

# MANAGEMENT'S DISCUSSION AND ANALYSIS

Despite economic volatility,  
2008 had record results reflecting strong  
oil prices and solid netbacks.

ITEM 7.  
Management's Discussion and Analysis  
of Financial Condition and Results of Operations

The following should be read in conjunction with the Consolidated Financial Statements included in this report. The Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles (GAAP) in Canada. The impact of significant differences between Canadian and United States (US) accounting principles on the financial statements is disclosed in Note 23 to the Consolidated Financial Statements. The date of this discussion is February 11, 2009. Unless otherwise noted, tabular amounts are in millions of Canadian dollars. Our discussion and analysis of our oil and gas activities include our Syncrude activities since the product produced from Syncrude competes in the oil and gas market. Oil and gas volumes, reserves and related performance measures are presented on a working interest before-royalties basis. We measure our performance in this manner consistent with other Canadian oil and gas companies. Where appropriate, we have provided information on an after-royalty basis in tabular format.

<sup>1</sup> Investors should read the Special Note Regarding Forward-Looking Statements on page 78.

<sup>2</sup> Canadian investors should read the Special Note to Canadian Investors on page 79 which highlights differences between our reserve estimates and related disclosures that are otherwise required by Canadian regulatory authorities.

Executive Summary	39
Capital Investment	41
Financial Results	
Year-to-Year Change in Net Income	46
Oil & Gas And Syncrude	
Production	47
Commodity Prices	50
Operating Expenses	52
Depreciation, Depletion, Amortization and Impairment (DD&A)	53
Exploration Expense	54
Oil & Gas and Syncrude Netbacks	56
Energy Marketing	57
Chemicals	62
Corporate Expenses	62
Outlook For 2009	64
Liquidity and Capital Resources	65
Critical Accounting Estimates	70
New Accounting Pronouncements	73
ITEM 7A.	
Quantitative and Qualitative Disclosures about Market Risk	75
Non-trading	75
Trading	77
Credit Risk	78
Special Note Regarding Forward-looking Statements	78
Special Note to Canadian Investors	79

## EXECUTIVE SUMMARY

### 2008 Results

(Cdn\$ millions)	2008	2007	2006
Production before Royalties (mboe/d) <sup>1</sup>	250	254	212
Production after Royalties (mboe/d)	210	207	156
Cash Flow from Operating Activities	4,354	2,830	2,374
Net Income	1,715	1,086	601
Earnings per Common Share, Basic (\$/share)	3.26	2.06	1.15
Net Debt <sup>2</sup>	4,575	4,404	4,730

<sup>1</sup> Production before royalties reflects our working interest before royalties and includes production of synthetic crude oil from Syncrude. We have presented our working interest before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.

<sup>2</sup> Long-term debt and short-term borrowings less cash and cash equivalents.

Production before royalties averaged 250,000 boe/d in 2008, slightly below last year's volumes. Higher rates at Buzzard were offset by declines at our maturing Yemen properties and hurricane interruptions in the Gulf of Mexico. Buzzard continues to operate reliably and production in 2008 averaged 204,200 boe/d (88,200 boe/d net to us). We expect our consolidated production rates will increase in 2009 primarily as a result of new volumes from our Long Lake Project, Ettrick in the UK North Sea and Longhorn in the Gulf of Mexico.

We achieved record financial results in 2008, generating cash flow from operating activities in excess of \$4 billion and net income of \$1.7 billion. Commodity prices reached new highs during the year, but fell in the fourth quarter as a result of the global economic crisis. WTI crude oil averaged US\$99.65/bbl for the year, 38% higher than last year. Despite the fall in crude oil and gas prices in the last part of the year, the strengthening US dollar kept our price realizations strong.

Much of our production has low operating costs and low royalties. Our cash netbacks continue to be among the highest in the industry, averaging \$72.97/boe after royalties for the year. High netbacks deliver superior relative performance even as commodity prices decline.

The past year proved challenging for our energy marketing group as unprecedented market conditions impacted physical market fundamentals and the pricing relationships we successfully positioned ourselves to profit from historically. While the global economic slowdown produced challenges for our business,

the marketing team was most impacted by significant swings in commodity markets. We were positioned to take advantage of normal market fundamentals but these were overwhelmed by significant price movements, increased volatility and the economic slowdown. Since the middle of the year, we have been refocusing this division and reducing the size of our trading levels. In response to the rapidly deteriorating economic environment and financial markets, we were carefully choosing our exit points. With the gas trading positions we recently exited, the refocusing of our gas marketing business back to physical transportation and storage is now complete.

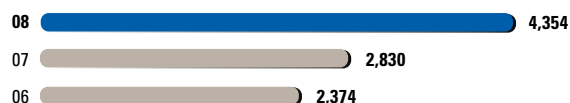
Our net income includes impairment expense of \$568 million (before tax) related to properties in the UK North Sea and the Gulf of Mexico. These properties were impaired by lower commodity prices, lower reserve estimates and unexpected costs.

We reduced our net debt by approximately \$1.3 billion with cash flow that exceeded our capital investment. This was offset by the impact of a stronger US dollar which increased our US-dollar denominated debt by \$1 billion at year end, and by repurchasing 12 million common shares for approximately \$340 million.

Our financial position is strong. We have financial flexibility with major capital projects complete at Buzzard and Long Lake, and industry-leading cash netbacks. We have liquidity of approximately \$3.5 billion after acquiring the additional Long Lake interest in January 2009, comprised of cash on hand and undrawn committed credit. We have no debt maturities until 2011 and the average term-to-maturity of our long-term debt is approximately 18 years.

#### CASH FLOW FROM OPERATING ACTIVITIES

(Cdn\$ millions)



#### NET INCOME

(Cdn\$ millions)



## Strategy Progress

(Cdn\$ millions)

	2008	2007	2006
Capital Investment, including Acquisitions	3,066	3,401	3,408
Proved Oil and Gas Reserves before Royalties (mmboe) <sup>1</sup>	664	734	725
Proved Oil and Gas Reserves after Royalties (mmboe) <sup>1</sup>	631	650	637
Proved Syncrude Reserves before Royalties (mmboe) <sup>1</sup>	324	324	324
Proved Syncrude Reserves after Royalties (mmboe) <sup>1</sup>	295	267	274

<sup>1</sup> Includes developed and undeveloped proved reserves as at December 31.

Our strategy is to build a sustainable energy company focused in three areas: oil sands, unconventional gas and select conventional exploration and exploitation. Our investment in these areas generated the following results in 2008:

- Oil Sands—the Long Lake Project began producing bitumen and we completed construction and commissioning of the upgrader. First production of premium synthetic crude from the upgrader began in January 2009. We continued to focus on our oil sands growth strategy by increasing our interest in Long Lake by 15% to 65% in early 2009.
- Unconventional Gas—we have a significant land position in the Horn River basin in northeast British Columbia and started to test the area with exploration drilling and fracing activities. We continued to explore and develop CBM opportunities in Canada.
- Select Conventional Exploration and Exploitation—our conventional exploration program was focused in the US Gulf of Mexico and the UK North Sea, which yielded four discoveries that provide opportunities for future growth.

During 2008, our proved oil and gas and Syncrude reserves additions replaced 25% of our oil and gas and Syncrude production (112% after royalties). Excluding economic revisions, we replaced 79% of our oil and gas and Syncrude production (86% after royalties). The difference between before and after royalties reflect a reduction in the royalties on oil sands activities where the royalty rate is sensitive to prices.

### Before Royalties

(mmboe)	Oil and Gas	Syncrude	Total
<b>Production</b>	<b>86</b>	<b>8</b>	<b>94</b>
<b>Reserve Changes excluding Production</b>			
Net Additions	66	8	74
Economic Revisions	(50)	–	(50)
	<b>16</b>	<b>8</b>	<b>24</b>

### After Royalties

(mmboe)	Oil and Gas	Syncrude	Total
<b>Production</b>	<b>72</b>	<b>7</b>	<b>79</b>
<b>Reserve Changes excluding Production</b>			
Net Additions	60	7	67
Economic Revisions	(7)	28	21
	<b>53</b>	<b>35</b>	<b>88</b>

The majority of our additions before economic revisions relate to activities at Buzzard, Long Lake, Masila and Canadian CBM. Negative revisions occurred at Ettrick as a result of disappointing drilling and testing results which caused us to reduce our expectations of recoverable reserves. Additional information on our proved oil and gas and Syncrude reserves can be found in Items 1 and 2 Business and Properties (pages 15 to 20) and in Item 8 Financial Statements and Supplementary Data (pages 126 to 131).

## Outlook

In 2009, we expect production to grow approximately 5% to 10% compared to 2008 and range between 255,000 and 270,000 boe/d before royalties. On an after-royalties basis, we expect production to grow 7% to 14% and range between 225,000 and 240,000 boe/d, reflecting growth in the UK North Sea and at Long Lake where royalties are low. Increases are expected to come from Ettrick in the UK North Sea, Longhorn in the US Gulf of Mexico and the Long Lake Project as bitumen rates ramp up.

Our capital investment plans for 2009 total \$2.8 billion. We plan to finance this investment through cash flow from operating activities and existing cash and cash equivalents. The primary focus of our investment will be on our major and core asset developments at Buzzard and Ettrick in the North Sea, Longhorn in the Gulf of Mexico, and Usan, offshore Nigeria. We also plan

to spend approximately \$700 million advancing our new growth exploration and appraisal opportunities including our Horn River shale gas play. We are monitoring our capital spending throughout the upcoming year and are prepared to reduce our capital budget in response to the economic environment.

Our large capital projects at Buzzard and Long Lake Phase 1 are behind us and at year end, we had over \$2 billion of cash on hand, \$2.5 billion of undrawn committed credit facilities that are available until 2012 and \$613 million in uncommitted credit facilities. We used existing term credit facilities and cash on hand early in 2009 to increase our interest in the Long Lake Project by 15%. We have no debt maturities over the next few years and believe we will continue to have substantial liquidity that provides us with the financial strength and flexibility to weather low commodity prices during this uncertain time. The average term-to-maturity of our debt is approximately 18 years.

## CAPITAL INVESTMENT

<i>(Cdn\$ millions)</i>	<b>Estimated 2009</b>	<b>2008</b>	<b>2007</b>
Major Development	780	1,437	1,479
Early Stage Development	210	167	162
New Growth Exploration	690	582	573
Core Asset Development	880	731	1,069
Total Oil & Gas and Syncrude	2,560	2,917	3,283
Energy Marketing, Corporate, Chemicals and Other	270	149	118
<b>Total Capital</b>	<b>2,830</b>	<b>3,066</b>	<b>3,401</b>

Our strategy and capital programs are focused on growing long-term 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
- exploration and new growth projects for longer-term growth.

As conventional basins in North America mature, we have been transitioning toward less mature basins and unconventional resource plays. Key focus areas include the North Sea, Athabasca oil sands, Canadian CBM and shale gas, deep-water Gulf of Mexico, offshore West Africa and the Middle East—areas we believe have attractive fiscal terms, significant remaining opportunity, and where we have a competitive advantage.

## 2008 Capital

<i>(Cdn\$ millions)</i>	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas					
Synthetic (mainly Long Lake)	847	156	2	20	1,025
United States	87	–	154	164	405
United Kingdom	263	–	146	282	691
Canada	63	11	223	105	402
Yemen	–	–	9	92	101
Nigeria	177	–	3	–	180
Other Countries	–	–	45	13	58
Syncrude	–	–	–	55	55
	<b>1,437</b>	<b>167</b>	<b>582</b>	<b>731</b>	<b>2,917</b>
Chemicals	–	–	–	88	88
Energy Marketing, Corporate and Other	–	–	–	61	61
<b>Total Capital</b>	<b>1,437</b>	<b>167</b>	<b>582</b>	<b>880</b>	<b>3,066</b>
As a % of Total Capital	47%	5%	19%	29%	100%

## 2009 Estimated Capital

<i>(Cdn\$ millions)</i>	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas					
Synthetic (mainly Long Lake)	–	180	–	110	290
United States	105	10	190	60	365
United Kingdom	160	10	175	400	745
Canada	–	10	180	90	280
Yemen	–	–	–	120	120
Nigeria	515	–	25	–	540
Other Countries	–	–	120	10	130
Syncrude	–	–	–	90	90
	<b>780</b>	<b>210</b>	<b>690</b>	<b>880</b>	<b>2,560</b>
Chemicals	–	–	–	194	194
Marketing, Corporate and Other	–	–	–	76	76
<b>Total Capital</b>	<b>780</b>	<b>210</b>	<b>690</b>	<b>1,150</b>	<b>2,830</b>
As a % of Total Capital	28%	7%	24%	41%	100%

### Synthetic

In 2008, we invested \$1 billion to develop our insitu oil sands resource. This included an investment of approximately \$847 million on the first phase of Long Lake, \$425 million of which related to the upgrader. The remaining expenditures related to preliminary work for future phases of Long Lake. At Long Lake, we added 19 mmboe of proved bitumen reserves based on further core-hole delineation of the lease.

In late January 2009, we completed the \$735 million acquisition of an additional 15% interest in the Long Lake Project and the joint venture lands from OPTI Canada Ltd. We now own 65% of the Long Lake Project and joint venture lands. As part of the transaction, we assumed operatorship of the upgrader from Opti, and are now the sole operator of the Long Lake Project. We expect this will create operational efficiencies and reduce

the cost of managing Long Lake. With the completion of this acquisition, our total company proved reserves have increased by approximately 9%. These additions will be booked in 2009.

We recently reached a significant milestone at Long Lake when we produced first Premium Synthetic Crude (PSC™) from the upgrader. The main process units of the upgrader have been successfully started up and are operating. Synthetic natural gas (Syngas) from the upgrader is being used in SAGD operations and this has significantly reduced the need for purchased natural gas. Currently, we are producing between 10,000 and 15,000 bbls/d gross of upgraded on-spec product. The upgrader is expected to ramp up to full design rates of approximately 60,000 bbls/d (39,000 bbls/d net to us) over the next 12 to 18 months. As the upgrader ramps up to full capacity, we expect that there will be periods of downtime as we work through the

early stages of production. This periodic downtime is normal and consistent with industry experience.

Bitumen production from the reservoir is performing well but our overall ramp up of production has been affected by a variety of surface issues that have limited the amount of steam injected into the reservoir over the past few months. Since steam injection rates directly impact bitumen production rates, when our ability to generate steam is limited, our bitumen production is lower. Most recently, our SAGD production was reduced as a result of power disruptions, extreme cold weather and water treating issues. As the weather improves and we recover from power disruptions and water treatment issues, our production rates have increased. We are currently producing approximately 20,000 bbls/d (gross) of bitumen, the highest we have seen to date. Due to steaming constraints, we have been forced to allocate our steam injection and accordingly we have 32 of the 81 well pairs on production. On average, these well pairs are producing at approximately 75% of their design rates after 11 months of SAGD operation. This is consistent with expectations as we expected a ramp up period of 12 to 18 months. The average steam-to-oil ratio (SOR) for these wells is currently less than 4.0. As we increase our steam capacity, we will bring on all remaining wells.

Phase 1 of Long Lake will develop approximately 10% of our oil sands inventory. The sanctioning of Phase 2 will depend on multiple factors including the initial performance of Phase 1, receiving regulatory approval for Phase 2 SAGD operations, receiving clarity on proposed climate change regulations, finalizing cost estimates and an improved economic environment. We therefore do not expect to sanction Phase 2 until mid 2010 at the earliest. In 2009, we plan to advance detailed engineering on the SAGD and upgrader facilities for Phase 2 of Long Lake and conduct core hole drilling to further delineate our leases.

#### United States

Development of Longhorn continues to progress with first production expected in mid 2009. This development comprises four sub-sea wells tied in to the ENI-operated Corral Platform, previously known as the Crystal Platform. We expect peak production rates in excess of 200 mmcf/d gross (50 mmcf/d net to us) by year end. In 2008, we invested \$87 million developing Longhorn. We have a 25% non-operated working interest in Longhorn and ENI is the operator.

In 2008, our exploration program primarily focused on the deep water. In the eastern Gulf of Mexico, we drilled the Fredericksburg exploration well. Target sands were reached but we did not encounter commercial hydrocarbons. This was the third prospect to be drilled in the area following earlier successes at Vicksburg and Shiloh. We remain optimistic about the potential of this emerging play and expect to drill up to two exploration wells and one appraisal well in the area in 2009. In addition, we have a feasibility study underway to assess development options for the Vicksburg discovery. We have a 25% interest in Vicksburg and a 20% interest in Shiloh with Shell operating both.

At our Cote de Mer prospect, located on the Louisiana coast, exploratory drilling was interrupted by hurricanes Gustav and Ike. Following successful pipe recovery operations, the well was sidetracked to a depth of 21,700 feet, and penetrated the target zone. We continue to be encouraged by the logging data received to date, and are attempting to drill the remaining 600 feet of the target interval. We have a 37.5% working interest in this prospect.

In 2008, we invested \$164 million to add production volumes from the Green Canyon 6 area and to recompleting wells on our producing properties.

#### United Kingdom

We invested almost \$700 million in the UK last year. This included approximately \$250 million at Buzzard and added proved reserves of 29 mmboe (29 after royalties). Successful drilling and production performance resulted in increases in both reservoir size and overall recovery factor which led to these proved reserve adds. These additions were offset by negative economic revisions of 10 mmboe (10 after royalties) due to low year-end prices.

In 2009, Buzzard will continue to be a significant contributor to our cash flow and production volumes. Throughout the year, we will continue construction of the fourth platform containing production sweetening facilities designed to handle higher levels of hydrogen sulphide. During the third quarter, we plan to install the jackets for this platform and complete tie-in operations, pending installation of the topsides. This will result in about one month of downtime which coincides with a six week planned slowdown of the Forties pipeline.

Our Ettrick development in the North Sea is progressing towards first oil in the next few months. In 2008, we invested approximately \$260 million. During 2008, we had 12 mmboe of negative reserve revisions (12 after royalties), of which approximately one quarter relate to lower oil prices. The remaining revisions are due to disappointing drilling results that lowered our reserve estimates. The Ettrick development consists of a leased floating production, storage and offloading vessel (FPSO) designed to handle 30,000 bbls/d of oil and 35 mmcf/d of gas. We expect Ettrick to add approximately 10,000 boe/d to our 2009 production volumes. We also have a discovery at Blackbird which could be a future tie-back to Ettrick. We have no proven reserves booked for Blackbird. In 2009, we plan to drill an appraisal well to further evaluate this discovery. We operate both Ettrick and Blackbird, with an 80% working interest in each.

We recently drilled a successful appraisal well at Rochelle on Block 15/27 in the North Sea. The well was tested and flowed at an average restricted rate of 41 mmcf/d of gas and 2,300 bbls/d of oil condensate. We are evaluating future appraisal and fast-track development options and have a 44% non-operated working interest in the well.

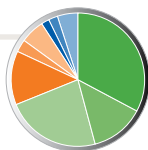
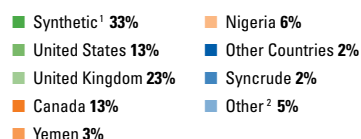
Elsewhere, we are assessing future appraisal and development alternatives for the growing Golden Eagle area. This area includes discoveries at Golden Eagle, Pink and most recently, Hobby, where we are encouraged by early results. We are planning to drill multiple sidetracks to determine the extent of both Hobby and Golden Eagle. Hobby is located on Block 20/1N approximately 1.5 km west of the Golden Eagle discovery. We have a 34% interest in both Hobby and Golden Eagle, a 46% interest in Pink, and operate all three. We have identified additional prospects in the area and have plans for further exploratory and appraisal drilling this year.

## Canada

As conventional basins in Canada mature, we are focusing our investment on unconventional resource plays such as shale gas and CBM. In northeast British Columbia, we have a material land position of approximately 126,000 acres with a 100% working interest in an emerging Devonian shale gas play. This play has the potential to be one of the most significant shale gas plays in North America. Our landholdings include approximately 88,000 acres in the Dilly Creek area of the Horn River basin. In 2008, we invested approximately \$180 million to drill, complete and test wells, and build infrastructure. One horizontal well was completed and tied in last winter and is producing at rates in line with our expectations and competitor wells. We expect to complete and tie-in two wells later this winter. We continue to construct all season roads to provide year-round access to our lands. In 2009, we plan to enhance our understanding of drilling and fracing techniques for this play with an investment plan that includes drilling and testing multiple wells from a single pad. We expect three of these wells to be drilled and completed by mid-year and on production before winter. The remaining wells will be drilled in the future if economic and financial conditions improve. Further appraisal activity is required before we can finalize estimates, establish commerciality and book proved reserves.

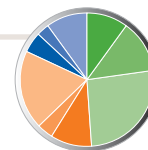
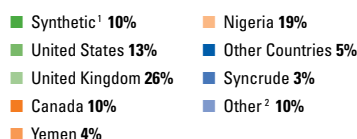
In 2008, we invested approximately \$115 million in exploration and development activities on our CBM lands and recognized 10 mmboe of proved reserves (10 after royalties). We expect our CBM reserves to grow over the coming years as additional wells are drilled, development work progresses and more production history is obtained. Our CBM production continues to increase as existing wells dewater and we bring new wells on stream. In 2008, our production increased 65% and we exited the year producing approximately 50 mmcf/d. Performance is in line with expectations and underscores the increasing value of our CBM assets.

### 2008 CAPITAL



- 1 Mainly Long Lake.
- 2 Marketing, Corporate and Other.

### 2009 ESTIMATED CAPITAL



- 1 Mainly Long Lake but excludes acquisition of additional 15% in Long Lake project and joint venture lands.
- 2 Marketing, Corporate and Other.

Elsewhere in Canada, we increased our proved reserves by 3 mmbob (3 after royalties), but these additions were offset by negative economic revisions of 27 mmbob (22 after royalties) largely relating to our conventional heavy oil properties. These economic revisions were determined in accordance with current SEC rules that require the use of year-end commodity prices and operating costs even though we believe year-end operating costs do not reflect the current economic downturn and low commodity price environment.

### Yemen

Yemen remains a significant asset for us and continues to generate cash flow in excess of capital requirements. In 2008, we invested \$101 million and added 12 mmbob (9 after royalties) of proved reserves. We will continue to maximize the value of these assets over their remaining contract terms and expect 2009 annual production of between 40,000 and 45,000 boe/d, before royalties.

### Other Countries

Development of the Usan field, offshore West Africa, is underway with first production expected in 2012. In 2008, our capital investment at Usan on block OML-138 focused on detailed engineering, procurement and the initial fabrication of equipment. The development of Usan includes a FPSO with the ability to process 180,000 bbls/d and store up to two million barrels of oil. In 2009, we are scheduled to begin fabrication of the FPSO hull and topside facilities, begin development drilling, and complete detailed engineering and procurement. We are also evaluating plans for further exploration on this block. We have a 20% interest in exploration and development along with Total E&P Nigeria Limited (20% and Operator), Chevron Petroleum Nigeria Limited (30%) and Esso Exploration and Production Nigeria (Offshore East) Limited (30%).

In the fourth quarter of 2008, Nigerian authorities approved the acquisition of interests in offshore block OPL-223. We have a 20% funding interest and 18% beneficial interest in this block. Our partners are Total E&P Nigeria Limited (18% and Operator) ChevronTexaco Nigeria Deepwater F Limited (27%), Esso Exploration and Production (Upstream) Limited (27%) and Nigerian Petroleum Development Company Limited (10% carried interest). During 2009, we plan to advance evaluation of the prospects on this block.

Other international include our producing assets in Colombia and our exploration program in the Norwegian North Sea. In 2008, we invested approximately \$95 million in Norway, primarily to acquire seismic data.

### Syncrude

At Syncrude, we invested \$55 million in 2008 and added 8 mmbob (7 mmbob) of proved reserves. In 2009, we have one coker turnaround scheduled in the second quarter and expect annual production of between 20,000 and 25,000 bbls/d before royalties.

### Chemicals

Higher expenditures in 2008 related to the technology conversion project at our North Vancouver chlor-alkali plant. This was offset by lower expenditures related to the expansion of our Brandon sodium chlorate plant, which was completed in early 2008.

## FINANCIAL RESULTS

### Year-to-Year Change in Net Income

<i>(Cdn\$ millions)</i>	2008 vs 2007	2007 vs 2006
<b>Net Income for 2007 and 2006</b>	<b>1,086</b>	<b>601</b>
Favourable (unfavourable) variances: <sup>1</sup>		
Production Volumes, After Royalties		
Crude Oil	40	1,354
Natural Gas	(22)	(17)
Change in Crude Oil Inventory	13	22
Total Volume Variance	31	1,359
Realized Commodity Prices		
Crude Oil	1,495	308
Natural Gas	119	(24)
Total Price Variance	1,614	284
Operating Expense		
Conventional Oil & Gas	(49)	(178)
Syncrude	(72)	(21)
Total Operating Expense Variance	(121)	(199)
Depreciation, Depletion, Amortization and Impairment		
Oil & Gas and Syncrude	(228)	(636)
Other	(19)	(7)
Total DD&A	(247)	(643)
Exploration Expense	(76)	36
Net Energy Marketing Revenue	(424)	(373)
Chemicals Contribution	(76)	27
General and Administrative Expense	117	181
Interest Expense	74	(115)
Current Income Taxes	(425)	(66)
Future Income Taxes	(240)	(43)
Other		
Block 51 Settlement	–	151
Business Interruption Insurance Proceeds	–	(154)
Increase (Decrease) in Fair Value of Crude Oil Put Options	246	(32)
Other	156	72
<b>Net Income for 2008 and 2007</b>	<b>1,715</b>	<b>1,086</b>

<sup>1</sup> All amounts are presented before provision for income taxes.

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

## OIL & GAS AND SYNCRUDE

### Production

	2008		2007		2006	
	Before Royalties <sup>1</sup>	After Royalties	Before Royalties <sup>1</sup>	After Royalties	Before Royalties <sup>1</sup>	After Royalties
<b>Oil and Liquids</b> (mmbbls/d)						
United Kingdom	99.7	99.7	81.2	81.2	16.9	16.9
Yemen	56.6	30.6	71.6	39.8	92.9	51.8
Canada	16.2	12.3	17.1	13.4	20.0	15.8
United States	9.3	8.1	16.4	14.5	17.0	15.0
Other Countries	5.8	5.3	6.2	5.7	6.3	5.7
Long Lake Bitumen <sup>2</sup>	3.9	3.9	–	–	–	–
<b>Syncrude</b> (mmbbls/d) <sup>3</sup>	20.9	18.2	22.1	18.8	18.7	16.9
	212.4	178.1	214.6	173.4	171.8	122.1
<b>Natural Gas</b> (mmcf/d)						
United Kingdom	18	18	16	16	20	20
Canada	131	109	118	98	108	91
United States	78	66	101	86	111	94
	227	193	235	200	239	205
<b>Total</b> (mboe/d)	<b>250</b>	<b>210</b>	<b>254</b>	<b>207</b>	<b>212</b>	<b>156</b>

<sup>1</sup> We have presented production volumes before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.

<sup>2</sup> Pre-operating revenues and costs associated with Long Lake bitumen are capitalized as development costs until we reach commercial operations.

<sup>3</sup> Considered a mining operation for US reporting purposes.

### 2008 vs 2007—Higher net production increased income by \$31 million

Production after royalties in 2008 was slightly higher than 2007. At Buzzard, a full year of production offset declines at our maturing Yemen fields and hurricane interruptions in the US Gulf of Mexico. At Long Lake, increasing bitumen production contributed 3,900 boe/d to our 2008 volumes.

The following table summarizes our production changes year over year:

(mboe/d)	Before Royalties	After Royalties
<b>2007 Production</b>	<b>254</b>	<b>207</b>
<b>Production Changes</b>		
United Kingdom	19	19
Yemen	(15)	(9)
United States	(11)	(10)
Long Lake Bitumen	4	4
Other	(1)	(1)
<b>2008 Production</b>	<b>250</b>	<b>210</b>

Fourth quarter production averaged 230,000 boe/d (198,000 after royalties), down 16,000 boe/d from the prior quarter and 11,000 boe/d from the fourth quarter of 2007. Shut-in production in the Gulf of Mexico was the primary cause for the shortfall as US rates averaged 9,000 boe/d during the fourth quarter. The US was producing approximately 30,000 boe/d prior to the hurricanes. These shortfalls were partially offset by production at Long Lake where we averaged 6,500 boe/d for the quarter.

In 2009, we expect production to grow approximately 5% to 10% compared to 2008 and range between 255,000 and 270,000 boe/d before royalties. On an after-royalties basis, we expect production to grow 7% to 14% and range between 225,000 and 240,000 boe/d, reflecting growth in the UK North Sea and at Long Lake where royalties are low. Increases are expected to come from Ettrick in the UK North Sea, Longhorn in the US Gulf of Mexico and the Long Lake Project as bitumen rates increase.

Production volumes discussed in this section represent our working interest before royalties.

### United Kingdom

UK production for the year averaged 102,700 boe/d, 22% higher than 2007. This increase was primarily the result of a full year's high-margin, royalty-free Buzzard production, which averaged 88,200 boe/d. The Buzzard platform operated above expectations with minimal downtime. We are pursuing debottlenecking opportunities to increase processing capacity on the platform and export facilities.

Construction of the fourth platform at Buzzard started during the year. This platform will include production sweetening facilities designed to handle higher levels of hydrogen sulphide previously identified in the reservoir. The platform is expected to be in service in 2010 at a projected cost of between US\$350 million and US\$400 million, net to us.

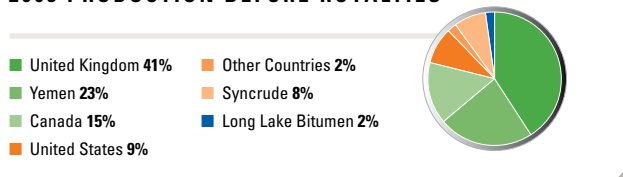
At Scott/Telford, higher than expected natural declines, combined with increased downtime for maintenance, reduced production by 36% to 10,500 boe/d. Maintenance on the Scott platform focused on resolving ongoing power supply issues. Downtime was also associated with platform and subsea workovers completed during the year. We recently started an infill drilling program at Scott to minimize the natural declines.

In 2009, we plan to drill up to three development wells at Scott/Telford and we anticipate bringing production on stream at Etrick in the next few months. We expect production from the North Sea to average between 100,000 and 115,000 boe/d in 2009. Our expected production for 2009 takes into account expected downtime.

### Yemen

In 2008, production from our Masila field declined 19% compared to last year and averaged 45,900 boe/d. This decline is consistent with our expectations as the field matures. We are targeting select infill development drilling opportunities due to the maturity of the field. During the year, we drilled 20 development wells and two sidetrack wells as we concentrate our drilling program on maximizing reserve recoveries and economic returns, prior to the 2011 expiry of our contract. In 2009, we plan to drill up to 35 development wells.

#### 2008 PRODUCTION BEFORE ROYALTIES



Production at our East Al Hajr field on Block 51 averaged 10,700 boe/d for 2008 and reflects natural declines and drilling fewer development wells. We drilled six development wells and one exploration well this year and plan to drill up to five development wells in 2009. We expect our share of Yemen production to average between 40,000 and 45,000 boe/d in 2009.

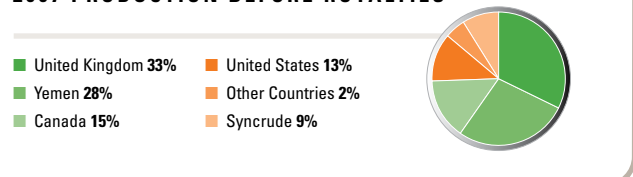
### Canada

Production in Canada (excluding oil sands) increased 3% in 2008, primarily as a result of increasing CBM volumes, offset by a decline in heavy oil production. CBM production increased 65% to average 43 mmcf/d during the year as we brought additional wells and facilities on stream and as existing wells in our Fort Assiniboine development inclined as they de-watered. Production from our heavy oil properties fell 7% in 2008. A successful capital investment program slowed declines in our maturing fields. Our natural gas production in the Medicine Hat region and at Balzac was comparable with the previous year.

Bitumen production at Long Lake averaged 3,900 boe/d (net to us) during 2008. We continued to inject steam into the reservoir and resolved a number of start-up issues with the SAGD operations during the year. The upgrader began producing premium synthetic crude oil in January 2009. The project is upgrading bitumen from our SAGD production and third-party bitumen purchases, and is currently producing between 10,000 and 15,000 boe/d of premium synthetic crude (between 6,300 and 9,750 net to us). Our SAGD operations and the upgrader start up were impacted by normal start-up challenges and extraordinarily cold weather. As a result, bitumen production averaged 13,200 boe/d for the fourth quarter (6,600 net to us), although rates are back up to 20,000 boe/d (13,000 net to us) in late January 2009. In early 2009, we increased our interest in the Long Lake Project from 50% to 65%.

In 2009, we expect our share of production from Canada to average between 35,000 and 40,000 boe/d and bitumen SAGD production at Long Lake is expected to average between 20,000 and 25,000 boe/d (net to us).

#### 2007 PRODUCTION BEFORE ROYALTIES



### *United States*

Our US production fell 33%, or about 11,000 boe/d from 2007, as hurricanes in the Gulf of Mexico temporarily shut-in production in the region. Prior to Hurricanes Gustav and Ike, we were producing approximately 30,000 boe/d. Production was reduced to 6,000 boe/d immediately after the hurricanes. Our properties at Gunnison, West Cameron and Eugene Island came back on stream during the fourth quarter and we exited the year producing approximately 12,000 boe/d. Production at Aspen recommenced at the end of January 2009. Wrigley remains shut in as third-party facilities have not yet been fully repaired. This work is ongoing and we expect production will be restored to pre-hurricane rates in the first quarter of 2009. Our Green Canyon 6, 50 and 137 deep-water fields remain shut in following the destruction of the third-party processing platform. We are currently evaluating production options for these fields.

Prior to the hurricanes, Aspen was producing 5,000 boe/d, down 50% from 2007. The decline is a result of: (i) natural decline rates; (ii) increased downtime due to third-party facility maintenance; and (iii) third-party limitations on handling higher water volumes. Production was curtailed while increased water handling equipment was installed on the Shell-operated platform. We expect production rates from Aspen to increase slightly in 2009 as the platform can now handle additional amounts of water from the field.

Gunnison suffered only minor damage during the storms and was back on stream in October. Pre-hurricane Gunnison production averaged 5,000 boe/d, down 26% from 2007. Lower volumes due to natural declines and ongoing maintenance were partially offset by an additional development well drilled during the year and successful recompletions.

Our shelf production decreased 3,800 boe/d as a result of natural declines, approximately 27% below 2007 rates. During the year, we completed several successful recompletions and workovers to enhance performance; however, we are minimizing the capital invested in our mature shelf assets.

In 2009, we expect production from the Gulf of Mexico to average between 20,000 and 25,000 boe/d.

### *Other Countries*

Production from Guando in Colombia decreased marginally to 5,800 boe/d in 2008. The infill drilling program was completed in the second quarter of 2008; however, the full benefit of this program was not realized as landslides in April shut-in six wells. Most of these wells are back on stream. Under the terms of our license, our interest in the field will decrease by half to 10% once the field has produced 60 million barrels, which we expect to occur mid 2009. We expect our share of production to average between 3,000 and 5,000 boe/d in 2009.

### *Syncrude*

Syncrude production decreased 5% to average 21,000 boe/d during the year. Production has been impacted by several factors during the year including: (i) two planned coker turnarounds and other maintenance; (ii) shut down of the sulphur plant for maintenance; (iii) reduction in shipments of synthetic crude from outages in the Pembina pipeline; and (iv) shortage of bitumen supply as a result of production challenges in the mines, which have since been resolved. In 2009, we expect production to average between 20,000 and 25,000 boe/d.

In late 2008, the Alberta government and the Syncrude owners reached an agreement to amend their existing royalty agreement. The new royalty agreement is expected to increase our after-royalty production volumes.

### **2007 vs 2006—Higher production increased net income by \$1,359 million**

Production before royalties increased 20% from 2006 (33% after royalties). This increase reflected the start up of Buzzard production in early 2007, partially offset by declines in our maturing Yemen fields. The addition of high-margin, royalty-free Buzzard volumes increased North Sea production by 64,000 boe/d (net to us). Buzzard production ramped up to peak production in 2007 and produced above design rates during the year. Production in Canada was comparable with 2006 rates as we continued to offset mature base declines with strategic capital investment.

In the Gulf of Mexico, deep-water production from Aspen and Gunnison was down from 2006 from natural field declines. The Wrigley development came on line mid 2007 but rates were lower due to third-party production restrictions. At Syncrude, production was 18% higher than 2006 as the Stage 3 expansion contributed a full year of production.

## Commodity Prices

	2008	2007	2006
<b>Crude Oil</b>			
West Texas Intermediate (WTI) (US\$/bbl)	99.65	72.31	66.22
Benchmark Differentials <sup>1</sup> (US\$/bbl)			
Heavy Oil	20.27	23.44	21.79
Dated Brent	2.66	(0.21)	1.08
Mars	6.21	5.67	7.34
Masila	4.31	0.50	3.00
Realized Prices from Producing Assets (Cdn\$/bbl)			
United Kingdom	96.23	76.30	71.19
Yemen	99.87	76.29	71.57
Canada	74.51	44.07	42.79
United States	104.94	69.83	65.80
Other Countries	98.98	71.29	66.09
Syn crude	105.47	79.76	72.32
Corporate Average (Cdn\$/bbl)	96.92	73.43	67.50
<b>Natural Gas</b>			
New York Mercantile Exchange (US\$/mmbtu)	8.90	7.12	6.99
AECO (Cdn\$/mcf)	7.71	6.26	6.62
Realized Prices from Producing Assets (Cdn\$/mcf)			
United Kingdom	6.78	4.71	7.43
Canada	7.73	6.32	6.49
United States	10.07	7.80	7.86
Corporate Average (Cdn\$/mcf)	8.44	6.81	7.18
<b>Nexen's Average Realized Oil and Gas Price (Cdn\$/boe)</b>	<b>89.78</b>	<b>68.46</b>	<b>62.92</b>
Average Foreign Exchange Rate—Canadian to US Dollar	0.9381	0.9304	0.8818

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

### 2008 vs 2007—Higher realized prices increased net income \$1,614 million

In 2008, commodity prices reached record highs but declined significantly in the fourth quarter. WTI averaged US\$99.65/bbl for the year, 38% higher than 2007, while Dated Brent increased 34% over the same period. Our average realized crude oil price increased 32% from \$73.43/bbl to \$96.92/bbl. During the year, NYMEX gas price increased 25% and AECO increased 23%, averaging US\$8.90/mmbtu and \$7.71/mcf, respectively. During the same period, our corporate average realized gas price increased 24% to \$8.44/mcf, as our gas sales are primarily based off of NYMEX and AECO prices. Compared to 2007, the US dollar weakened relative to the Canadian dollar. As a result, our realized crude oil and natural gas price decreased by approximately \$0.80/bbl and \$0.07/mcf, respectively and our net sales were lower by approximately \$56 million.

Commodity prices fell dramatically during the fourth quarter as the global economic crisis reduced demand for oil and gas. WTI averaged US\$58.73/bbl for the quarter, down 50% from the previous quarter and 35% from the same period last year. Our

realized average oil price was \$59.90/bbl in the fourth quarter compared to \$115.56/bbl in the third quarter. NYMEX gas prices also fell during the fourth quarter to average US\$6.41/mcf.

### Crude Oil Reference Prices

Crude oil prices were volatile in 2008, reaching an all-time high of US\$147.27/bbl in mid-July, before declining to close the year at US\$44.60/bbl. The increase during the first half of the year was driven by the weakened US dollar and global political tensions as well as by traditional supply and demand fundamentals. The main driver of falling prices in the second half of the year was a weak global economy following the worldwide financial crisis, which dramatically reduced demand for all commodities.

The US dollar weakened during the first half of 2008 and fell to an all-time low against the Euro as the financial markets reacted to the threat of a US recession and the global credit crisis. Investors re-directed their investments into commodity markets to hedge against the weak dollar and inflation, which contributed to the increase in oil prices.

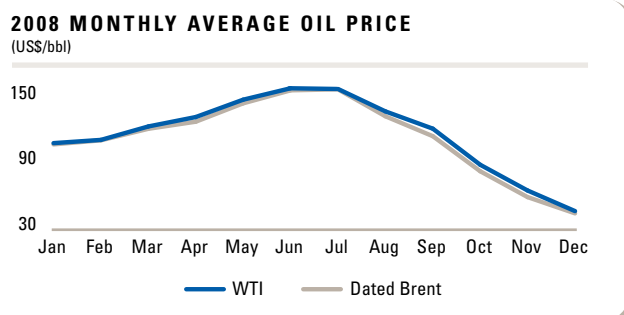
In the second half of the year, the market's focus moved from concerns about adequate future supply to fears of declining demand. Geopolitical events impacting global supply had minimal impact on prices as these events were overshadowed by the weak global economy and declining oil demand. Near-term oil market fundamentals weakened and year-end crude oil inventories were high relative to the last five years.

### Crude Oil Differentials

In Canada, heavy crude oil differentials averaged US\$20.27/bbl (20% of WTI) for the year, compared to US\$23.44/bbl (32% of WTI) in 2007. Demand for heavy oil increased when BP's Whiting refinery came back online in the first quarter of 2008. Declining Venezuelan and Mexican heavy oil production, a slower ramp up of industry oil sands production, higher demand in the summer asphalt season and the desire to run heavier crude in a low refinery margin environment all contributed to narrower differentials earlier in the year. As WTI prices declined in the fall, the heavy differential widened relative to WTI. The onset of winter and seasonally lower demand contributed to the widening differential.

The Brent/WTI differential weakened during 2008, with Brent trading at a discount of US\$2.66/bbl compared to a premium of US\$0.21/bbl in 2007. The WTI/Brent price differential was volatile in 2008, but WTI traded at a premium to Brent for most of the year. Higher than expected freight costs and storm displacements during the hurricane season increased the WTI premium over Brent, which peaked in November at over US\$5.00/bbl. Since then, weak demand and higher Cushing inventories have depressed WTI prices and the differential narrowed late in the year.

The US Gulf Coast Mars differential widened slightly, averaging US\$6.21/bbl in 2008 compared to US\$5.67/bbl last year. Overall, the differential remained historically high during the year. Higher WTI inventories at Cushing in December caused the WTI/Mars differential to narrow towards the end of the year.



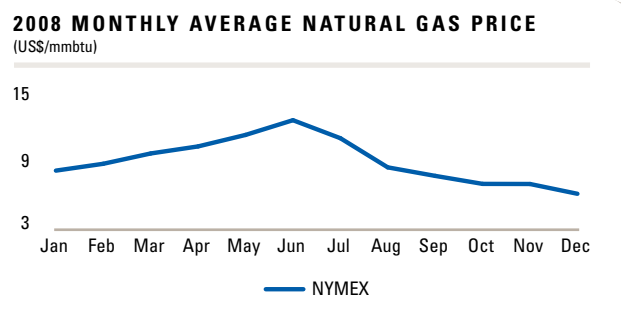
The Yemen Masila differential widened substantially relative to WTI during 2008, averaging US\$4.31/bbl compared to US\$0.50/bbl last year. Yemen Masila traded at a discount to WTI in 2008, reflecting the impact of stronger WTI versus Brent pricing as Masila crude is typically priced off Brent.

### Natural Gas Reference Prices

NYMEX natural gas prices averaged US\$8.90/mmbtu in 2008, 25% higher than 2007. Higher crude oil prices, low LNG imports and lower storage levels at the end of the 2007/2008 winter withdrawal season provided support for prices in the first half of the year. Since mid-year, a weak US economy and significant supply increases in unconventional production increased inventory levels and reduced prices. Declining crude oil prices and continuing weakness in the global economy could lead to more LNG cargoes coming to North America during 2009, adding downward pressure on natural gas prices. A colder than expected 2008/2009 winter weather provided some offset to the bearish factors impacting gas prices.

### 2007 vs 2006—Higher realized prices increased net income \$284 million

Average WTI and Dated Brent in US dollars were 9% and 11% higher, respectively, from the prior year, and our average realized crude oil price increased 9% to \$73.43/bbl. Our higher average realized price reflects the change in production mix with the addition of new high-quality Buzzard production. This change helped to offset the impact of the weaker US dollar on our Canadian dollar realized prices. Our realized natural gas price fell 5% from 2006 as a result of the stronger Canadian dollar, despite NYMEX increasing 2% in the same period. The weaker US dollar reduced net sales by approximately \$225 million, and reduced our realized crude oil and natural gas prices by approximately \$3.20/bbl and \$0.30/mcf, respectively, as compared to 2006.



## Operating Expenses

(Cdn\$/boe)	2008		2007		2006	
	Before Royalties <sup>1</sup>	After Royalties	Before Royalties <sup>1</sup>	After Royalties	Before Royalties <sup>1</sup>	After Royalties
<b>Conventional Oil and Gas</b>						
United Kingdom	6.75	6.75	6.94	6.94	11.28	11.28
Yemen	8.51	15.88	6.56	12.00	4.45	8.11
Canada	13.12	16.38	12.91	15.93	10.31	12.73
United States	11.57	13.48	8.43	9.69	8.17	9.45
Other Countries	4.52	4.91	3.45	3.76	2.87	3.13
Average Conventional	8.68	10.40	7.89	9.75	6.95	9.69
<b>Synthetic Crude Oil</b>						
Syncrude	36.53	42.04	25.80	30.32	27.53	30.43
<b>Average Oil and Gas</b>	<b>11.04</b>	<b>13.18</b>	<b>9.45</b>	<b>11.63</b>	<b>8.77</b>	<b>11.96</b>

<sup>1</sup> 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.

### 2008 vs 2007—Higher operating expenses decreased net income by \$121 million

Overall, operating costs increased 14% from 2007, primarily due to Buzzard being on-stream for the full year and higher expenditures at Syncrude. Our production mix continues to change as additional Buzzard volumes are offset by lower volumes in Yemen and the US Gulf of Mexico. Changes in our production profile reduced our corporate average by \$0.35/boe, as Buzzard has lower operating costs per barrel.

In the UK North Sea, operating costs increased 19%. The increase is attributable to a full year's production at Buzzard, compared to 2007 when we were ramping up production. In addition, transportation costs increased from higher volumes and increased tariff charges. Elsewhere in the UK North Sea, operating costs increased while production declined, increasing our corporate average by \$0.45/boe. The majority of the cost increase is due to platform maintenance at Scott/Telford, including: (i) additional diesel costs for turbine repairs; (ii) maintenance on our water injection and power generation facilities; and (iii) subsea maintenance.

In Yemen, Masila and Block 51 increased our corporate average by \$0.32/boe and \$0.21/boe, respectively, as a result of lower production rates. Our operating costs are focused on service rig activity and maintenance programs for existing wells. In the US Gulf of Mexico, operating costs were 8% lower than 2007; however, lower production as a result of the hurricanes increased the average unit cost by \$0.30/boe.

Operating costs in Canada were marginally higher than last year. Costs in our heavy oil operations increased as a result of higher salaries, utilities and trucking costs. While CBM costs were slightly higher as the number of producing wells increased, the

incremental volumes reduced our average cost per barrel. At our natural gas properties, a combination of increased downhole activity and surface maintenance resulted in higher operating costs. These increases were offset by lower costs at our Balzac gas plant, which had a turnaround in the previous year.

Syncrude operating costs were \$72 million or 35% higher than the prior year and increased our corporate average by \$0.91/boe. A number of factors contributed to the higher operating costs including: (i) higher contracting costs to increase the mineable ore inventory for bitumen supply; (ii) purchasing additional third-party bitumen to upgrade; (iii) higher natural gas prices in the first half of 2008; and (iv) unscheduled and extended maintenance. We expect Syncrude operating costs will decrease slightly in 2009.

US-dollar denominated operating costs were lower when translated to Canadian dollars as a result of the weaker US dollar for the majority of the year. This decreased our corporate average by \$0.23/boe for 2008.

### 2007 vs 2006—Higher operating expenses decreased net income by \$199 million

Our operating costs increased \$199 million from 2006 primarily as a result of Buzzard coming on stream in early 2007 and higher Syncrude production. Our production mix also changed from last year as a result of this production, altering our average unit cost. Operating costs at Buzzard are lower than our corporate average, reducing our corporate average by \$1.58/boe. However, the higher-cost Syncrude barrels increased our corporate average by \$0.74/boe.

At Masila in Yemen, operating costs increased with higher service rig activity and maintenance programs. The higher costs and lower production increased our corporate average by \$0.57/boe. Similarly at Block 51, our operating expenditures were higher as additional service rig activity and higher water handling, fuel and equipment costs increased operating expenditures. The higher costs increased our corporate average \$0.37/boe.

Canadian production increased our corporate average \$0.50/boe during the year as a result of industry cost pressures, the extended Balzac turnaround and lower production. Our heavy oil properties have higher unit operating costs as many of the costs are fixed in nature and heavy oil production is declining. Operating costs have also increased with additional CBM wells coming on-stream at Fort Assiniboine. Unit operating costs are initially higher as we de-water the wells to stimulate gas production.

In the Gulf of Mexico, while total operating costs remained consistent year over year, lower production increased our corporate average by \$0.18/boe. During 2007, industry pressures increased costs and we performed additional downhole and

surface maintenance activity to maintain production. However, these costs had minimal impact on our corporate average when compared to last year as our 2006 costs included extended maintenance and turnaround activity at Eugene Island on the shelf.

In the UK North Sea, our Scott/Telford costs increased our corporate average by \$0.33/boe. During the year, our total operating expenditures increased as we performed maintenance and work overs on the platform and producing wells, including repairing turbines and improving water injection facilities.

Lower Syncrude operating costs reduced our corporate average by \$0.16/boe, and were 6% lower than 2006 as the impact of the higher production from the expansion completed in 2006 was only partially offset by increased maintenance costs. In 2007, maintenance and turnarounds on the Coker 8-3 and the LC Finer interrupted production and increased operating costs.

US-dollar denominated operating costs were lower when translated into Canadian dollars, reducing our corporate average \$0.26/boe.

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

(Cdn\$/boe)	2008		2007		2006	
	Before Royalties <sup>1</sup>	After Royalties	Before Royalties <sup>1</sup>	After Royalties	Before Royalties <sup>1</sup>	After Royalties
<b>Conventional Oil and Gas<sup>2</sup></b>						
United Kingdom	17.72	17.72	19.59	19.59	30.22	30.22
Yemen	7.75	14.45	8.15	14.92	9.67	17.61
Canada	14.99	18.71	12.46	15.37	11.22	13.84
United States	27.46	31.97	22.64	26.03	16.28	18.84
Other Countries	7.90	8.58	3.68	4.06	4.30	4.69
Average Conventional	15.48	18.54	14.94	18.47	13.12	18.30
<b>Synthetic Crude Oil</b>						
Syncrude	6.39	7.35	6.59	7.74	4.81	5.32
<b>Average Oil and Gas</b>	<b>14.71</b>	<b>17.56</b>	<b>14.21</b>	<b>17.49</b>	<b>12.38</b>	<b>16.88</b>

<sup>1</sup> 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.

<sup>2</sup> DD&A per boe excludes the impairment charges described in Note 4 of our Consolidated Financial Statements.

#### 2008 vs 2007—Higher oil and gas and Syncrude DD&A decreased net income by \$228 million

During the fourth quarter, we recorded non-cash impairment charges of \$568 million primarily relating to some properties in the UK North Sea and the Gulf of Mexico. In the North Sea, we recognized an impairment charge of \$318 million relating to our Selkirk and Ettrick properties. At Selkirk, we expensed \$62 million of allocated acquisition costs as we have no firm development plans. At Ettrick, the impairment charge largely reflects higher costs and lower reserve estimates. In the Gulf of Mexico, our impairment charge relates to four shelf properties (\$143 million) and our Green Canyon 6 deep-water property (\$107 million). The shelf properties that were impaired are late-life, mature assets that are sensitive to near-term commodity prices. At Green Canyon 6, the impairment expense reflects higher costs after Hurricane Ike destroyed a third-party production platform in the third quarter of 2008. This has resulted in unexpected costs to construct new production facilities and, following an evaluation of options, we expect to have production back on stream in late 2010.

In the UK, our DD&A expense increased 14% over last year as a result of additional production from Buzzard. The impact of higher production was offset by a lower DD&A rate at Buzzard with the addition of new reserves at the beginning of 2008. The lower depletion rate at Buzzard decreased our corporate average rate by \$0.74/boe. Elsewhere in the UK, our depletion rate increased at our mature Scott/Telford and smaller Farragon fields, increasing our corporate average by \$0.47/boe.

In the Gulf of Mexico, reserve revisions at the end of 2007 resulted in higher depletion rates in 2008 and increased our corporate average unit cost by \$0.59/boe.

Depletion of our Canadian assets increased our corporate average rate by \$0.38/boe and is primarily due to our CBM projects in central Alberta. During the year, we invested capital in new wells and facilities. A difference exists between the timing of capital expenditures and the recognition of the reserves. This delay results in high initial depletion rates for our CBM projects. As additional reserves can be recognized, depletion rates should decrease.

In Colombia, our depletion rate doubled from 2007, a result of increased capital costs and lower reserve estimates. This increased our corporate average rate by \$0.10/boe.

The stronger Canadian dollar relative to the US dollar decreased our corporate average DD&A rate by \$0.45/boe as our US and international depletion is denominated in US dollars.

### 2007 vs 2006—Higher oil and gas and Syncrude DD&A decreased net income by \$636 million

In 2007, our DD&A expense includes \$366 million (\$3.96/boe) of impairment expense primarily related to our Aspen, Vermilion 320/340 and West Cameron 170 properties in the Gulf of Mexico as we had poor results from capital investments and lower reserve estimates. At Aspen, disappointing results from our

investment in development drilling resulted in negative reserve revisions. While we were encouraged by well log data indicating thick pay zones, well deliverability rates could not be sustained. This likely indicates barriers within this section of the reservoir. At Vermilion 320/340 and West Cameron 170, negative reserve revisions primarily related to gas properties, where unsatisfactory investment results, production performance, revised mapping and higher projected operating costs resulted in a downward revision to reserves estimates. The carrying values of these properties were reduced to their estimated fair value.

Production from Buzzard increased our corporate average unit DD&A rate by \$1.44/boe. Buzzard costs were higher than our corporate average as they include acquisition and project completion costs. We recognized additional proved reserves at the end of 2006 for our other UK assets, which lowered the corporate average \$0.59/boe in 2007.

A reduced capital program and slower recovery of capital costs paid on the Yemen government's behalf decreased our corporate average DD&A rate by \$0.15/boe.

Depletion of our Canadian assets increased our corporate average by \$0.24/boe reflecting the timing of reserve bookings from our CBM projects in central Alberta, and land acquisitions in 2006. In the Gulf of Mexico, unsuccessful development drilling at Aspen and on the shelf increased our capital base, increasing our corporate average rate by \$1.29/boe.

Syncrude DD&A includes costs to develop the Stage 3 expansion that came on stream in mid 2006, which increased our corporate average by \$0.21/boe.

The strong Canadian dollar relative to the US dollar decreased our corporate average DD&A rate by \$0.53/boe as our US and international depletion is denominated in US dollars.

### Exploration Expense

<i>(Cdn\$ millions)</i>	2008	2007	2006
Seismic	137	123	128
Unsuccessful Drilling	203	126	169
Other	62	77	65
<b>Total Exploration Expense</b>	<b>402</b>	<b>326</b>	<b>362</b>
New Growth Exploration	582	573	491
Geological and Geophysical Costs	137	123	128
<b>Total Exploration Expenditures</b>	<b>719</b>	<b>696</b>	<b>619</b>
Exploration Expense as a % of Exploration Expenditures	56%	47%	58%

### 2008 vs 2007—Higher exploration expense reduced net income by \$76 million

Our total exploration expenditures increased \$23 million over last year. We focused our investments on exploratory drilling in the US Gulf of Mexico, UK North Sea and CBM in Canada, and on acquiring seismic data in Norway. Exploration expense increased 23% over the same period due to higher seismic data acquisitions and unsuccessful exploration wells.

In the Gulf of Mexico, we drilled two successful deep-water exploration wells early in 2008 at Green Canyon 448 and Mississippi Canyon 72. Elsewhere in the deep water, we drilled two unsuccessful wells. At Fredericksburg, we drilled to a depth of 24,560 feet but failed to encounter commercial hydrocarbons. This well was subsequently abandoned and \$24 million in exploration costs were written off. Our unsuccessful exploration well at Sapphire resulted in a \$28 million expense. We are currently drilling our Cote de Mer prospect and results are expected mid 2009.

In the UK North Sea, we had successes at Blackbird, Pink, Bugle and Rochelle. Blackbird is located 6 km south of Ettrick and production could be tied to the Ettrick FPSO, following additional appraisal drilling and development evaluation. At Pink, we drilled a successful exploration well and sidetrack, and we are currently evaluating development options, including co-development with our previous Golden Eagle discovery. We recently completed drilling a successful appraisal well at Rochelle where we have a 44% non-operated interest. Rochelle is located approximately 20 km south of the Scott/Telford fields. During the year, we drilled a dry hole at Full Moon which cost \$16 million and we expensed \$32 million of drilling costs for our Selkirk prospect which we do not plan to develop at this time.

In Canada, we expensed \$67 million for unsuccessful CBM exploration in Alberta. The costs relate to our CBM exploration activities in central Alberta where we have no future development plans. We continue to investigate the CBM potential of other areas.

During 2008, seismic data acquisition costs were 11% higher than 2007. Norway seismic acquisitions increased 47% during the year when we obtained data on newly acquired blocks in the Norwegian North Sea. In the US Gulf of Mexico, our seismic investment decreased from last year as we are focusing on analyzing the seismic data acquired over the past couple of years. Elsewhere, we acquired seismic data in the UK North Sea, Nigeria and Colombia.

### 2007 vs 2006—Lower exploration expense increased net income by \$36 million

We invested almost \$700 million in exploration-oriented activities in 2007, primarily related to drilling in the Gulf of Mexico, UK North Sea and CBM in Canada, and acquiring seismic data in the Gulf of Mexico and Norway. In addition, we acquired material land positions in the Gulf of Mexico, and in northeast British Columbia related to an emerging Devonian shale gas play in the Horn River basin.

Exploration expense decreased \$43 million or 25% from 2006 as a result of fewer unsuccessful exploration wells. In the Gulf of Mexico, we incurred dry hole costs of \$59 million as compared to \$135 million in 2006; however, this decrease was partially offset by higher unsuccessful well costs in the UK North Sea, Colombia and Canada.

In the deep-water Gulf of Mexico, we drilled a successful appraisal well at Longhorn and evaluated resource estimates. Development of Longhorn is underway and production is expected to begin in 2009. Also in the deep water, our Vicksburg prospect was drilled to a depth of 25,400 feet and encountered hydrocarbons. Core was recovered from the well and studies are underway to assess the potential productivity. Our unsuccessful drilling results in the Gulf of Mexico were primarily on the shelf where we expensed \$35 million for dry holes. In the deep water, we drilled a sidetrack at Aspen targeting two zones in deeper sands; however, results from the lowest zone were unsuccessful and we expensed \$20 million for a portion of the drilling costs of the well.

In the UK North Sea, we had several exploration successes. We followed up our successful Golden Eagle well by drilling a sidetrack to appraise the accumulation. Our 2007 dry hole costs in the UK North Sea were \$39 million compared to \$21 million in 2006. The \$15 million Guinea well was completed in the first quarter; however, the target reservoir was water bearing and the well was abandoned. Exploration wells at Stag and Dee were plugged and abandoned, resulting in \$12 million and \$8 million, respectively, in expensed costs.

In Colombia, we expensed \$11 million related to the unsuccessful Guaini-1 and Atalea-1 exploratory wells. In Canada, we expensed costs associated with unsuccessful CBM activities at Provost, Kakwa and Sullivan Lake. Seismic data costs of \$123 million were comparable with 2006. The Gulf of Mexico and Norway accounted for 74% of the seismic expenditures, as we consider these areas to have significant exploration potential.

## OIL & GAS AND SYNCRUDE NETBACKS

Netbacks are the cash margins, before general and administrative expenses, we receive for every equivalent barrel sold. The following table lists the sales prices, per-unit costs and netbacks for our producing assets, calculated using our working interest production before and after royalties. A combination of strong realized prices and new high-margin production from Buzzard increased our cash netback by 40% from last year (36% after royalties).

### Before Royalties

	2008						
(\$/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	99.87	58.34	79.02	94.45	98.98	105.47	89.78
Royalties and Other	(46.94)	(12.25)	(11.03)	–	(7.88)	(15.11)	(15.06)
Operating Expenses	(8.51)	(13.12)	(11.57)	(6.75)	(4.52)	(36.53)	(11.04)
In-country Taxes <sup>1</sup>	(13.31)	–	–	–	–	–	(3.04)
<b>Cash Netback</b>	<b>31.11</b>	<b>32.97</b>	<b>56.42</b>	<b>87.70</b>	<b>86.58</b>	<b>53.83</b>	<b>60.64</b>

	2007						
(\$/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	76.29	40.79	58.16	74.79	71.29	79.76	68.46
Royalties and Other	(34.69)	(7.81)	(7.45)	–	(5.90)	(12.02)	(13.10)
Operating Expenses	(6.56)	(12.91)	(8.43)	(6.94)	(3.45)	(25.80)	(9.45)
In-country Taxes <sup>1</sup>	(9.52)	–	–	–	–	–	(2.69)
<b>Cash Netback</b>	<b>25.52</b>	<b>20.07</b>	<b>42.28</b>	<b>67.85</b>	<b>61.94</b>	<b>41.94</b>	<b>43.22</b>

	2006						
(\$/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	71.57	40.98	56.12	66.81	66.09	72.32	62.92
Royalties and Other	(32.32)	(7.80)	(7.53)	–	(5.51)	(6.93)	(17.68)
Operating Expenses	(4.45)	(10.31)	(8.17)	(11.28)	(2.87)	(27.53)	(8.77)
In-country Taxes <sup>1</sup>	(8.45)	–	–	–	–	–	(3.72)
<b>Cash Netback</b>	<b>26.35</b>	<b>22.87</b>	<b>40.42</b>	<b>55.53</b>	<b>57.71</b>	<b>37.86</b>	<b>32.75</b>

### After Royalties

	2008						
(\$/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	99.87	58.34	79.02	94.45	98.98	105.47	89.78
Operating Expenses	(15.88)	(16.38)	(13.48)	(6.75)	(4.91)	(42.04)	(13.18)
In-country Taxes <sup>1</sup>	(24.83)	–	–	–	–	–	(3.63)
<b>Cash Netback</b>	<b>59.16</b>	<b>41.96</b>	<b>65.54</b>	<b>87.70</b>	<b>94.07</b>	<b>63.43</b>	<b>72.97</b>

	2007						
(\$/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	76.29	40.79	58.16	74.79	71.29	79.76	68.46
Operating Expenses	(12.00)	(15.93)	(9.69)	(6.94)	(3.76)	(30.32)	(11.63)
In-country Taxes <sup>1</sup>	(17.42)	–	–	–	–	–	(3.31)
<b>Cash Netback</b>	<b>46.87</b>	<b>24.86</b>	<b>48.47</b>	<b>67.85</b>	<b>67.53</b>	<b>49.44</b>	<b>53.52</b>

	2006						
(\$/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	71.57	40.98	56.12	66.81	66.09	72.32	62.92
Operating Expenses	(8.11)	(12.73)	(9.45)	(11.28)	(3.13)	(30.43)	(11.96)
In-country Taxes <sup>1</sup>	(15.40)	–	–	–	–	–	(5.07)
<b>Cash Netback</b>	<b>48.06</b>	<b>28.25</b>	<b>46.67</b>	<b>55.53</b>	<b>62.96</b>	<b>41.89</b>	<b>45.89</b>

<sup>1</sup> Comprises income taxes payable in Yemen that are included in the Government's share of profit oil.

## ENERGY MARKETING

<i>(Cdn\$ millions)</i>	<b>2008</b>	<b>2007</b>	<b>2006</b>
Physical Sales <sup>1</sup>	54,772	34,358	30,025
Physical Purchases <sup>1</sup>	(54,047)	(33,417)	(29,060)
Net Financial Transactions <sup>1</sup>	(142)	(61)	344
Change in Fair Market Value of Inventory <sup>1</sup>	(116)	79	–
<b>Marketing Revenue</b>	<b>467</b>	<b>959</b>	<b>1,309</b>
Transportation Expense	(751)	(806)	(789)
Other	27	14	20
<b>Net Marketing Revenue</b>	<b>(257)</b>	<b>167</b>	<b>540</b>
<b>Contribution to Net Marketing Revenue by Region:</b>			
North America	(284)	151	526
Asia	13	11	13
Europe	14	5	1
<b>Net Marketing Revenue</b>	<b>(257)</b>	<b>167</b>	<b>540</b>
Depreciation, Depletion, Amortization and Impairment	(19)	(13)	(12)
General and Administrative	(79)	(87)	(112)
Allowance for Doubtful Receivables	(54)	–	–
<b>Marketing Contribution to Income before Income Taxes</b>	<b>(409)</b>	<b>67</b>	<b>416</b>
<b>North America</b>			
<b>Natural Gas</b>			
Physical Sales Volumes <sup>2</sup> (bcf/d)	6.7	5.8	5.4
Transportation Capacity (bcf/d)	1.8	2.0	3.3
Storage Capacity <sup>3</sup> (bcf)	38	39	50
Financial Volumes (bcf/d)	16.8	21.9	19.8
<b>Crude Oil</b>			
Physical Sales Volumes <sup>2</sup> (mmbbls/d)	656	655	553
Storage Capacity (mmbbls)	2,578	2,734	1,749
Financial Volumes (mmbbls/d)	1,591	2,134	1,976
<b>Power</b>			
Physical Sales Volumes <sup>2</sup> (MW/d)	4,796	4,516	4,388
Generation Capacity (MW/hr)	87	87	87
<b>Asia</b>			
Physical Sales Volumes <sup>2</sup> (mmbbls/d)	182	183	152
Financial Volumes (mmbbls/d)	349	256	207
<b>Europe</b>			
Financial Volumes (mmbbls/d)	787	529	52
<b>Value-at-Risk</b>			
Year End <sup>4</sup>	25	26	26
High	40	38	33
Low	19	24	17
Average	30	30	23

<sup>1</sup> Marketing's physical sales, physical purchases, net financial transactions and changes in fair market value of inventory are reported net on the Consolidated Statement of Income as marketing and other.

<sup>2</sup> Excludes inter-segment transactions.

<sup>3</sup> Marketing's storage capacity reflects volumes contracted but not necessarily used.

<sup>4</sup> Value-at-Risk (VaR) was reduced subsequent to year end. At January 31, 2009, VaR was \$20 million.

### 2008 vs 2007—Reduced energy marketing net revenue decreased net income by \$424 million

The past year proved challenging for our energy marketing group as unprecedented market conditions impacted physical market fundamentals and the pricing relationships we successfully positioned ourselves to profit from historically. In the first half of the year, commodity markets were strong with crude oil prices hitting an all-time high and natural gas pricing near record levels. In the last half of the year, the trend reversed sharply as the US financial crisis intensified and spread globally, curtailing growth and demand for energy commodities.

While the global economic slowdown produced challenges for our business, we were most heavily impacted by the significant volatility in commodity markets as we were not positioned to take advantage of them. Instead, we were positioned to take advantage of normal physical fundamentals but these were overwhelmed by significant downward price movements, increased volatility and the economic slowdown. In mid-2008, we started exiting positions that did not support our physical marketing business and we were scaling back our trading activities in an orderly fashion to minimize losses on closing positions. This was a challenging process given the lack of liquidity in the market, fewer counterparties and deteriorating commodity prices that have eroded natural gas spreads.

The loss in North America was due to losses in our natural gas and NGLs businesses, which were partially offset by contributions from our crude oil and power businesses.

Losses in our natural gas business resulted largely from basis positions designed to take advantage of changing price relationships between locations, as well as financial positions designed to protect the value of our physical transportation capacity contracts. The losses we incurred in mid-2008 related to positions we had taken that were expected to benefit from strengthening natural gas prices in the US Rockies following the addition of new pipeline capacity in the region. Delays in the start-up of this pipeline worked against these positions and resulted in losses as we closed them out mid-year. This left us with trading positions that were expected to benefit from widening east-west location spreads later in the year driven by typical winter demand in eastern consuming gas markets. As we worked to reduce this trading exposure, we were faced with a rapidly deteriorating economic environment in which natural gas prices fell from highs of over US\$13.00/mmbtu in the summer to winter prices of approximately US\$6.00/mmbtu in December and US\$4.50/mmbtu in January 2009, a period

normally characterized by increasing prices. These falling natural gas prices compressed spreads causing losses in the third quarter and additional losses in the fourth quarter as the widening spreads we were positioned for did not materialize and spreads narrowed even further despite cold weather in the east due to demand destruction in the economy. We exited the last of these positions in January 2009.

We also recognized losses on financial positions, including basis, currency and futures contracts, used to hedge our physical transportation capacity contracts. The offsetting gains on our physical capacity contracts cannot be recognized in our results until they are used in the future.

Our marketing results also include losses from our NGL business in the fourth quarter. Over the years, we have been developing this business to take advantage of growing demand for green fuels, such as ethanol, denaturant and propane. The loss reflects declining margins for these products following substantial demand reduction caused by the current economic environment. We are in the process of exiting our ethanol and propane businesses and we expect to complete this by the end of the first quarter.

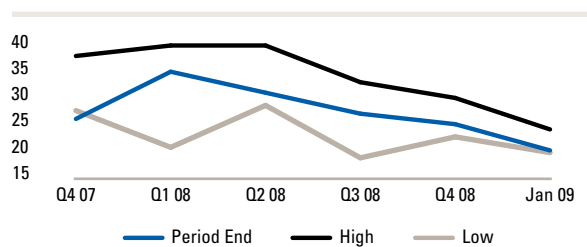
Our crude oil business was positioned to take advantage of daily volatility in both WTI and crude oil quality differentials. Profits were generated primarily by blending activities, by diverting crude oil to more attractive markets and by storing crude oil to capture higher future prices. Losses on financial strategies designed to protect the value of our future storage positions partially offset these gains. A portion of these losses will be recovered in the future when the offsetting gains on the physical positions are recognized.

Our European business has improved their results by focusing on a physical producer/marketer model. We added physical capacity contracts, both storage and transportation, in the UK and continental Europe. Our Asian business continued to generate solid profits by marketing our Masila barrels from Yemen.

We are realigning our energy marketing strategies and positions to better support our core physical business as a producer/marketer. We expect to focus on marketing and optimization which involves buying, selling and holding physical commodities, as well as the rights to physical transportation and storage assets. Holding physical assets allows us to extract value when events, particularly weather, cause a disconnect between markets or time periods. Despite recent losses, this business has contributed \$380 million of cash flow over the past five years.

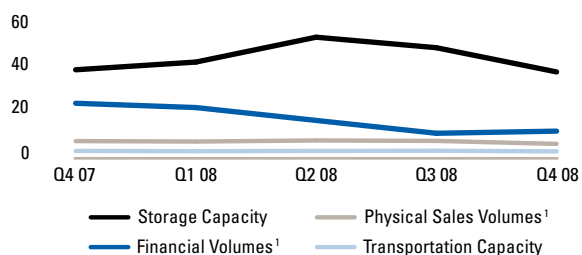
We have significantly reduced our financial trading levels in North America and continue to exit positions that do not support our renewed focus. The following graphs show the changes in underlying drivers of our business over the last year and the first month of 2009.

### VALUE-AT-RISK



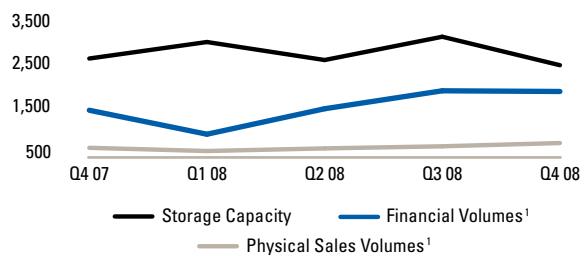
### NORTH AMERICAN NATURAL GAS

Volumetric Information (bcf/day)



### NORTH AMERICAN CRUDE OIL

Volumetric Information (mbbls/day)



<sup>1</sup> Marketing's physical and financial volumes represent the exiting average daily volume for the quarter.

The graphs reflect our efforts to re-focus our North American gas business back on its core marketing and optimization activities, as well as prudently manage the working capital deployed in the business.

- Physical volumes are down 25% from their peak with less focus on buying and selling gas at a point to realize a margin.
- At December 31, 2008, financial volumes were down 54% from their peak given our focus on exiting trading positions and optimizing assets.
- Gas storage capacity for the next season is back in line with 2005 levels, giving plenty of capacity to optimize on behalf of ourselves and our customers.

We also reduced the risk held in our forward trading portfolio as demonstrated by reducing our value-at-risk 44% from its peak earlier in the year. Over the past few months, we have significantly reduced our financial trading positions. We have focused our financial contracts on protecting and optimizing the value of our near-term physical assets where market liquidity exists.

The credit crisis that impacted financial markets caused some of our counterparties to restructure or declare bankruptcy. In September 2008, Lehman Brothers filed for bankruptcy protection and our exposure to them in our trading operations was approximately \$39 million. The entire amount was expensed in the third quarter although we continue to pursue recovery of these amounts. We also provided an additional \$15 million for credit risk with our counterparties. The majority of our counterparties are integrated oil companies, crude oil refiners and marketers, and large utilities.

Results from our marketing group vary between periods and historical results are not necessarily indicative of future results. Marketing results depend on a variety of factors such as market volatility, changes in time and location spreads, the manner in which we use our storage and transportation assets and the change in value of the financial instruments we use to hedge these assets.

### 2007 vs 2006—Reduced energy marketing net revenue decreased net income by \$373 million

Results from our energy marketing group in 2007 were below the record year we experienced in 2006 as there were fewer market events to capitalize on, and fundamental changes in commodity markets were difficult to predict with confidence.

As part of our gas marketing strategy, we hold physical transportation and storage capacity contracts that allow us to take advantage of pricing differences between locations (i.e. west vs. east) and time periods (i.e. summer vs. winter). These strategies, particularly time spreads, contributed less to net revenue in 2007 as there were fewer significant weather-related market events (hurricanes or cold winter weather) to capitalize on. These events typically cause time spreads to widen and location spreads to dislocate, presenting trading opportunities for us. In addition, gas prices were supported throughout the year by high oil prices despite record gas storage levels. We were successful at generating revenue through the day-to-day optimization of our transportation and storage capacity, as well as our fee-for-service asset management activities.

The contribution of our North American crude oil marketing team was lower than 2006 as their portfolio, both physical and financial, was positioned to take advantage of contango (rising

forward month prices) in the crude oil forward curve. Late summer, near-term crude oil prices moved up sharply, moving the forward curve from contango to backwardation (falling forward month prices). As a result, we suffered losses in our financial time spread positions. We continued to capture profits from location and quality spreads by diverting crude oil to more attractive markets or blending to enhance crude quality.

Our 2007 results include fair value gains of \$79 million on our natural gas and crude oil in storage and pipelines in the fourth quarter. New inventory standards under Canadian GAAP require us to carry our trading commodity inventories at fair value, rather than at cost as was previously the case. We adopted these new rules in the fourth quarter of 2007.

In late 2006, we de-designated certain futures contracts that were designated as cash flow hedges of future sales of our natural gas in storage. These contracts were de-designated since it became uncertain that the future sales would occur within the designated time frame. As it was reasonably possible that the future sales could have taken place as designated at the inception of the hedging relationship, gains of \$65 million on the futures contracts were deferred at December 31, 2006. These gains were recognized in marketing and other income during the first quarter of 2007.

### Composition of Net Marketing Revenue

(Cdn\$ millions)

	2008	2007	2006
Trading Activities (Physical and Financial)	(287)	147	520
Non-Trading Activities	30	20	20
<b>Total Net Marketing Revenue</b>	<b>(257)</b>	<b>167</b>	<b>540</b>

#### Trading Activities

In our energy marketing group, we enter into contracts to purchase and sell crude oil and natural gas. We also use financial and derivative contracts, including futures, forwards, swaps and options for hedging and trading purposes. We account for all derivative contracts using fair value accounting and record the net gain or loss from their revaluation in marketing and other income. The fair value of these instruments is included with accounts receivable or payable. They are classified as long-term or short-term based on their anticipated settlement date.

#### Other Activities

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

#### Fair Value of Derivative Contracts

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

As a basis for establishing fair value, we utilize a mid-market pricing convention between bid and ask and then adjust our pricing to the ask price when we have a net short position and the bid price when we have a net long position. This adjustment reflects an estimated exit price and incorporates the impact of liquidity when the bid-ask spread widens in less liquid markets. We incorporate the credit risk associated with counterparty default, as well as Nexen's own credit risk, into our estimates of fair value.

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

- Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 consists of financial instruments such as exchange-traded derivatives and we use information from markets such as the New York Mercantile Exchange.
- Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reported date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value, volatility factors, and broker quotations, which can be substantially observed or corroborated

in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter physical forwards and options, including those which have prices similar to quoted market prices. We obtain information from sources such as the Natural Gas Exchange, independent price publications and over-the-counter broker quotes.

- Level 3—Valuations in this level are those with inputs which are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value. Level 3 instruments may include items based on pricing services or broker quotes where we are unable to verify the observability of inputs into their prices. Level 3 instruments include longer-term transactions, transactions in less active markets or transactions at locations for which pricing information is not available. In these instances, internally developed methodologies are used to determine fair value which primarily includes extrapolation of observable future prices to similar locations, similar instruments or later time periods.

At December 31, 2008, the fair value of our derivative contracts in our energy marketing trading activities totaled \$63 million. This includes contracts used to economically hedge our physical storage and transportation contracts which cannot be carried at fair value until they are used as well as other trading contracts. Below is a breakdown of the derivative fair value by valuation method and contract maturity.

<i>(Cdn\$ millions)</i>	Maturity				Total
	< 1 year	1-3 years	4-5 years	> 5 years	
Level 1 – Actively Quoted Markets	90	(51)	(23)	(3)	13
Level 2 – Based on Other Observable Pricing Inputs	130	(4)	8	(2)	132
Level 3 – Based on Unobservable Pricing Inputs	(80)	(2)	–	–	(82)
<b>Total</b>	<b>140</b>	<b>(57)</b>	<b>(15)</b>	<b>(5)</b>	<b>63</b>

### Changes in Fair Value of Derivative Contracts

<i>(Cdn\$ millions)</i>	Total
<b>Fair Value at December 31, 2007</b>	<b>6</b>
Change in Fair Value of Contracts	(158)
Net Losses (Gains) on Contracts Closed	227
Changes in Valuation Techniques and Assumptions <sup>1</sup>	(12)
<b>Fair Value at December 31, 2008</b>	<b>63</b>

<sup>1</sup> Our valuation methodology has been applied consistently each period, with the exception of two portfolio level reserves that were included in the first quarter of 2008 to account for: a) credit risk associated with counterparty defaults; and b) liquidity risk in our portfolio.

The fair values of our derivative contracts will be realized over time as the related contracts settle. Until then, the value of certain contracts will vary with forward commodity prices and price differentials. The average term of our derivative contracts is approximately 1.5 years. Those maturing beyond one year primarily relate to North American natural gas positions.

## CHEMICALS

<i>(Cdn\$ millions)</i>	2008	2007	2006
Net Sales	477	414	407
Sales Volumes (thousand short tons)			
Sodium Chlorate	495	478	487
Chlor-alkali	469	465	451
Operating Profit <sup>1</sup>	125	118	118
Operating Margin <sup>2</sup>	26%	29%	29%
Chemicals Contribution to Income Before Income Taxes <sup>3</sup>	(14)	64	44
Capacity Utilization	92%	94%	95%

<sup>1</sup> Net sales less operating costs, transportation and other.

<sup>2</sup> Operating profit divided by net sales.

<sup>3</sup> Includes foreign exchange gains and losses on long-term debt.

### 2008 vs 2007—Lower Chemicals contribution decreased net income by \$76 million

North America sodium chlorate revenues increased 14% in 2008 as a result of higher realized selling prices and higher sales volumes. Price increases implemented in North America in the first and third quarters more than offset the impact of the stronger Canadian dollar on US-dollar denominated sales. Strong demand from US customers contributed to the increase in sales volumes. North American chlor-alkali revenues were up 11% in 2008 as we realized higher selling prices for caustic soda. These increases have been offset by higher operating and transportation costs, as the price of fuel and power increased during 2008. In Brazil, we have a pass-through contract with our primary customer Aracruz Cellulose that allows us to amend our sales prices when operating costs change. Higher costs in 2008 increased the sales revenues we receive from them.

Chemicals contribution to income includes foreign exchange losses of \$54 million, primarily from unrealized losses on the revaluation of US-dollar denominated long-term debt.

### 2007 vs 2006—Higher Chemicals contribution increased net income by \$27 million

Realized North America chlorate prices were up 5% in 2007 and sales volumes remained strong, despite unplanned maintenance of our facilities and pulp mill shut downs. The full effect of the price increase was partially eroded by the strengthening Canadian dollar which reduced US-dollar denominated sales by \$9 million. Brazilian sales remained strong with continued demand from our main pulp mill customer Aracruz Cellulose.

Operating profit includes foreign exchange gains of \$30 million, primarily from unrealized gains on revaluation of US-dollar denominated long-term debt.

## CORPORATE EXPENSES

### General and Administrative (G&A)

<i>(Cdn\$ millions)</i>	2008	2007	2006
General and Administrative Expense before Stock-Based Compensation	417	336	345
Stock-Based Compensation <sup>1</sup>	(160)	38	210
<b>Total</b>	<b>257</b>	<b>374</b>	<b>555</b>

<sup>1</sup> Includes cash and non-cash expenses related to our tandem option plan and stock appreciation rights plan.

### 2008 vs 2007—Lower costs increased net income by \$117 million

Changes in our share price create volatility in our net income as we account for stock-based compensation using the intrinsic-value method. This method uses our share price at the end of the reporting period to determine our stock-based compensation expense and related obligations. During the year, we recovered non-cash stock based compensation costs of \$272 million as our stock price closed at \$21.45/share at the end of 2008, compared to \$32.10/share the previous year. This recovery was

partially offset by cash payments for stock-based compensation programs of \$112 million, 24% lower than 2007.

G&A expense before stock-based compensation increased \$81 million, primarily as a result of higher employee costs and cost inflation. An integral part of our strategy to expand our oil and gas operations has been to actively recruit experienced employees, positioning us for success in our core areas. We have been actively recruiting skilled individuals to strengthen our teams in Norway and the US.

**2007 vs 2006—Lower costs increased net income by \$181 million**

G&A expense dropped 33% from 2006 with lower stock-based compensation expense. At the end of 2007, our stock price closed unchanged from the end of 2006. As a result, most of our 2007 stock-based compensation expense is related to vesting of stock-based compensation plans. Cash payments to

employees for stock-based compensation programs increased 24% from 2006 to \$147 million.

During the year, we incurred additional employee costs as we continue to expand oil and gas operations internationally and marketing operations in Europe and North America. This was offset by lower variable compensation on oil and gas and marketing operations.

**Interest**

<i>(Cdn\$ millions)</i>	<b>2008</b>	<b>2007</b>	<b>2006</b>
Interest	334	341	294
Less: Capitalized	(240)	(173)	(241)
<b>Net Interest Expense</b>	<b>94</b>	<b>168</b>	<b>53</b>
Effective Interest Rate	5.9%	6.2%	6.3%

**2008 vs 2007—Lower net interest expense increased net income by \$74 million**

Our financing costs are \$7 million lower than the previous year as our strong cash flow reduced our debt needs. Lower interest rates on our variable rate debt also reduced interest costs. In the third quarter, we completed an internal reorganization and financing of our assets in the UK. This required us to draw down approximately US\$1 billion under our term credit facilities. As a consequence, our financing costs increased in the fourth quarter of 2008.

Interest capitalized on our major development projects increased \$67 million in 2008 compared to 2007. Our Long Lake capital costs include \$207 million of capitalized interest, \$49 million higher than last year. We also capitalized interest of \$25 million on our Ettrick development. We continue to capitalize interest on our development project at Usan and the construction of the

fourth platform at Buzzard. We expect net interest expense to increase in 2009 by approximately \$150 million when we cease capitalizing interest at Long Lake and Ettrick.

**2007 vs 2006—Higher net interest expense decreased net income by \$115 million**

Financing costs increased \$47 million from 2006. Additional borrowings to finance our 2007 capital program increased interest costs by approximately \$69 million. This was partially offset by the stronger Canadian dollar which reduced our US-dollar denominated interest by \$22 million.

Interest capitalized on our major development projects was lower by \$68 million from 2006 as we stopped capitalizing interest on the Syncrude Stage 3 expansion and Buzzard when these projects were brought on stream.

**Income Taxes**

<i>(Cdn\$ millions)</i>	<b>2008</b>	<b>2007</b>	<b>2006</b>
Current	859	434	368
Future	598	358	315
<b>Total Provision for Income Taxes</b>	<b>1,457</b>	<b>792</b>	<b>683</b>
Effective Tax Rate	46%	42%	53%

**2008 vs 2007—Effective tax rate increases from 42% to 46%**

Our provision for income taxes increased \$665 million or 84% from the prior year, while our effective tax rate increased 4%. This increase was primarily due to record commodity prices and strong production at Buzzard in the UK, which has a corporate tax rate on oil and gas activities of 50%. Current income taxes include cash taxes in Yemen, the UK, Colombia, Norway and the US.

**2007 vs 2006—Effective tax rate decreases from 53% to 42%**

Our 2007 effective tax rate was lower than 2006, as we recorded additional tax expense in 2006 due to a UK tax rate increase. Excluding the impact of this rate increase, our effective tax rate in 2006 would have been 33%. The 2007 increase is due to a higher proportion of earnings from the UK where the corporate income tax rate on oil and gas activities is 50%. Current income taxes include cash taxes in Yemen, the UK, Colombia and the US.

## Other

(Cdn\$ millions)

	2008	2007	2006
Increase (Decrease) in Fair Value of Crude Oil Put Options	203	(43)	(11)
Block 51 Settlement	–	–	(151)
Business Interruption Insurance Proceeds	–	–	154

In early 2008, we purchased put options on approximately 70,000 bbls/d of our 2009 crude oil production. These options establish a Dated Brent floor price of US\$60/bbl on these volumes, are settled annually and provide a base level of price protection without limiting our upside to higher prices. Accounting rules require that these options be recorded at fair value throughout their term. As a result, changes in forward crude oil prices create gains or losses on these options at each period end. The put options were purchased for \$14 million and are carried at fair value. During the third quarter of 2008, Lehman Brothers, one of the put option counterparties filed for bankruptcy protection, which impacts 25,000 bbls/d of our 2009 put options. The carrying value of these put options has been reduced to nil. At December 31, 2008, the remaining options had a fair value of \$233 million, creating an unrealized gain of \$203 million.

During 2007, we purchased put options on 36 million barrels of our 2008 crude oil production. These options establish a Dated Brent floor price of US\$50/bbl on these volumes. The put options were purchased for \$24 million; however, strong crude oil prices reduced the fair value of these options to nil, and we recorded a loss of \$24 million during 2007.

During 2006, we purchased put options on approximately 105,000 bbls/d of our 2007 crude oil production for \$26 million, establishing a WTI floor price of US\$50/bbl on these volumes. We recognized a loss of \$7 million for the year ended December 31, 2006 as an increase in the forward WTI prices lowered the fair value of the options. In 2007, strengthening WTI reduced the market value of the options to nil, creating a loss of \$19 million.

Following our North Sea acquisition in late 2004, we purchased put options on 60,000 bbls/d of oil production for 2006 creating an average floor price for this production of US\$38/bbl. Strong WTI prices in 2006 caused us to expense \$4 million as the market value of the remaining options was reduced to nil.

In 2006, a court of arbitration concluded that we breached an Area of Mutual Interest agreement with Occidental Petroleum Corporation (Occidental). As a result, Occidental was entitled to monetary damages. In late 2006, we settled the arbitration by agreeing to pay Occidental US\$135 million (\$151 million) as monetary damages.

In 2006, we received \$154 million of business interruption insurance proceeds related to 2005 production losses caused by Gulf of Mexico hurricanes and by generator failures in our UK operations.

## OUTLOOK FOR 2009

In 2009, we plan to invest \$2.6 billion in capital activities on our oil and gas, and Syncrude operations as follows:

- 34% on our existing producing assets, including the fourth platform at Buzzard;
- 31% in development projects to progress Usan, offshore West Africa and bring Etrick, in the North Sea, and Longhorn, in the Gulf of Mexico, on stream in 2009;
- 27% on advancing our Horn River shale gas play and on exploration and appraisal opportunities in our key regions—the North Sea, Gulf of Mexico and offshore West Africa; and
- 8% on early stage development projects expected to contribute future production and cash flow including future phases of oil sands in the Athabasca region.

The amount of this capital investment could be reduced due to the current uncertain economic environment. Details of our 2009 capital program are included in the Capital Investment section of the MD&A.

## Daily Production

In 2009, we expect net production to grow approximately 10% compared to 2008 and to range between 225,000 and 240,000 boe/d (255,000 and 270,000 boe/d before royalties). We expect to ramp up bitumen production at Long Lake as well as first oil production from Etrick in the North Sea and Longhorn in the Gulf of Mexico. These will more than offset natural field declines in Yemen and a shut-down of the Buzzard platform for four weeks as we install the fourth platform.

## 2009 Estimated Production

<i>(mboe/d)</i>	2009 Estimated Production		2008 Production	
	Before Royalties	After Royalties	Before Royalties	After Royalties
United Kingdom	100–115	100–115	103	103
Yemen	40–45	23–28	56	31
Canada	35–40	27–32	38	30
United States	20–25	17–22	22	19
Syncrude	20–25	18–23	21	18
Long Lake Bitumen	20–25	18–23	4	4
Other International	3–5	2–4	6	5
<b>Total</b>	<b>255–270</b>	<b>225–240</b>	<b>250</b>	<b>210</b>

## Cash Flow and Sensitivities

We expect to generate cash flow of between \$2.3 and \$2.9 billion from operating activities in 2009, after cash taxes of approximately \$1 billion, assuming the following:

WTI (US\$/bbl)	\$50–\$65
NYMEX Natural Gas (US\$/mmbtu)	\$6.50
US to Canadian Dollar Exchange Rate	\$0.83

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

<i>(Cdn\$ millions)</i>	
WTI—US\$1/bbl change above US\$60	50
WTI—US\$1/bbl change below US\$60	40
NYMEX Natural Gas—US \$0.50/mcf change	34
Exchange Rate—\$0.01 US/Cdn change	36

## LIQUIDITY AND CAPITAL RESOURCES

### Capital Structure

<i>(Cdn\$ millions)</i>	December 31 2008	December 31 2007
<b>Net Debt<sup>1</sup></b>		
Bank Debt	1,448	413
Public Senior Notes	4,582	3,758
Total Senior Debt	6,030	4,171
Subordinated Debt	548	439
Total Debt	6,578	4,610
Less: Cash and Cash Equivalents	(2,003)	(206)
<b>Total Net Debt</b>	<b>4,575</b>	<b>4,404</b>
<b>Shareholders' Equity</b>	<b>7,139</b>	<b>5,610</b>

<sup>1</sup> Includes all of our debt and is calculated as long-term debt and short-term borrowings less cash and cash equivalents.

### Net Debt

We use net debt as a key indicator of our leverage and to monitor the strength of our balance sheet. Net debt is directly related to our operating cash flows and capital investment. We ended the year with net debt of approximately \$4.6 billion, \$171 million higher than 2007. The year-over-year change in our net debt results from:

<i>(Cdn\$ millions)</i>	2008	2007
Capital Investment	3,066	3,401
Cash Flow from Operating Activities	(4,354)	(2,830)
(Excess) Deficiency	(1,288)	571
Dividends on Common Shares	92	53
Issue of Common Shares	(64)	(56)
Repurchase of Common Shares for Cancellation	338	–
Foreign Exchange Translation of US-dollar Debt and Cash	1,012	(745)
Net Proceeds on Disposition of Assets	(6)	(4)
Other	87	(145)
<b>Increase (Decrease) in Net Debt</b>	<b>171</b>	<b>(326)</b>

The change in our net debt, combined with strong cash flow and earnings, have improved our 2008 leverage as reflected in the following ratios:

<i>(times)</i>	<b>2008</b>	<b>2007</b>	<b>2006</b>
Net Debt to Cash Flow from Operating Activities	1.1	1.6	2.0
Interest Coverage <sup>1</sup>	15.6	12.1	9.6

<sup>1</sup> Earnings before interest, taxes, DD&A, exploration and other non-cash expenses, divided by interest expense (before capitalized interest).

Our business strategy is focused on value-based growth through full-cycle exploration and development of conventional and unconventional resources, supplemented by strategic acquisitions when appropriate. Since most of our projects have long-cycle times, requiring significant amounts of capital prior to cash flow generation, we have successfully leveraged our balance sheet many times in the past, including to:

- develop the Masila project in Yemen in 1993;
- acquire Wascana in 1997;
- repurchase 20 million common shares in 2000;
- acquire the remaining interest in Aspen in 2003;
- acquire the Buzzard project and other key assets in the North Sea in 2004; and
- construct the first phase of Long Lake.

Each time, we exceeded our internal net debt to cash flow target band, we successfully bring our leverage down through asset sales and incremental cash flows.

### Change in Working Capital

<i>(Cdn\$ millions)</i>	<b>December 31 2008</b>	<b>December 31 2007</b>	<b>Increase (Decrease)</b>
Cash and Cash Equivalents	2,003	206	1,797
Restricted Cash	103	203	(100)
Accounts Receivable	3,163	3,502	(339)
Inventories and Supplies	484	659	(175)
Accounts Payable and Accrued Liabilities	(3,326)	(4,180)	(854)
Other	76	22	54
<b>Total</b>	<b>2,503</b>	<b>412</b>	

Our cash and cash equivalents are significantly higher due to higher operating cash flows and the proceeds of borrowings made on our term credit facilities. Strong production volumes and record commodity prices contributed to higher operating cash flows. We also completed an internal reorganization and financing of our UK assets, which required a draw of approximately US\$1 billion under our term credit facilities, with a corresponding increase in cash.

Accounts receivable and payable for our Energy Marketing group decreased \$250 million and \$600 million from 2007, respectively. These decreases were due to a combination of: (i) lower commodity prices in the fourth quarter of 2008 that reduced the size of our outstanding physical and financial contracts; and (ii) exiting a portion of our derivative positions as part of a strategic decision to reduce the size of our marketing operation. Lower year-end prices also reduced the value of our commodity trading

inventories. Additionally, our accrued payables were lower as our outstanding stock-based compensation obligations were reduced by \$296 million at the end of 2008.

The stronger US dollar at the end of the year impacted our US-dollar denominated working capital by increasing accounts receivable, inventories and accounts payable by approximately \$335 million, \$80 million and \$290 million, respectively. The US/ Canadian year-end exchange rate increased 25% from 2007.

### Liquidity

We generally rely on operating cash flows to fund capital requirements and provide liquidity. Given the long cycle-time of some of our development projects and volatile commodity prices, it is not unusual for capital expenditures to exceed our cash flow in any given year. We also require liquidity for our energy marketing business. We believe that maintaining strong

liquidity is critical during periods of uncertain economic markets. We currently have liquidity of over \$3.5 billion after acquiring the additional Long Lake interest in January 2009 that is comprised of cash and undrawn committed credit facilities available until 2012.

We maintain significant committed credit facilities. At December 31, 2008, we had unsecured term credit facilities of \$3.7 billion (US\$3.1 billion) that are available until 2012. Of these facilities, \$1.2 billion (US\$1 billion) was drawn and \$381 million (US\$311 million) was utilized to support letters of credit. We also had \$613 million (US\$501 million) of uncommitted, unsecured credit facilities, of which \$29 million (US\$24 million) was supporting letters of credit outstanding at December 31, 2008. Additionally, Canexus had \$420 million (US\$343 million) of committed, secured term credit facilities available until 2011

of which \$223 million (US\$182 million) was drawn down at December 31, 2008.

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

The following table shows how we finance our business activities. When our operating cash flows exceed our investment requirements, we generally pay down debt or return cash to shareholders. We borrow or issue equity to fund investment requirements that exceed our operating cash flow.

<i>(Cdn\$ millions)</i>	<b>2008</b>	<b>2007</b>	<b>2006</b>	<b>2005</b>	<b>2004</b>
Cash Flow from Operating Activities	4,354	2,830	2,374	2,143	1,606
Cash Flow from Investing Activities	(3,189)	(3,281)	(3,388)	(1,864)	(4,013)
Surplus (Deficiency)	1,165	(451)	(1,014)	279	(2,407)
Cash Flow from Financing Activities	322	677	1,081	(274)	1,426
<b>Net Cash Generated (Used)</b>	<b>1,487</b>	<b>226</b>	<b>67</b>	<b>5</b>	<b>(981)</b>

In late 2003, we pre-funded debt repayments by raising more than \$1 billion in senior and subordinated debt. We used these funds in 2004 to repay higher-cost debt and, coupled with acquisition credit facilities, acquired the North Sea assets. In 2005, we used cash flow and proceeds from asset dispositions to fund our capital program and repay debt. In 2006, we borrowed approximately \$1 billion under our committed term credit facilities and used cash flow from operating activities to fund our capital program. In 2007, we issued US\$1.5 billion in senior debt to repay outstanding term credit facilities and \$150 million in medium term notes, and to fund our 2007 capital program.

In 2008, our cash flow from operating activities exceeded capital expenditures by approximately \$1.3 billion and we used this excess to build our cash balances, repurchase common shares and repay debt. In June, we repaid maturing medium term notes of \$125 million and in the third quarter, we borrowed approximately US\$1 billion under our term credit facilities. The draw down under our term credit facilities resulted from an internal reorganization and financing of our UK North Sea assets.

In the third quarter, we received approval from the Toronto Stock Exchange (TSX) for a Normal Course Issuer Bid (Bid). Under the Bid, we are able to repurchase up to 10% of our public float of

common shares (approximately 53 million common shares) for cancellation. Purchases under the Bid commenced August 6, 2008 and can be made until August 5, 2009. We repurchased 12 million common shares at an average price of \$27.85/share for a cost of \$338 million. We currently have no plans to repurchase common shares until economic conditions improve.

Our marketing business also requires liquidity to support its activities. We require liquidity for working capital, cash or credit lines to fund collateral requirements and to absorb unexpected market or credit losses. The commercial agreements our marketing business enters into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. These agreements typically require collateral be posted if adverse credit-related events, such as reduced credit rating to non-investment grade, occur. Additionally, our exchange-traded contracts require that we provide margin based on daily fluctuations in the value of our contracts. The largest single day margin call we received during 2008 was \$60 million. In evaluating our liquidity requirements, we consider the current requirements of our marketing business as well as additional collateral or other payments that could be required if our credit ratings were reduced.

## Future Liquidity

Our future liquidity depends upon cash flow generated from our operations, existing committed credit facilities and our ability to access debt and equity markets. Our announced 2009 capital investment budget is approximately \$2.8 billion which we expect to finance from cash flow and existing cash. We continue to monitor economic conditions and commodity prices and will adjust our capital investment program accordingly. We are also working with suppliers and contractors to renegotiate supply rates that reflect existing market conditions.

In 2009, we expect cash flow of between \$2.3 and \$2.9 billion (before remediation and geological and geophysical expenditures) assuming:

WTI (US\$/bbl)	\$50-\$65
NYMEX Natural Gas (US\$/mmbtu)	\$6.50
US to Canadian Dollar Exchange Rate	\$0.83

Changes in commodity prices and exchange rates will impact our cash flow and borrowing requirements. Refer to the Outlook for 2009 section on page 65 to see how changes in the above assumptions can impact our cash flow.

At December 31, 2008 we have \$2 billion in cash, \$2.5 billion (US\$2.1 billion) of undrawn committed credit facilities and \$613 million of unsecured credit facilities. We have no debt maturities over the next few years and the average term of our public debt is approximately 18 years. When we combine these factors with our strategic capital investment plans, we believe we are well positioned to bring our near completion projects to production and pursue our next generation of growth while preserving our liquidity. At the end of 2008, we agreed to acquire an additional 15% interest in the Long Lake Project and the joint venture

lands from OPTI Canada Inc. for \$735 million. The acquisition closed late January 2009 and was financed using our existing term credit facilities and cash on hand. We now have a 65% interest in the Long Lake Project and are the sole operator of the resource and upgrader.

For the past several years, we have invested significant capital in a number of major development projects including Buzzard and Long Lake. The large capital investment required in these projects is behind us and we expect these assets to make significant contributions to our future cash flows. In addition, we expect Ettrick and Longhorn to contribute to cash flows when they start production in 2009. The cash flows generated from these projects allow us to repay debt or invest in our next generation of new growth projects such as Usan, offshore West Africa and shale gas in the Horn River basin. In 2009, we expect to invest \$515 million to progress our Usan development, and \$160 million in the UK North Sea to bring Ettrick on stream and assess development options for Blackbird. While these development projects lack exploration risk, they are subject to other risks including higher than anticipated capital costs or delayed start-up. We maintain significant undrawn committed credit facilities to manage these risks. We also have a US\$2.5 billion shelf prospectus filed in the US and Canada for sales of debt securities and common shares.

We are well positioned with our current debt structure and have no significant debt repayments until 2011. Our only debt covenant requires us to maintain a long-term debt to EBITDA ratio of less than 3.5. At December 31, 2008, this ratio was approximately 1.2 times. Based on our current debt levels and operations, we do not expect to exceed 3.5 in the foreseeable future.

<i>(Cdn\$ millions)</i>	2009	2010	2011	2012	2013
Term Credit Facilities <sup>1</sup>	-	-	-	1,225	-
Long-Term Notes	-	-	-	-	612
Canexus LP Term Credit Facilities	-	-	223	-	-
Canexus LP Notes	-	-	-	-	61
<b>Total</b>	-	-	<b>223</b>	<b>1,225</b>	<b>673</b>

<sup>1</sup> \$3.7 billion (US\$3.1 billion) available until 2012.

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

In 2008, the board declared common share dividends of \$0.175. In each of the three years preceding 2008, the board declared common share dividends of \$0.10 per share each year.

## Contractual Obligations, Commitments and Guarantees

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

(Cdn\$ millions)	Payments				
	Total	< 1 year	1-3 years	4-5 years	> 5 years
Long-Term Debt	6,652	–	223	1,898	4,531
Interest on Long-Term Debt <sup>1</sup>	7,611	331	662	657	5,961
Operating Leases <sup>2</sup>	715	91	224	205	195
Capital Leases	125	6	12	12	95
Energy Commodity Contract Liabilities	956	636	290	25	5
Transportation and Storage Commitments <sup>2</sup>	1,261	379	411	267	204
Work Commitments and Purchase Obligations <sup>3</sup>	4,228	2,029	1,557	567	75
Asset Retirement Obligations	2,393	35	70	305	1,983
<b>Total</b>	<b>23,941</b>	<b>3,507</b>	<b>3,449</b>	<b>3,936</b>	<b>13,049</b>

<sup>1</sup> Excludes interest on term credit facilities of \$3.7 billion (US\$3.1 billion) and Canexus term credit facilities of \$420 million (US\$343 million) as the amounts drawn on the facilities fluctuate. Based on amounts drawn at December 31, 2008 and existing variable interest rates, we would be required to pay \$19 million per year until the outstanding amounts on the term credit facilities are repaid.

<sup>2</sup> Payments for operating leases and transportation and storage commitments are deducted from our cash flow from operating activities.

<sup>3</sup> Some of these payments relate to work commitments that we can cancel without penalties or additional fees.

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

- Short-term and long-term debt amounts are included on our December 31, 2008 Consolidated Balance Sheet.
- Operating leases include the minimum lease payment obligations associated with leases for office space, rail cars, vehicles and processing agreements that allows our production to flow through third-party processing facilities.
- Capital leases include pipeline commitments primarily related to production at Long Lake.
- Energy commodity contract liabilities include the purchase and sale of physical quantities of oil and natural gas, and financial derivatives used to manage our exposure to commodity prices. For contracts where the price is based on an index, the amount is based on forward market prices at December 31, 2008. For certain contracts, we may net settle. These contracts are included in our Consolidated Balance Sheet at fair value.
- Work commitments include non-discretionary capital spending for drilling, seismic, facilities construction and other development commitments in our international operations, and includes commitments for the Usan development project in Nigeria over the next five years (\$1,024 million). Also, included in purchase obligations is \$735 million payable in January

2009 for purchasing an additional 15% ownership interest in the Long Lake Project. Since the timing of certain payments is difficult to determine with certainty, the table was prepared using our best estimates. The majority of our 2009 capital investment is discretionary.

- We have included \$1,409 million in work commitments for drilling rigs we have contracted in the UK, Norway and the Gulf of Mexico, over the next five years.
- We have \$2,393 million of undiscounted asset retirement obligations after inflation. As of December 31, 2008, the discounted value (\$1,059 million) of these estimated obligations was provided for in our Consolidated Financial Statements (including \$35 million of estimated current obligations). Since timing of any payments is difficult to determine with certainty, the table was prepared using our best estimates.
- We have unfunded obligations of \$171 million (Nexen—\$112 million; Canexus—\$9 million; Syncrude—\$50 million) under our defined benefit pension plans. Our obligations for Nexen and Canexus include \$63 million that is unfunded as a result of statutory limitations. These obligations are backed by irrevocable letters of credit. In addition, existing market conditions created a solvency deficiency of \$46 million for the Nexen defined benefit pension plan during the year. While we were required to fund this over the next five years, we funded this shortfall in February 2009.
- We have excluded obligations on our tandem option and stock appreciation rights programs as the amount and timing of cash payments are not determinable.

- We have excluded our normal purchase arrangements as they are discretionary and are reflected in our expected cash flow from operating activities and capital expenditures for 2009.
- We have excluded our future income tax liabilities as the amount and timing of any cash payment for income taxes is based on taxable income for each fiscal year in the various jurisdictions where we operate. We have also excluded future income tax liabilities as they relate to uncertain tax positions, as we cannot provide a reasonable estimate as to if, or when future payments would be required.

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

### **Credit Ratings**

Currently, our senior debt is rated Baa2 by Moody's Investor Service, Inc. (Moody's), BBB by Dominion Bond Rating Service (DBRS) and BBB- by Standard & Poor's (S&P). DBRS and S&P currently rate our outlook as stable. Moody's has placed our rating under review for possible downgrade. We believe our strong financial results, ample liquidity and financial flexibility continue to support our credit ratings.

### **Financial Assurance Provisions in Commercial Contracts**

The commercial agreements our energy marketing group enters into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. The agreements normally require collateral to be posted if an adverse credit-related event, such as a drop in credit ratings, occurs. Based on contracts in place and commodity prices at December 31, 2008, we could be required to post collateral of up to \$1.3 billion if we were downgraded to non-investment grade. These obligations are reflected on our balance sheet. The posting of collateral merely accelerates the payment of such amounts and lowers our available liquidity. Just as we may be required to post collateral if we were downgraded below investment grade, we have similar provisions in many of our contracts that allow us to demand certain counterparties post collateral for amounts they owe us if they are downgraded to non-investment grade.

### **Off-Balance Sheet Arrangements**

We have no off-balance sheet arrangements that would have a material adverse effect on our liquidity, consolidated financial position or results of operations. We use operating leases in the normal course of business as disclosed in Contractual Obligations, Commitments and Guarantees on page 69 and in Note 16 to the Consolidated Financial Statements, which is incorporated herein by reference.

At December 31, 2008, we had outstanding letters of credit supported by \$381 million (US\$311 million) of unsecured term credit facilities and \$29 million (US\$24 million) of uncommitted unsecured credit facilities.

### **Contingencies**

We have no contingencies that would have a material adverse effect on our liquidity, consolidated financial position or results of operations. See Note 16 to the Consolidated Financial Statements, which is incorporated here by reference for a discussion of our contingencies.

### **CRITICAL ACCOUNTING ESTIMATES**

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

### **Oil and Gas Accounting—Reserves Determination**

We follow the successful efforts method of accounting for our oil and gas activities, as described in Note 1 to our Consolidated Financial Statements. Successful efforts accounting depends on the estimated reserves we believe are recoverable from our oil and gas properties.

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. To estimate the economically recoverable oil and natural gas reserves and related future net cash flows, we incorporate many factors and assumptions including:

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

We believe these factors and assumptions are reasonable based on the information available to us at the time we prepare our estimates. However, these estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

Management is responsible for the estimates of the quantities of proved oil and gas reserves and for preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements, generally accepted industry practices in the US and the standards of the Canadian Oil and Gas Evaluation Handbook modified to reflect SEC requirements.

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

The internal qualified reserves evaluator assesses whether our reserves estimates and the *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein*, included in the Supplementary Financial Information, have been prepared in accordance with our reserve standards. His opinion stating that the reserves information has, in all material respects, been prepared according to our reserves standards is included as an exhibit to this Form 10-K.

Our reserves are based on internal estimates. To increase our confidence in our estimates, we have at least 80% of our oil and gas and Syncrude reserves either evaluated or audited annually by independent qualified reserves consultants. Given that reserve estimates are based on numerous assumptions, interpretations and judgments, differences frequently arise between the estimates prepared by different qualified estimators. When the initial estimate on the portfolio of properties differs by greater than 10%, we work with the independent reserves consultant to reconcile the difference to within 10%. Estimates pertaining to individual properties within the portfolio often differ by significantly more than 10%, either positively or negatively. We do not attempt to resolve each property to within 10% as it would be time and cost prohibitive given the number of wells in which we have an interest.

The nature and extent of the independent evaluations and audits, and the results thereof, are provided in the section on Reserves, Production and Related Information on page 15.

The Board of Directors has a Reserves Review Committee (Reserves Committee) to assist the board and the Audit and Conduct Review Committee to oversee the annual review of our oil and gas and Syncrude reserves and disclosures of reserves data and related oil and gas and mining activities. The Reserves Committee is comprised of three or more directors, the majority of whom are independent and familiar with estimating oil and gas reserves. The Reserves Committee meets with management periodically to review the reserves process, the portfolio of properties selected by management for independent assessment, results and related disclosures. The Reserves Committee appoints and meets with the internal qualified reserves evaluator and independent reserves consultants, independent of management, to review the scope of their work, whether they have had access to sufficient information, the nature and satisfactory resolution of any material differences of opinion, and in the case of the independent reserves consultants, their independence. In the event of a proposed change to the areas of responsibility of either an independent reserves consultant or the internal qualified reserves evaluator, the Reserves Committee inquires whether there have been disputes between the respective party and management.

The Reserves Committee has reviewed our procedures for preparing the reserves estimates and related disclosures. It reviewed the information with management, and met with the internal qualified reserves evaluator and the independent qualified reserves consultants. As a result, the Reserves Committee is satisfied that the internally-estimated reserves are reliable and

free of material misstatement. Based on the recommendation of the Reserves Committee, the board has approved the reserves estimates and related disclosures in the Form 10-K.

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

- determining whether or not an exploratory well has found economically producible reserves. If successful, we capitalize the costs of the well, and if not, we expense the costs immediately. In 2008, \$203 million of our total \$401 million spent on exploration drilling was expensed. If none of our exploration drilling had been successful, our net income would have decreased by \$125 million, net of income tax.
- calculating our unit-of-production depletion rates. Both proved and proved developed reserves estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense. Proved reserves are used where a property is acquired and proved developed reserves are used where a property is drilled and developed. In 2008, oil and gas and Syncrude depletion of \$1,340 million (before impairments) was recorded in depletion, depreciation, amortization and impairment expense. If our reserves estimates changed by 10%, our depletion, depreciation, amortization and impairment expense would have changed by approximately \$134 million, assuming no other changes to our reserves profiles.
- assessing, when necessary, our oil and gas assets for impairment. Estimated future undiscounted cash flows are determined using proved reserves. The critical estimates used to assess impairment, including the impact of changes in reserves estimates, are discussed below.

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

## Impairments

### Property, Plant and Equipment

We evaluate our long-lived assets (oil and gas properties, Syncrude and chemicals) for impairment if an adverse event or change occurs. Among other things, these might include falling oil and gas prices, a significant negative revision to our reserve estimates, changes in operating and capital costs, or significant or adverse political or regulatory changes. If one of these occurs, we assess estimated undiscounted future cash flows for affected properties to determine if they are impaired. If the undiscounted future cash flow for a property is less than

the carrying amount of that property, we estimate its fair value using a discounted cash flow model.

Cash flow estimates for our impairment assessments require assumptions about the following primary elements—future prices, reserves and discount rates. Our estimates of future prices are based on our assumptions of long-term prices and operating and development costs and require significant judgments about highly uncertain future events. Historically, oil and gas prices have exhibited significant volatility—over the last five years, prices for WTI and NYMEX gas have ranged from US\$32.20/bbl to US\$147.27/bbl and US\$4.20/mmbtu to US\$15.38/mmbtu, respectively. Our forecasts for oil and gas revenues are based on prices derived from a consensus of future price forecasts amongst industry analysts, our own assessments and existing future strip prices. Our estimates of discount rates include consideration of the marketplace and risk of the asset. Given the significant assumptions required and the possibility that actual conditions will differ, we consider the assessment of impairment to be a critical accounting estimate. A change in these estimates would impact all businesses with the exception of chemicals and energy marketing.

It is difficult to determine and assess how a decrease in proved reserves impacts our impairment tests. The relationship between our reserve estimate and the estimated undiscounted cash flows, and the nature of the property-by-property impairment test is complex. As a result, we are unable to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on our assessment of impairment.

## Goodwill

We test goodwill for impairment whenever an event or circumstance occurs that may reduce the fair value of a reporting unit below its carrying amount and at least annually. Our goodwill impairment test is a two-step process. First, the fair value of a reporting unit is compared with its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds the fair value, the second step is required. The second step allocates the fair value of the reporting unit to its underlying assets and liabilities, resulting in an implied fair value of goodwill. If the carrying amount of the reporting unit exceeds the implied fair value of that goodwill, an impairment loss equal to the excess is recorded in net income.

The process of assessing goodwill for impairment necessarily requires us to determine the fair values of our assets using one or more valuation techniques including present value calculations of estimated future cash flows. This process involves

making various assumptions and judgments about future commodity prices, future income, operating costs and discount rates. Changes in any of these assumptions or judgments could result in an impairment of all or a portion of goodwill.

### **Asset Retirement Obligations**

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

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

A change in any one of our assumptions could impact our asset retirement obligations, the carrying value of our property, plant and equipment and our net income.

### **Income Taxes**

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

### **Derivatives and Fair Value Measurements**

We enter into contracts to purchase and sell crude oil and natural gas and use derivative contracts, including futures, forwards, swaps and options, for hedging and trading purposes (collectively derivatives). We also use derivatives to manage commodity price risk and foreign currency risk for non-trading purposes.

The fair value of derivative contracts is estimated. Wherever possible, this estimate is based on quoted market prices, and if not available, on estimates from third-party brokers. We classify the fair value of our derivatives according to a three-level hierarchy based on the amount of observable inputs used to value the instruments. Inputs may be; (1) readily observable; (2) market corroborated; or (3) generally unobservable. We utilize valuation techniques that maximize the use of observable inputs wherever possible and minimize the use of unobservable inputs. Another significant assumption that we use in determining the fair value of derivatives is market data or assumptions that market participants would use when pricing the asset or liability, including assumptions about risk. Additionally, we utilize a mid-market pricing convention between bid and ask and then adjust our pricing to the ask price when we have a net open sell position and the bid price when we have a net open buy position. We incorporate the credit risk associated with counterparty default into our estimates of fair value.

Our assessment of the significance of a particular input to the fair value measurement may affect the valuation of fair value within the hierarchy. Also for derivative contracts, the time between inception and settlement of the contract may affect fair value. The actual settlement of derivatives could differ materially from the fair value recorded and could impact future operating results.

### **NEW ACCOUNTING PRONOUNCEMENTS**

#### **International Financial Reporting Standards Adoption Plan**

In February 2008, the AcSB confirmed that all Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards (IFRS) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. We are currently assessing the impact of the convergence of Canadian GAAP with IFRS on our results of operations, financial position and disclosures. A project team has been established to manage this transition and to ensure successful implementation within the required time frame.

The project team consists of dedicated personnel who have the experience and IFRS knowledge to ensure success within the required time frame. A steering committee comprised of senior management has been established for project oversight. The

steering committee has the responsibility to ensure the project is adequately planned in sufficient detail, appropriate resources are available, necessary milestones are established and project progress is properly monitored. These senior leaders are also responsible for internal controls over financial reporting and our disclosure controls and procedures.

We recognize that the changeover to IFRS has complex implications on a combination of accounting, IT and business systems, and that there are many aspects to IFRS that we are unfamiliar with. Consequently, we engaged a major accounting firm to provide training and education, and to advise and assist us with identifying accounting treatment differences between IFRS and Canadian GAAP. In addition, based on their previous conversion engagements, we expect our advisor to be able to create efficiencies in our conversion effort by sharing their experiences and informing us of best practices.

Our project consists of 5 phases: (i) Diagnostic; (ii) Design and Plan; (iii) Develop Solution; (iv) Implementation; and (v) Closeout. We are currently in the Design and Plan phase. During this phase, we are identifying differences between Canadian GAAP and IFRS, gathering information and financial data to assess the potential impacts of these differences, and making recommendations for IFRS accounting policy decisions. Discussion papers are being prepared to properly document the information gathered and support our rationale for our accounting policy recommendations. Factors such as financial and key performance indicator impacts, information technology and systems, internal control environment, treasury, human resources, and general business impacts are outlined in the papers.

Major accounting policy change decisions are expected to be evaluated in early 2009. Our oil and gas business follows successful efforts accounting as described in Note 1 of our consolidated financial statements. Our preliminary review of IFRS indicates that the majority of our existing oil and gas accounting policies are acceptable under IFRS. However, the analysis and comparison between our existing accounting policies and IFRS is complex. Our goal is to chose policies that most accurately reflect the underlying economic results of our operations and financial position within the IFRS framework.

Following completion of the Design and Plan stage, we will be involved with the Develop Solution and Implementation phases throughout the remainder of 2009 and into 2010. We will provide additional disclosures of the key elements of our plan and progress of the project as the information becomes available.

## Canadian Pronouncements

In February 2008, the AcSB issued Section 3064, *Goodwill and Intangible Assets* and amended Section 1000, *Financial Statement Concepts* clarifying the criteria for recognizing assets, intangible assets and internally developed intangible assets. Items that no longer meet the definition of an asset are no longer recognized with assets. The standard is effective for fiscal years beginning on or after October 1, 2008 and early adoption is permitted. We do not expect the adoption of this section to have a material impact on our results of operations and financial position.

In January 2009, the AcSB issued Section 1582, *Business Combinations*, which replaces former guidance on business combinations. Section 1582 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 2011, with earlier adoption permitted. We plan to adopt this standard prospectively effective January 1, 2009 and do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In January 2009, the AcSB issued Sections 1601, *Consolidated Financial Statements*, and 1602, *Non-controlling Interests*, which replaces existing guidance. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. These statements are effective on or after the beginning of the first annual reporting period beginning on or after January 2011, with earlier adoption permitted. We plan to adopt these standards prospectively effective January 1, 2009 and do not expect the adoption to have a material impact on our results of operations or financial position.

## US Pronouncements

In December 2007, FASB issued Statement 141 (revised), *Business Combinations*. Statement 141 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In December 2007, FASB issued Statement 160, *Non-controlling Interests In Consolidated Financial Statements*, an amendment of ARB No. 51. This statement clarifies that a non-controlling interest in a subsidiary should be reported as equity in the consolidated financial statements. This statement is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In March 2008, FASB issued Statement 161, *Disclosures about Derivative Instruments and Hedging Activities*, an amendment of FASB Statement 133. The statement requires qualitative disclosures about the objectives and strategies for using derivatives, quantitative data about the fair value of gains and losses on derivative contracts, and details of credit-risk-related contingent features in their hedged position. The statement also requires the disclosure of the location and amounts of derivative instruments in the financial statements. This statement is effective for fiscal years and interim periods beginning on or after November 15, 2008. We do not expect the adoption of this statement to materially impact our results of operations or financial position.

In December 2008, FASB issued FSP FAS 132 (R)-1, *Employers' Disclosures about Postretirement Benefit Plan Assets*. This position provides guidance on disclosures about plan assets of a defined benefit pension or other postretirement plans, effective for fiscal years ending after December 15, 2009. We do not expect the adoption of this statement to materially impact our results of operations or financial position.

In December 2008, the SEC issued Rule 33-8995 *Modernization of Oil and Gas Reporting*. These rules revise oil and gas reporting disclosure requirements and are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. These rules are effective for reports filed after January 1, 2010; earlier adoption is not permitted. We are currently evaluating the impact of these rules on our reserve estimates and disclosures.

## ITEM 7A. Quantitative and Qualitative Disclosures about Market Risk

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

## NON-TRADING Commodity Price Risk

Commodity price risk related to conventional and synthetic crude oil prices is our most significant market risk exposure. Crude oil and natural gas prices are sensitive to numerous worldwide factors, including the current global financial crisis, many of which are beyond our control, and are generally sold at contract or posted prices. Changes in world crude oil and natural gas prices may significantly affect our results of operations and cash generated from operating activities. Consequently, such prices also may affect the value of our oil and gas properties and our level of spending for exploration and development.

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

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

In 2008, WTI averaged US\$99.65/bbl, reaching a high of US\$147.27/bbl and a low of US\$32.40/bbl. Dated Brent, on which approximately 64% of our production is priced, averaged US\$96.99/bbl, reaching a high of US\$144.22/bbl and a low of US\$33.66/bbl. NYMEX natural gas prices averaged US\$8.90/ mmbtu in 2008, reaching a high of US\$13.69/mmbtu and a low of US\$5.21/mmbtu. Our sensitivities to commodity prices and the expected impact on our 2009 cash flow from operating activities and net income are as follows:

<i>(Cdn\$ millions)</i>	<b>Cash Flow</b>	<b>Net Income</b>
WTI—US\$1/bbl change above US\$60	50	44
WTI—US\$1/bbl change below US\$60	40	35
NYMEX Natural Gas—US\$0.50/mcf change	34	23

These sensitivities are based on our estimated 2009 oil and gas production and assume a Canadian/US dollar exchange rate of \$0.83. Our estimated oil and gas production range for 2009 is between 255,000 and 270,000 boe/d before royalties, of which approximately 16% is gas.

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

In 2008, we purchased Dated Brent put options to manage the commodity price risk exposure on a portion of our oil production in 2009. These put options have established an annual average Dated Brent floor price of US\$60/bbl on about 45,000 bbls/d of production.

### Foreign Currency Risk

A substantial portion of our activities are transacted in or referenced to US dollars including:

- sales of crude oil, natural gas and certain chemicals products;
- capital spending and expenses for our oil and gas, Syncrude and chemicals operations; and
- short-term and long-term borrowings.

The Canadian/US dollar exchange rate averaged \$0.94 in 2008, ranging from a low of \$0.77 to a high of \$1.03.

Our sensitivities to the US dollar and the expected impact of a one cent change on our 2009 cash flow from operating activities, net income, capital expenditures and long-term debt is as follows:

<i>(Cdn\$ millions)</i>	<b>Cash Flow</b>	<b>Net Income</b>	<b>Capital Expenditures</b>	<b>Long-term Debt</b>
<b>\$0.01 Change in US to Cdn</b>	36	18	23	50

Our sensitivities to changes in the Canadian/US dollar exchange rate are calculated based on projected revenues, expenses, capital expenditures and US-dollar denominated long-term debt for 2009. These estimates are based on a WTI price for crude oil ranging between US\$50/bbl and US\$65/bbl, a NYMEX natural gas price of US\$6.50/mmbtu and a Canadian/US dollar exchange rate of \$0.83.

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

Our chemicals operations are exposed to changes in the US-dollar exchange rate as part of their sales are denominated in US-dollars. Canexus periodically purchases US-dollar call options to reduce this exposure. As part of the technical conversion project, Canexus also has a contract in Japanese Yen. To manage these exposures, Canexus had the following outstanding option contracts at December 31, 2008.

- The right to sell US\$5 million monthly and purchase Canadian dollars at an exchange rate of US\$0.82 from January 1, 2009 to December 31, 2009;
- The right to sell US\$5 million monthly and purchase Canadian dollars at an exchange rate of US\$0.817 from January 1, 2009 to December 31, 2009; and
- A forward exchange contract to purchase 1.74 billion Japanese Yen (JPY) at a rate of 108.11 JPY per US dollar on May 20, 2009.

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

### Interest Rate Risk

We are exposed to fluctuations in interest rates on our floating-rate debt. To minimize our exposure to interest rate fluctuations, we occasionally use derivative instruments.

Our sensitivity to interest rates and the expected impact of a 1% change in interest rates on our 2009 cash flow from operating activities and net income is as follows:

<i>(Cdn\$ millions)</i>	<b>Cash Flow</b>	<b>Net Income</b>
<b>Interest Rates—1% change in rates</b>	12	9

Our sensitivity to changes in interest rates is based on 2009 estimated average floating rate debt of \$1.2 billion and a Canadian/US dollar exchange rate of \$0.83.

Our floating rate debt exposes us to changes in interest payments as interest rates fluctuate. To manage this exposure, we maintain a combination of fixed and floating rate borrowings and facilities. At December 31, 2008, fixed-rate borrowings comprised 78% (2007—91%) of our long-term debt at an effective average rate of 6.4% (2007—6.3%). During the year, we periodically borrow under our committed, unsecured, term credit facilities and at December 31, 2008, floating-rate debt comprised 22% (2007—9%) of our long-term debt at an effective average rate of 2.7% (2007—5.8%) ranging from a low of 1.0% to a high of 7.8% during 2008.

We had no interest rate swaps outstanding in 2008 or 2007.

## TRADING

### Commodity Price Risk

Our marketing business is focused on providing services to our customers and suppliers to meet their energy commodity needs. We market and trade physical energy commodities in selected regions of the globe including crude oil, natural gas, electricity and other commodities. We do this by buying and selling physical commodities, by acquiring and holding rights to physical transportation and storage assets for these commodities, and by building strong relationships with our customers and suppliers.

In order to manage the commodity and foreign exchange price risks that come from this physical business, we use financial derivative contracts including energy-related futures, forwards, swaps and options, as well as currency swaps or forwards.

We also seek to profit from our views on the future direction of energy commodity pricing relationships, primarily between different locations, time periods or qualities. We do this by holding open positions, where the terms of physical or financial contracts are not completely matched to offsetting positions. We may also carry exposures to the absolute change in commodity prices based on our market views or as a consequence of managing our physical and financial positions on a day to day basis.

The physical and financial marketing and trading activities we undertake expose us to the risk of loss (and provide the opportunity to profit) from a range of factors including:

- changes to the absolute level of commodity prices;
- changes in the prices of commodities at specific locations;
- changes in the relative level of nearer term prices to future prices;
- changes in the relative value of different qualities of a commodity;
- changes in the volatility of commodity prices;
- changes in the relationships between energy commodity prices and/or derivative instruments;
- changes in the operational costs of our physical transportation and storage contracts;
- physical or financial loss of physical product; and
- disputes over terms of deals and contracts.

In order to manage these risks we have risk management systems and processes including:

- regular reporting to the Board of Directors;
- regular reporting to the Risk Management Committee;
- oversight of activities by experienced commercial management;
- a separate Risk Management Office; and
- comprehensive policies, procedures and controls.

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

- changes in commodity prices are either normally or “T” (for natural gas since May 2006) distributed;
- price volatility remains stable; and
- price correlation relationships remain stable.

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

<i>(Cdn\$ millions)</i>	2008	2007	2006
<b>Value-at-Risk</b>			
Year End	25	26	26
High	40	38	33
Low	19	24	17
Average	30	30	23

If market shock occurred as in 2008, the key assumptions underlying our VaR estimate could be exceeded and the potential loss could be greater than our estimate. We perform stress tests on a regular basis to complement VaR and assess the impact of non-normal changes in prices on our positions.

Throughout the second half of 2008 and into 2009, we have been realigning our marketing strategies and positions to focus more on physical business which has been built around storage, blending and transportation. To this end, we are reducing our trading levels in an orderly fashion recognizing the challenging economic environment and we have reduced the overall size of our trading business to reduce volatility and focus on the physical side of our business. We are exiting trading positions that do not support our physical business and we are continuing to reduce trading exposures.

## CREDIT RISK

Credit risk affects both our trading and non-trading activities and is the risk of loss if counterparties do not fulfill their contractual obligations. Most of our credit exposures are with counterparties in the energy industry, including integrated oil companies, refiners and utilities and are subject to normal industry credit risk. Approximately 71% of our exposure is with these large energy companies. This concentration of risk within the energy industry is reduced because of our broad base of domestic and international counterparties. We take the following measures to reduce this risk:

- assess the financial strength of our counterparties through a formal credit process;
- limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;
- routinely monitor credit risk exposures, including sector, geographic and corporate concentrations of credit, and report these to our Risk Management Committee and the Finance Committee of the board;
- set credit limits based on rating agency credit ratings and internal assessments based on company and industry analysis;
- review counterparty credit limits regularly; and
- use standard agreements that allow for the netting of exposures associated with a single counterparty.

We believe these measures minimize our overall credit risk. However, there can be no assurance that these processes will protect us against all losses from non-performance. During 2008, we have taken the following specific actions for certain counterparties deemed to be at higher risk of non-performance:

- ceased trading activities;
- significantly reduced and, in some cases, revoked credit privileges;
- redirected business to i) exchanges or clearing houses; and ii) entities with physical-based operations;
- increased "set off" arrangements with counterparties; and
- increased collateral and margining requirements where possible.

At December 31, 2008, only one counterparty individually made up more than 10% of our credit exposure. This counterparty is a major integrated oil company with a strong investment grade rating. No other counterparties made up more than 5% of our credit exposure. In addition, the following table illustrates the composition of credit exposure by credit rating.

Credit Rating	2008	2007
A or Higher	65%	68%
BBB	29%	27%
Non investment Grade	6%	5%

Our maximum counterparty credit exposure at the balance sheet date consists primarily of the carrying amounts of non-derivative financial assets such as accounts receivable, as well as the fair value of derivative financial assets. In September, Lehman Brothers filed for bankruptcy protection and our exposure at the time was approximately \$39 million. This amount was written off, however, we continue to pursue recovery of these amounts. We also provided an additional \$15 million for credit risk with our counterparties. We are closely monitoring credit exposures. In addition, we incorporate the credit risk associated with counterparty default, as well as Nexen's own credit risk, into our estimates of fair value. We based our credit risk estimates, to the extent possible, on market observable inputs such as bond spreads.

## SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this report, including those appearing in *Items 1 and 2—Business and Properties* and *Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations*, constitute "forward-looking statements" (within the meaning of the United States *Private Securities Litigation Reform Act* of 1995, Section 21E of the United States *Securities Exchange Act of 1934*, as amended, and Section 27A of the United States *Securities Act of 1933*, 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, natural gas or chemicals prices;
- future production levels;

- future cost recovery oil revenues from our Yemen operations;
- future capital expenditures and their allocation to exploration and development activities;
- future earnings;
- future asset dispositions;
- future sources of funding for our capital program;
- future debt levels;
- availability of committed credit facilities;
- possible commerciality;
- development plans or capacity expansions;
- future ability to execute dispositions of assets or businesses;
- future 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 demand for chemical products;
- estimates on a per share basis;
- sales;
- future expenditures and future allowances relating to environmental matters;
- dates by which certain areas will be developed or will come on stream; and
- changes in any of the foregoing.

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

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 and chemical products;
- our ability to explore, develop, produce and transport crude oil and natural gas to markets;
- the results of exploration and development drilling and related activities;
- 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;

- renegotiations of contracts;
- results of litigation, arbitration or regulatory proceedings; and
- political uncertainty, including actions by terrorists, insurgent or other groups, or other armed conflict, including conflict between states.

These risks, uncertainties and other factors and their possible impact are discussed more fully in the section, titled *Risk Factors* in Item 1A and *Quantitative and Qualitative Disclosures about Market Risk* in Item 7A. 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 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. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

## **SPECIAL NOTE TO CANADIAN INVESTORS**

Nexen is an SEC registrant and a voluntary Form 10-K (and related forms) filer. Therefore, our reserves estimates and securities regulatory disclosures follow SEC requirements. In Canada, *National Instrument 51-101—Standards of Disclosure for Oil and Gas Activities* (NI 51-101) prescribes that Canadian companies follow certain standards for the preparation and disclosure of reserves and related information. Nexen reserves disclosures are made in reliance upon exemptions granted to Nexen by Canadian securities regulators from certain requirements of NI 51-101 which permits us to:

- prepare our reserves estimates and related disclosures in accordance with SEC disclosure requirements, generally accepted industry practices in the US and the standards of the *Canadian Oil and Gas Evaluation Handbook* (COGE Handbook) modified to reflect SEC requirements;
- substitute those SEC disclosures for much of the annual disclosure required by NI 51-101; and

- rely upon internally-generated reserves estimates and the *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein*, included in the Supplementary Financial Information, without the requirement to have those estimates evaluated or audited by independent qualified reserves evaluators.

As a result of these exemptions, Nexen's disclosures may differ from other Canadian companies and Canadian investors should note the following fundamental differences in reserves estimates and related disclosures contained in the Form 10-K:

- SEC registrants apply SEC reserves definitions and prepare their proved reserves estimates in accordance with SEC requirements and generally accepted industry practices in the US whereas NI 51-101 requires adherence to the definitions and standards promulgated by the COGE Handbook;
- the SEC mandates disclosure of proved reserves and the Standardized Measure of Discounted Future Net Cash Flows and Changes Therein calculated using year-end constant prices and costs only whereas NI 51-101 requires disclosure of reserves and related future net revenues using forecast prices;
- the SEC mandates disclosure of proved and proved developed reserves by geographic region only whereas NI 51-101 requires disclosure of more reserve categories and product types;
- the SEC does not prescribe the nature of the information required in connection with proved undeveloped reserves and future development costs whereas NI 51-101 requires certain detailed information regarding proved undeveloped reserves, related development plans and future development costs;
- the SEC does not require disclosure of finding and development (F&D) costs per boe of proved reserves additions whereas NI 51-101 requires that various F&D costs per boe be disclosed. NI 51-101 requires that F&D costs be calculated by dividing the aggregate of exploration and development costs incurred in the current year and the change in estimated future development costs relating to proved reserves by the additions to proved reserves in the current year. However, this will generally not reflect full cycle finding and development costs related to reserve additions for the year;
- the SEC leaves the engagement of independent qualified reserves evaluators to the discretion of a company's Board of Directors whereas NI 51-101 requires issuers to engage such evaluators and to file their reports;
- the SEC does not consider the upgrading component of our integrated oil sands project at Long Lake as an oil and gas

activity, and therefore permits recognition of bitumen reserves only. NI 51-101 specifically includes such activity as an oil and gas activity and recognizes synthetic oil as a product type, and therefore permits recognition of synthetic reserves. At year end, we have recognized 285 million barrels before royalties of proved bitumen reserves (282 million barrels after royalties) under SEC requirements, whereas under NI 51-101 we would have recognized 233 million barrels before royalties of proved synthetic reserves (231 million barrels after royalties);

- the SEC considers our Syncrude operation as a mining activity rather than an oil and gas activity, and therefore does not permit related reserves to be included with oil and gas reserves. NI 51-101 specifically includes such activity as an oil and gas activity and recognizes synthetic oil as a product type, and therefore permits them to be included with oil and gas reserves. We have provided a separate table showing our share of the Syncrude proved reserves as well as the additional disclosures relating to mining activities required by SEC requirements; and
- any reserves data in this document reflects our estimates of reserves. While we obtain an independent assessment of a portion of our reserves estimates, no independent qualified reserves evaluator or auditor was involved in the preparation of the reserves data disclosed in this Form 10-K.

The foregoing is a general description of the principal differences only.

Please note that the differences between SEC requirements and NI 51-101 may be material.

NI 51-101 requires that we make the following disclosures:

- we use oil equivalents (boe) to express quantities of natural gas and crude oil in a common unit. A conversion ratio of 6 mcf of natural gas to 1 barrel of oil is used. Boe may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead; and
- because reserves data are based on judgments regarding future events actual results will vary and the variations may be material. Variations as a result of future events are expected to be consistent with the fact that reserves are categorized according to the probability of their recovery.