(3)
Net Income (Loss) from Discontinued Operations, Net of Tax	15	(8)	7
Earnings Per Common Share			
Basic			0.02
Diluted			0.01

	Six Months Ended June 30			
	2011	**2010**		
	Chemicals	Canada	Chemicals	Total
Revenues and Other Income				
Net Sales	42	125	218	343
Other	(1)	–	–	–
Gain on Disposition	348	–	–	–
	389	125	218	343
Expenses				
Operating	25	45	148	193
Depreciation, Depletion, Amortization and Impairment	4	20	14	34
Transportation and Other	2	2	28	30
General and Administrative	2	9	18	27
Finance	2	3	7	10
	35	79	215	294
Income before Provision for Income Taxes	354	46	3	49
Less: Provision for Deferred Income Taxes	51	10	1	11
Income before Non-Controlling Interest	303	36	2	38
Less: Non-Controlling Interest	1	–	1	1
Net Income from Discontinued Operations, Net of Tax	302	36	1	37
Earnings Per Common Share				
Basic	0.57			0.08
Diluted	0.57			0.07

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 June 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	**729** [1]	**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	**582** [1]	**500**
Equity – Canexus Non-Controlling Interest	**48**	**33**

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

15. CASH FLOWS

(a) Charges and credits to income not involving cash

	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Depreciation, Depletion, Amortization and Impairment	335	358	705	701
Finance	60	97	134	186
Stock-Based Compensation	(29)	(61)	(2)	(59)
Loss on Debt Redemption and Repurchase	1	–	91	–
Non-cash Items Included in Discontinued Operations	–	27	(290)	60
Provision for Income Taxes	332	236	881	413
Foreign Exchange	(6)	(1)	17	1
Other	1	(18)	(4)	–
Total	694	638	1,532	1,302

(b) Changes in non-cash working capital

	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Accounts Receivable	194	(16)	(134)	(234)
Inventories and Supplies	163	(37)	184	76
Other Current Assets	(17)	5	(9)	78
Accounts Payable and Accrued Liabilities	(188)	(251)	227	82
Total	152	(299)	268	2
Relating to:				
Operating Activities	121	(286)	153	(73)
Investing Activities	31	(13)	115	75
Total	152	(299)	268	2

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 and Poland. 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. Net income of our operating segments excludes interest income, interest expense, unallocated corporate expenses and foreign exchange gains and losses. Identifiable assets are those used in the operations of the segments.

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

	Conventional			Oil Sands		Corporate and Other	Total
	United Kingdom	North America	Other Countries [1]	In Situ	Syncrude		
Net Sales	764	134	229	188	181	11	1,507
Marketing and Other Income	1	30	3	–	1	60	95
	765	164	232	188	182	71	1,602
Less: Expenses							
Operating	61	36	35	127	75	7	341
Depreciation, Depletion, Amortization and Impairment	133	116	23	36	14	13	335
Transportation and Other	–	11	11	51	6	33	112
General and Administrative	2	19	8	2	–	45	76
Exploration	13	41	37 [2]	2	–	–	93
Finance	5	4	1	–	2	48	60
Net Loss on Debt Redemption	–	–	–	–	–	1	1
Income (Loss) from Continuing Operations before Income Taxes	551	(63)	117	(30)	85	(76)	584
Less: Provision for (Recovery of) Income Taxes	326	(15)	22	(7)	21	(15)	332
Net Income (Loss)	**225**	**(48)**	**95**	**(23)**	**64**	**(61)**	**252**
Capital Expenditures	**104**	**123**	**171**	**91**	**27**	**14**	**530**

[1] Includes results of conventional crude oil and natural gas operations in Yemen and Colombia.
[2] Includes exploration activities primarily in Yemen, Nigeria, Norway, Colombia and Poland.

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

	Conventional			Oil Sands		Corporate and Other	Total
	United Kingdom	North America	Other Countries [1]	In Situ	Syncrude		
Net Sales	735	133	171	102	152	12	1,305
Marketing and Other Income	4	1	3	–	1	87	96
	739	134	174	102	153	99	1,401
Less: Expenses							
Operating	77	44	38	85	70	7	321
Depreciation, Depletion, Amortization and Impairment	189	92	25	25	13	14	358
Transportation and Other	1	5	3	32	4	96	141
General and Administrative	–	11	(1)	–	–	30	40
Exploration	7	18	24 [2]	1	–	–	50
Finance	4	4	–	–	1	88	97
Net Gain from Dispositions	–	–	–	(80) [3]	–	–	(80)
Income (Loss) from Continuing Operations before Income Taxes	461	(40)	85	39	65	(136)	474
Less: Provision for (Recovery of) Income Taxes	230	(10)	22	10	16	(32)	236
Income (Loss) from Continuing Operations	231	(30)	63	29	49	(104)	238
Add: Net Income (Loss) from Discontinued Operations (Note 14)	–	15	–	–	–	(8)	7
Net Income (Loss)	**231**	**(15)**	**63**	**29**	**49**	**(112)**	**245**
Capital Expenditures	**150**	**380**	**170**	**45**	**25**	**70**	**840**

[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.

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

	Conventional			Oil Sands		Corporate and Other	Total
	United Kingdom	North America	Other Countries [1]	In Situ	Syncrude		
Net Sales	1,726	267	414	303	370	25	3,105
Marketing and Other Income	17	32	7	–	1	84	141
	1,743	299	421	303	371	109	3,246
Less: Expenses							
Operating	159	76	70	234	150	15	704
Depreciation, Depletion, Amortization and Impairment	315	221	48	65	30	26	705
Transportation and Other	–	15	16	69	12	67	179
General and Administrative	(10)	52	23	13	–	103	181
Exploration	17	100	100 [2]	2	–	–	219
Finance	10	8	1	1	3	111	134
Net Loss on Debt Redemption	–	–	–	–	–	91	91
Income (Loss) from Continuing Operations before Income Taxes	1,252	(173)	163	(81)	176	(304)	1,033
Less: Provision for (Recovery of) Income Taxes	1,012	(46)	4	(20)	44	(113)	881
Income (Loss) from Continuing Operations	240	(127)	159	(61)	132	(191)	152
Add: Net Income from Discontinued Operations (Note 14)	–	–	–	–	–	302	302
Net Income (Loss)	**240**	**(127)**	**159**	**(61)**	**132**	**111**	**454**
Capital Expenditures	**178**	**242**	**317**	**220**	**46**	**26**	**1,029**

[1] Includes results of conventional crude oil and natural gas operations in Yemen and Colombia.
[2] Includes exploration activities primarily in Yemen, Nigeria, Norway, Colombia and Poland.

Segmented net income for the six months ended June 30, 2010

	Conventional			Oil Sands		Corporate and Other	Total
	United Kingdom	North America	Other Countries [1]	In Situ	Syncrude		
Net Sales	1,490	294	368	193	286	21	2,652
Marketing and Other Income	9	1	8	–	2	167	187
	1,499	295	376	193	288	188	2,839
Less: Expenses							
Operating	154	82	80	180	132	16	644
Depreciation, Depletion, Amortization and Impairment	353	190	62	40	27	29	701
Transportation and Other	4	10	6	83	11	220	334
General and Administrative	13	30	8	4	–	94	149
Exploration	31	41	70 [2]	1	–	–	143
Finance	8	8	–	1	2	167	186
Net Gain from Dispositions	–	–	–	(80) [3]	–	–	(80)
Income (Loss) from Continuing Operations before Income Taxes	936	(66)	150	(36)	116	(338)	762
Less: Provision for (Recovery of) Income Taxes	468	(17)	21	(9)	29	(79)	413
Income (Loss) from Continuing Operations	468	(49)	129	(27)	87	(259)	349
Add: Net Income from Discontinued Operations (Note 14)	–	36	–	–	–	1	37
Net Income (Loss)	**468**	**(13)**	**129**	**(27)**	**87**	**(258)**	**386**
Capital Expenditures	**277**	**527**	**313**	**109**	**49**	**135**	**1,410**

[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.

Segmented assets as at June 30, 2011

	Conventional			Oil Sands		Corporate and Other	Total
	United Kingdom	North America	Other Countries	In Situ	Syncrude		
Total Assets	**4,423**	**3,199**	**1,822**	**5,982**	**1,272**	**2,362 [1]**	**19,060**
Property, Plant and Equipment							
Cost	6,332	6,484	3,840	5,975	1,563	611	24,805
Less: Accumulated DD&A	3,277	3,670	2,348	145	387	350	10,177
Net Book Value	**3,055**	**2,814 [2]**	**1,492 [3]**	**5,830 [4]**	**1,176**	**261**	**14,628**
Goodwill	**269**	**–**	**–**	**–**	**–**	**7**	**276**

[1] Includes cash of $583 million, and Energy Marketing accounts receivable and inventory of $1,292 million.
[2] Includes capitalized costs of $1,070 million associated with our Canadian shale gas operations.
[3] Includes $1,398 million related to our Usan development, offshore Nigeria.
[4] Includes net book value of $4,962 million for Long Lake Phase 1 and $868 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. 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 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**	June 30 **2010**	December 31 **2010**
Shareholders' Equity under Canadian GAAP		**7,646**	**8,080**	**8,791**
Differences increasing (decreasing) reported shareholders' equity:				
Borrowing Costs	(i)	(841)	(814)	(778)
Asset Retirement Obligations	(ii)	(228)	(252)	(241)
Employee Benefits	(iii)	(104)	(104)	(150)
Stock-Based Compensation	(iv)	(96)	(81)	(92)
Property, Plant & Equipment	(v)	(124)	(112)	(90)
Foreign Exchange	(vi)	(11)	(9)	–
Long-term Debt	(vii)	(9)	(26)	(28)
Income Taxes	(viii)	554	473	429
Other		–	8	(27)
Shareholders' Equity under IFRS		**6,787**	**7,163**	**7,814**

(i) Borrowing Costs

We applied the IFRS 1 exemption to prospectively capitalize borrowing costs 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 it's 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 June 30 2010	Six Months Ended June 30 2010	Twelve Months Ended December 31 2010
Net Income under Canadian GAAP		**255**	**440**	**1,197**
Differences increasing (decreasing) reported net income:				
Borrowing Costs	(i)	16	27	63
Asset Retirement Obligations	(ii)	(7)	(24)	(13)
Stock-Based Compensation	(iii)	23	14	3
Property, Plant & Equipment	(iv)	4	12	34
Long-term Debt	(v)	(13)	(17)	(19)
Income Taxes	(vi)	(54)	(81)	(136)
Other		21	15	(2)
Total Differences in Net Income		**(10)**	**(54)**	**(70)**
Net Income under IFRS		**245**	**386**	**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 $59 million for the three and six months ended June 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 $25 million and $22 million for the three and six months ended June 30, 2010, respectively, and $19 million for the twelve months ended December 31, 2010.

Reconciliation of Comprehensive Income

(Cdn$ millions)	**Note**	Three Months Ended June 30 **2010**	Six Months Ended June 30 **2010**	Twelve Months Ended December 31 **2010**
Comprehensive Income under Canadian GAAP		**267**	**441**	**1,168**
Differences increasing (decreasing) reported comprehensive income, net of income taxes:				
Differences in net income		(10)	(54)	(70)
Foreign Currency Translation	(i)	(4)	(6)	(8)
Employee Benefits	(ii)	–	–	(35)
Comprehensive Income under IFRS		**253**	**381**	**1,055**

(i) Foreign Currency Translation

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

(ii) Employee Benefits

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

Nexen Inc.
Oil and Gas Prices and Cash Netback [1]

(all dollar amounts in Cdn$ unless noted)	Quarters – 2011 1st	2nd	3rd	4th	Quarters – 2010 1st	2nd	3rd	4th	Total Year 2010
PRICES:									
Brent Crude Oil (US$/bbl)	104.97	117.36			76.23	78.30	76.86	86.48	79.47
WTI Crude Oil (US$/bbl)	94.10	102.56			78.71	78.03	76.20	85.12	79.52
Nexen Average – Oil (Cdn$/bbl)	98.37	110.28			78.00	76.23	77.03	84.47	78.94
NYMEX Natural Gas (US$/mmbtu)	4.20	4.37			5.04	4.34	4.24	3.97	4.39
AECO Natural Gas (Cdn$/mcf)	3.58	3.54			5.08	3.66	3.52	3.41	3.92
Nexen Average – Gas (Cdn$/mcf)	4.51	4.75			5.37	4.42	4.18	4.16	4.54
NETBACKS [1]:									
United Kingdom									
Crude Oil:									
Sales (mbbls/d)	104.2	73.3			106.5	102.1	103.9	110.0	105.6
Price Received ($/bbl)	99.97	110.55			77.24	77.18	77.45	83.88	79.02
Natural Gas:									
Sales (mmcf/d)	36	37			33	41	29	38	36
Price Received ($/mcf)	7.29	8.20			4.81	4.80	5.11	6.34	5.28
Total Sales Volume (mboe/d)	110.2	79.5			112.1	109.0	108.8	116.3	111.5
Price Received ($/boe)	96.91	105.76			74.84	74.12	75.35	81.37	76.51
Operating Costs	9.85	8.48			7.60	7.85	8.41	9.19	8.28
Netback	87.06	97.28			67.24	66.27	66.94	72.18	68.23
United States									
Crude Oil:									
Sales (mbbls/d)	9.2	8.9			9.8	9.9	9.8	10.1	9.9
Price Received ($/bbl)	91.39	101.89			79.12	73.60	73.72	80.41	76.73
Natural Gas:									
Sales (mmcf/d)	103	96			101	95	102	99	99
Price Received ($/mcf)	4.36	4.42			6.00	5.14	4.70	4.05	4.97
Total Sales Volume (mboe/d)	26.3	24.9			26.6	25.8	26.9	26.6	26.5
Price Received ($/boe)	48.91	53.56			51.92	47.23	44.85	45.55	47.35
Royalties & Other	5.65	6.11			4.92	4.86	5.10	(0.63)	3.55
Operating Costs	10.43	10.72			8.96	10.90	9.44	10.78	10.02
Netback	32.83	36.73			38.04	31.47	30.31	35.40	33.78
Canada – Natural Gas									
Sales (mmcf/d) [2]	97	85			124	121	107	104	114
Price Received ($/mcf)	3.65	3.62			5.02	3.72	3.43	3.48	3.94
Royalties & Other	0.28	0.24			0.40	0.34	0.26	0.24	0.32
Operating Costs	1.70	1.54			1.70	1.89	1.90	1.55	1.76
Netback	1.67	1.84			2.92	1.49	1.27	1.69	1.86
Yemen									
Sales (mbbls/d)	34.9	39.3			47.3	39.3	43.5	38.8	42.2
Price Received ($/bbl)	101.57	111.77			80.39	80.50	79.33	87.82	81.86
Royalties & Other	46.98	52.26			37.52	36.65	34.75	37.72	36.65
Operating Costs	10.75	9.18			9.67	10.01	9.46	12.05	10.25
In-country Taxes	13.48	16.26			10.14	10.97	10.70	11.52	10.80
Netback	30.36	34.07			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 1st	2nd	3rd	4th	Quarters – 2010 1st	2nd	3rd	4th	Total Year 2010
Other Countries									
Sales (mbbls/d)	1.8	1.7			2.3	2.1	2.0	1.9	2.1
Price Received ($/bbl)	93.52	106.57			78.88	74.77	75.93	77.63	76.83
Royalties & Other	6.22	6.93			5.72	5.28	5.22	5.24	5.37
Operating Costs	8.11	10.19			5.58	7.42	6.98	8.19	6.99
Netback	79.19	89.45			67.58	62.07	63.73	64.20	64.47
In Situ [2]									
Sales (mbbls/d)	12.9	14.3			6.6	10.3	11.9	12.1	10.3
Price Received ($/bbl)	89.82	108.78			81.04	74.08	70.64	82.99	77.07
Royalties & Other	3.58	6.05			4.37	2.98	3.08	3.81	3.65
Operating Costs	89.43	95.34			154.00	89.95	84.75	85.61	100.09
Netback [2]	(3.19)	7.39			(77.33)	(18.84)	(17.19)	(6.43)	(26.67)
Syncrude									
Sales (mbbls/d)	23.2	20.4			19.5	23.4	19.1	22.8	21.2
Price Received ($/bbl)	94.60	111.79			83.55	77.93	78.27	85.12	81.23
Royalties & Other	4.30	13.82			7.09	6.37	4.82	6.72	6.27
Operating Costs	36.11	39.98			35.84	32.67	38.06	31.65	34.34
Netback	54.19	57.99			40.62	38.89	35.39	46.75	40.62
Company-Wide									
Oil and Gas Sales (mboe/d)	225.5	196.4			249.1	243.1	232.9	235.9	240.2
Price Received ($/boe)	85.98	95.26			70.16	67.56	68.23	74.49	70.11
Royalties & Other	8.74	13.42			9.38	8.05	7.96	7.13	8.16
Operating & Other Costs [2]	17.32	18.68			14.93	15.85	15.42	15.97	15.48
In-country Taxes	2.08	3.29			1.92	1.76	2.00	1.89	1.90
Netback	57.84	59.87			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.
Production Volumes (before royalties) [1]

	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Crude Oil and Liquids (mbbls/d)				
United Kingdom	77.6	98.2	87.3	101.9
Yemen	34.7	40.9	36.5	41.9
Oil Sands – Syncrude	20.4	23.4	21.8	21.5
Oil Sands – Long Lake Bitumen	18.1	16.2	17.4	14.2
United States	8.9	9.9	9.0	9.8
Canada [2]	–	13.1	–	13.7
Other Countries	1.8	2.1	1.7	2.2
	161.5	203.8	173.7	205.2
Natural Gas (mmcf/d)				
United Kingdom	37	40	36	40
United States	96	96	99	98
Canada [2]	124	128	130	130
	257	264	265	268
Total Production (mboe/d)	204	248	218	250

Production Volumes (after royalties)

	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Crude Oil and Liquids (mbbls/d)				
United Kingdom	77.3	98.2	87.1	101.9
Yemen	18.8	22.2	19.7	22.6
Oil Sands – Syncrude	17.8	21.5	20.1	19.7
Oil Sands – Long Lake Bitumen	16.9	15.7	16.3	13.5
United States	8.0	8.9	8.1	8.9
Canada [2]	–	10.0	–	10.4
Other Countries	1.6	2.0	1.6	2.1
	140.4	178.5	152.9	179.1
Natural Gas (mmcf/d)				
United Kingdom	37	40	36	40
United States	83	83	86	85
Canada [2]	119	117	123	119
	239	240	245	244
Total Production (mboe/d)	180	218	194	220

[1] We have presented production volumes before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.
[2] Includes the following production from discontinued operations in Note 14 to our Unaudited Condensed Consolidated Financial Statements.

	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Before Royalties				
Crude Oil and NGLs (mbbls/d)	–	13.1	–	13.7
Natural Gas (mmcf/d)	–	11	–	11
After Royalties				
Crude Oil and NGLs (mbbls/d)	–	10.0	–	10.4
Natural Gas (mmcf/d)	–	10	–	10

Cash Flow from Operations [1]

(Cdn$ millions)	Three Months Ended June 30 2011	Three Months Ended March 31 2011	Three Months Ended June 30 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010
Conventional Oil & Gas					
United Kingdom	699	887	658	1,586	1,325
North America [2]	91	65	91	156	229
Other Countries [3]	115	96	86	211	191
Oil Sands					
In Situ	6	(19)	(19)	(13)	(77)
Syncrude	103	107	80	210	145
	1,014	1,136	896	2,150	1,813
Interest, Marketing and Other Corporate Items [2]	(90)	(85)	(122)	(175)	(274)
Income Taxes [4]	(326)	(382)	(225)	(708)	(441)
Cash Flow from Operations [1]	598	669	549	1,267	1,098

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 June 30 2011	Three Months Ended March 31 2011	Three Months Ended June 30 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010
Cash Flow from Operating Activities	1.014	736	533	1,750	1,345
Changes in Non-Cash Working Capital Including Income Taxes and Interest Payable	(419)	(66)	58	485	(198)
Other	11	7	(30)	18	(27)
Impact of Annual Crude Oil Put Options	(8)	(8)	(12)	(16)	(22)
Cash Flow from Operations	598	669	549	1,267	1,098
Weighted-average Number of Common Shares Outstanding (millions of shares)	527.0	526.3	524.5	526.6	524.0
Cash Flow from Operations Per Common Share ($/share)	1.13	1.27	1.05	2.40	2.10

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 $58 million for the three months ended June 30, 2011 (March 31, 2011 – $42 million; June 30, 2010 – $39 million) and $100 million for the six months ended June 30, 2011 (2010 – $82 million).
4 Excludes in-country cash taxes in Yemen.

CORPORATE INFORMATION

OFFICERS

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

Marvin F. Romanow
President and
Chief Executive Officer

Kevin J. Reinhart
Executive Vice President
and Chief Financial Officer

Matthew J. Fox
Executive Vice President,
International

Gary H. Nieuwenburg
Executive Vice President, Canada

James T. Arnold
Senior Vice President,
Synthetic Crude

Eric B. Miller
Senior Vice President, General Counsel
and Secretary

Una M. Power
Senior Vice President, Corporate
Planning and Business Development

Catherine J. Hughes
Vice President,
Operational Services, Technology
and Human Resources

Kim D. McKenzie
Vice President and Chief Information
Officer

Kevin J. McLachlan
Vice President, Global Exploration

J. Michael Backus
Treasurer

Brendon T. Muller
Controller and Vice President, Insurance

Rick C. Beingessner
Assistant Secretary

C. James Cummings
Assistant Secretary

DIRECTORS

William B. Berry

Robert G. Bertram

Thomas W. Ebbern

Dennis G. Flanagan

S. Barry Jackson

Kevin J. Jenkins

The Hon. A. Anne McLellan, P.C., O.C.

Eric P. Newell, O.C.

Thomas C. O'Neill

Marvin F. Romanow

Francis M. Saville, Q.C.

Arthur R.A. Scace, C.M., Q.C.

John M. Willson

Victor J. Zaleschuk

For more information on our directors and officers, please see pages 55 and 59 in our Annual Information Form or visit www.nexeninc.com.

WEBSITE

Nexen's statistical supplement and other financial documents are available online at www.nexeninc.com.

Hard copies may be ordered via the Investor section of our website or by calling 403.699.5931.

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403.699.4000
www.nexeninc.com

STOCK SYMBOL: NXY

Toronto Stock Exchange
New York Stock Exchange

SUBORDINATED NOTES

7.35% due 2043
TSX: NXY.PR.U
NYSE: NXYPRB

DIVIDEND REINVESTMENT PLAN

A copy of the offering circular (and for United States residents, a prospectus) and authorization form may be obtained by calling CIBC Mellon Trust Company at 1.800.387.0825 or on the internet at www.cibcmellon.com.

AUDITORS

Deloitte & Touche LLP
Calgary, Alberta

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