



## MD&A

Our 2006 accomplishments position us for an exciting 2007 as we plan to ramp up production at Buzzard, bring Long Lake on stream, evaluate our recent discoveries and continue exploring.

## 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 21 to the Consolidated Financial Statements. The date of this discussion is February 9, 2007.

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.

Note: Canadian investors should read the Special Note to Canadian Investors on page 81 which highlights differences between our reserve estimates and related disclosures that are otherwise required by Canadian regulatory authorities.

	Page
<b>Executive Summary</b>	39
<b>Capital Investment</b>	40
<b>Financial Results</b>	
Year-to-Year Change in Net Income	44
Oil & Gas and Syncrude	
Production	45
Commodity Prices	48
Operating Expenses	51
Depreciation, Depletion, Amortization and Impairment	52
Exploration Expense	54
Oil & Gas and Syncrude Netbacks	56
Energy Marketing	57
Chemicals	60
Corporate Expenses	61
<b>Outlook for 2007</b>	64
<b>Liquidity and Capital Resources</b>	65
<b>Critical Accounting Estimates</b>	71
<b>New Accounting Pronouncements</b>	74
<b>Quantitative and Qualitative Disclosures about Market Risk</b>	77

**EXECUTIVE SUMMARY**

(Cdn\$ millions)	2006	2005	2004
Net Income	601	1,140	793
Earnings per Common Share, Basic (\$/share)	2.29	4.38	3.08
Cash Flow from Operating Activities	2,374	2,143	1,606
Production before Royalties (mboe/d) <sup>1</sup>	212	242	250
Production after Royalties (mboe/d)	156	173	174
Capital Investment, including Acquisitions	3,408	2,638	4,264
Net Debt <sup>2</sup>	4,730	3,639	4,285
Average Foreign Exchange Rate (Canadian to US dollar)	0.88	0.83	0.77
Proved Oil and Gas Reserves before Royalties (mmboe) <sup>3</sup>	725	468	542
Proved Oil and Gas Reserves after Royalties (mmboe) <sup>3</sup>	637	393	451
Proved Syncrude Reserves before Royalties (mmboe) <sup>3</sup>	324	318	301
Proved Syncrude Reserves after Royalties (mmboe) <sup>3</sup>	274	264	255

**Notes:**

- <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.
- <sup>3</sup> Includes developed and undeveloped proved reserves as at December 31.

Strong commodity prices and record results from our energy marketing group contributed to net income and cash flow from operating activities. WTI reached new trading highs during the year and our realized oil and gas price was \$62.92/boe, 9% above 2005. The marketing group contributed record results, generating value from the optimization of storage and transportation capacity, as well as financially trading price differences caused by location, product quality and time. At the beginning of the year, the UK government increased the supplementary tax on oil and gas activities in the North Sea. As a result, we recorded \$277 million of future income tax expense. Our 2006 income also included \$151 million of expense in connection with our Block 51 arbitration. Last year, our net income included gains of \$225 million from the sale of Canadian oil and gas properties and a gain of \$193 million on the sale of a portion of our interest in our chemicals business.

Our combined oil & gas and Syncrude production was lower than 2005 levels as we continue to transition from maturing production in Yemen and Canada to new higher-return production in 2007, primarily in the North Sea and the Gulf of Mexico. The 2005 sale of Canadian conventional oil and gas assets reduced our 2006 volumes by 10,700 boe/d before royalties (8,100 boe/d after royalties) as compared to last year. As expected, our Masila assets continued to mature and production declined 16,800 boe/d (7,600 boe/d after royalties). Our ongoing investment in Masila is to maximize the recovery of the remaining reserves before our licence expires in 2011. With Buzzard on stream in early January 2007, our 2007

net production is expected to grow 50% to average between 230,000 boe/d and 260,000 boe/d, after royalties, and between 275,000 boe/d and 305,000 boe/d, before royalties.

In 2006, our largest annual capital program was focused on our major development projects at Buzzard and at Long Lake. Development of Buzzard in the North Sea was completed during the year and the field began producing on January 7, 2007. Peak production rates of 85,000 boe/d, net to us, are expected by mid 2007. At Long Lake, we invested over \$1 billion on the SAGD component of the project and on construction of the upgrader. We expect steam injection to begin at the end of the first quarter of 2007, with upgrader start up scheduled for late 2007. At its peak, we expect our share of synthetic crude oil from phase 1 of Long Lake to be 30,000 bbls/d. At Syncrude, the Stage 3 expansion was brought on stream in 2006, adding 8,000 bbls/d of production capacity. Late in the year, we completed an additional development well at Aspen in the Gulf of Mexico, and we expect 2007 Aspen production to average between 15,000 and 20,000 boe/d.

**Cash Flow from Operating Activities (Cdn\$ millions)**

2006	2,374
2005	2,143
2004	1,606

Our 2006 exploration program was focused on drilling 20 wells, primarily in the Gulf of Mexico and the North Sea. We had successful results from Alaminos Canyon Block 856 (Great White West) and Ringo in the Gulf of Mexico, and Golden Eagle in the North Sea.

Our net debt increased from 2005 as a result of our investment in capital projects, primarily at Buzzard and Long Lake. We drew upon our committed term credit facilities during the year as our capital spending exceeded our cash flow by approximately \$1 billion.

Throughout 2006, the Canadian dollar continued to strengthen relative to the US dollar. Our sales revenue is denominated in or referenced to US dollars. As a result, our revenues decline as the US dollar weakens. On the other hand, our US-dollar capital spending and operating costs are lower when translated to Canadian dollars. Overall, the weaker US dollar reduced our 2006 cash flow from operating activities and net income by \$223 million and \$98 million, respectively.

During 2006, our proved oil and gas and Syncrude reserves additions replaced more than 400% of our oil and gas and Syncrude production (500% after royalties) as shown in the following table:

(mmboe)	Before Royalties	After Royalties
<b>Production</b>		
Oil and Gas	71	51
Syncrude	7	6
<b>Total</b>	<b>78</b>	<b>57</b>
<b>Extensions, Discoveries and Revisions</b>		
Oil and Gas	328	295
Syncrude	13	16
<b>Total</b>	<b>341</b>	<b>311</b>

The majority of our 2006 additions came from our development projects at Long Lake in the Athabasca oil sands, Ettrick in the North Sea and Usan, offshore West Africa. We included 246 mmboe of bitumen (219 after royalties) at Long Lake as a result of strong year-end bitumen prices and lower natural gas costs. The Ettrick development was sanctioned

during the year, contributing 18 mmboe of proved reserves (18 after royalties). At Usan, offshore West Africa, we added 30 mmboe of proved reserves (25 after royalties). Reserves were also added from ongoing activities in Canada, the Gulf of Mexico and the North Sea.

## CAPITAL INVESTMENT

(Cdn\$ millions)	Estimated 2007	2006	2005
Major Development	1,000	1,849	1,550
Early Stage Development	400	123	54
New Growth Exploration	700	491	456
Core Asset Development	700	748	524
Total Oil & Gas and Syncrude	2,800	3,211	2,584
Marketing, Corporate, Chemicals and Other	100	197	54
<b>Total Capital</b>	<b>2,900</b>	<b>3,408</b>	<b>2,638</b>

Our strategy and capital programs are focused on growing long-term value for our shareholders. 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; and
- exploration projects for longer-term growth.

As conventional basins in North America mature, we have been transitioning our operations toward less mature basins and unconventional resources. Our key focus areas include the North Sea, Athabasca oil sands, Canadian coalbed methane, Gulf of Mexico, offshore West Africa and the Middle East—

areas we believe have attractive fiscal terms and significant remaining opportunity, and where we have some competitive advantage.

In 2006, we invested more than \$3.4 billion in capital expenditures, mostly in multi-year development projects and long cycle-time exploration. In 2007, we plan to invest \$2.8 billion in our oil and gas and Syncrude assets. About 34% of this is focused on multi-year development projects, 28% on core assets to sustain production and provide cash flow, and 24% on drilling high-impact exploration wells and building our acreage position. The rest will be spent on early stage development activities.

### 2006 Investment Program

(Cdn\$ millions)	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas					
Synthetic (mainly Long Lake)	1,050	74	45	–	1,169
United Kingdom	552	14	62	31	659
Yemen	–	–	37	145	182
United States	31	–	177	387	595
Canada	167	15	118	140	440
Other Countries	–	20	52	8	80
Syncrude	49	–	–	37	86
	<b>1,849</b>	<b>123</b>	<b>491</b>	<b>748</b>	<b>3,211</b>
Marketing, Corporate and Other	–	–	–	197	197
<b>Total Capital</b>	<b>1,849</b>	<b>123</b>	<b>491</b>	<b>945</b>	<b>3,408</b>
As a % of Total Capital	54%	4%	14%	28%	100%

### 2007 Estimated Capital

(Cdn\$ millions)	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas					
Synthetic (mainly Long Lake)	500	170	–	–	670
United Kingdom	300	–	125	200	625
Yemen	–	–	50	100	150
United States	–	60	325	200	585
Canada	200	–	50	150	400
Other Countries	–	170	150	–	320
Syncrude	–	–	–	50	50
	<b>1,000</b>	<b>400</b>	<b>700</b>	<b>700</b>	<b>2,800</b>
Marketing, Corporate and Other	–	–	–	100	100
<b>Total Capital</b>	<b>1,000</b>	<b>400</b>	<b>700</b>	<b>800</b>	<b>2,900</b>
As a % of Total Capital	34%	14%	24%	28%	100%

2007 Estimated Capital

- Major Development (34%)
- Early Stage Development (14%)
- New Growth Exploration (24%)
- Core Asset Development (28%)



**Major and Early Stage Development Projects**

Approximately 58% of our 2006 capital was directed towards early stage and major development projects including Buzzard, Long Lake, Syncrude Stage 3 and CBM.

**Synthetic**

In 2006, we invested approximately \$1.2 billion to develop our insitu oil sands resource. This included approximately \$1.1 billion invested at our first phase of Long Lake. The SAGD facilities are in the final stages of commissioning and start up and we expect steam injection to commence at the end of the first quarter of 2007, with bitumen production rates ramping up to peak rates over a 12 to 24 month period. Upgrader module fabrication is largely complete and over 95% of the modules are on site. Construction of the upgrader is approximately 80% complete and start up is scheduled for late 2007. Production capacity for the first phase of Long Lake is approximately 60,000 bbls/d (30,000 bbls/d net to us) of premium synthetic crude which we expect to reach by late 2008 or early 2009.

**We have a number of major development projects at various stages of completion.**

We are planning to increase synthetic crude oil production to 240,000 bbls/d (120,000 bbl/s net to us) over the next decade. We plan to sequentially develop our oil sands leases with additional 60,000 bbls/d (30,000 bbls/d net to us) phases using the same technology and design as Long Lake phase 1. We are currently progressing phase 2 development. We have completed seismic and core hole drilling programs and we have ordered several major vessels.

**United Kingdom**

At Buzzard, we installed the utilities and production topsides, drilled the initial development wells and completed hook-ups and project commissioning. Buzzard came on stream in early January 2007 and production is ramping up. The facilities have the capacity to process up to 200,000 bbls/d of oil and 60 mmcf/d of gas, including the removal of hydrogen sulphide. Based upon recent drilling results, we have experienced more well-to-well variability in the concentration of hydrogen sulphide than previously seen. We expect existing equipment and processes will allow us to manage this variability for at least the first two or three years of production. As we continue to produce and acquire reservoir information, we will determine whether additional equipment will ultimately be required. We have a 43.2% interest in Buzzard and operate the project.

Elsewhere in the North Sea, we are progressing the development of the Ettrick field. Production at Ettrick is expected to commence in the first half of 2008, with our share reaching approximately 16,000 boe/d. Development is approximately 30% complete and includes drilling three production wells tied back to a floating production, storage and off-loading vessel. We have an 80% interest in Ettrick.

**Canada**

In Canada, we are developing the first commercial CBM project from Mannville coals in the Fort Assiniboine area of Alberta. In 2006, we invested \$237 million in exploration and development activities on our CBM lands, of which \$181 million was associated with development. We plan to increase our CBM production to at least 150 mmcf/d by 2011.

During the year, we acquired over 100 sections of land in an emerging shale gas play in western Canada. We plan to initiate a drilling and evaluation program in 2007 to demonstrate the feasibility of this opportunity.

### Other Countries

On Block OPL-222, offshore West Africa, Nigerian authorities have provisionally approved the Usan Field Development Plan. Basic engineering of the facilities is complete and tendering of contracts for all major components is proceeding. The development plan includes a floating production, storage and off-loading vessel with storage capacity of two million barrels, capable of handling peak production rates of 160,000 bbls/d of oil. We expect the Usan development to be formally sanctioned in 2007, with first production as early as 2010. We have a 20% interest in the exploration and development of this block.

### Syncrude

At Syncrude, we completed the Stage 3 expansion during the year. Start up was initially delayed by the emission of odours from the flue gas desulphurizer plant but modifications to eliminate the odours were completed and the expansion started up in late August. The Stage 3 expansion increases our production capacity by 8,000 bbls/d.

### New Growth Exploration

We invested approximately 14% of our 2006 capital in new growth exploration, including seismic data acquisition. We had exploration success in the Gulf of Mexico at Alaminos Canyon Block 856 (Great White West) and Ringo, and at Golden Eagle in the UK North Sea.

At Alaminos Canyon 856, we are evaluating development options following a two-well exploration drilling program earlier in the year. This block is located approximately 240 miles south of Houston and is immediately west of the Great White discovery. We have a 30% interest in this discovery.

At Ringo, we are evaluating a sub-sea tie-back to nearby facilities, which could be on stream in late 2008. We have a 50% interest in this discovery.

We recently completed drilling operations at our Golden Eagle prospect in the UK North Sea. The discovery well was drilled to a depth of approximately 7,500 feet and encountered hydrocarbons. A successful sidetrack well was drilled to appraise the accumulation and we are currently evaluating development options. We have a 34% operated interest in Golden Eagle.

---

### Our exploration program continues to deliver results with new finds in the Gulf of Mexico and North Sea.

---

In 2006, we participated in the Norwegian exploration bid round and were recently awarded four licenses. The licenses are in water depths from 1,000 to 1,300 feet and are located between 30 and 100 miles offshore Norway, situated close to existing infrastructure. In 2007, we plan to invest in additional seismic and geological studies in this region.

### Core Asset Development

We direct our capital investment in our maturing assets to extract maximum value over the remaining life of the assets. In the Gulf of Mexico, we began producing from an additional development well at Aspen in late December. Based on results from this well, we see further opportunities in the Aspen field and are currently sidetracking one of our existing Aspen wells to exploit deeper sands. We have a 100% interest in Aspen.

During the year, we commenced power production from our Soderglen 70 megawatt wind farm in southern Alberta. The wind farm comprises 47 wind towers, each with a 1.5 megawatt turbine. We have a 50% interest in this project.

**FINANCIAL RESULTS****Year-to-Year Change in Net Income**

(Cdn\$ millions)	<b>2006 vs 2005</b>	<b>2005 vs 2004</b>
<b>Net Income for 2005 and 2004 <sup>1</sup></b>	<b>1,140</b>	<b>793</b>
Favourable (unfavourable) variances: <sup>2</sup>		
Production Volumes, After Royalties		
Crude Oil	(245)	39
Natural Gas	(55)	(55)
Change in Crude Oil Inventory	(74)	4
Total Volume Variance	(374)	(12)
Realized Commodity Prices		
Crude Oil	325	648
Natural Gas	(133)	165
Total Price Variance	192	813
Oil and Gas Operating Expense		
Conventional	13	(64)
Syncrude	(35)	(27)
Total Operating Expense Variance	(22)	(91)
Depreciation, Depletion, Amortization and Impairment		
Oil & Gas and Syncrude	(48)	(308)
Other	4	(19)
Total Depreciation, Depletion, Amortization and Impairment Variance	(44)	(327)
Exploration Expense	(111)	(5)
Energy Marketing Contribution	336	49
Chemicals Contribution	(12)	31
General and Administrative Expense	254	(510)
Interest Expense	44	46
Current Income Taxes	(29)	(91)
Future Income Taxes	(549)	353
Other		
Block 51 Arbitration	(151)	-
Business Interruption Insurance Proceeds	152	(8)
Gains from Divestiture Programs	(418)	418
Increase (Decrease) in Fair Value of Crude Oil Put Options	185	(252)
Other	8	(67)
<b>Net Income for 2006 and 2005 <sup>1</sup></b>	<b>601</b>	<b>1,140</b>

## Notes:

<sup>1</sup> 2005 and 2004 includes results of discontinued operations (see Note 14 to our Consolidated Financial Statements).

<sup>2</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**

	2006		2005		2004	
	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> (mbbls/d)						
Yemen	92.9	51.8	112.7	60.6	107.3	53.5
Canada <sup>2</sup>	20.0	15.8	29.2	22.6	36.2	28.2
United States	17.0	15.0	22.2	19.6	30.0	26.5
United Kingdom	16.9	16.9	12.6	12.6	1.5	1.5
Australia <sup>3</sup>	–	–	–	–	2.7	2.5
Other Countries	6.3	5.7	5.6	5.1	5.3	4.7
Syncrude (mbbls/d) <sup>4</sup>	18.7	16.9	15.5	15.3	17.2	16.6
	171.8	122.1	197.8	135.8	200.2	133.5
<b>Natural Gas</b> (mmcf/d)						
Canada <sup>2</sup>	108	91	124	101	146	115
United States	111	94	116	99	148	126
United Kingdom	20	20	23	23	3	3
	239	205	263	223	297	244
<b>Total</b> (mboe/d)	<b>212</b>	<b>156</b>	<b>242</b>	<b>173</b>	<b>250</b>	<b>174</b>

## Notes:

- <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> Includes the following production from discontinued operations. See Note 14 to our Consolidated Financial Statements.

	2006	2005	2004
<b>Before Royalties</b>			
Oil and Liquids (mbbls/d)	–	6.7	11.7
Natural Gas (mmcf/d)	–	24	47
<b>After Royalties</b>			
Oil and Liquids (mbbls/d)	–	5.3	9.0
Natural Gas (mmcf/d)	–	17	33

- <sup>3</sup> Comprises production from discontinued operations. See Note 14 to our Consolidated Financial Statements.
- <sup>4</sup> Considered a mining operation for US reporting purposes.

**2006 vs 2005—Lower production decreased net income by \$374 million**

Production before royalties decreased 12% from 2005, while production after royalties decreased 10%. Our 2006 production excludes volumes from our Canadian oil and

gas properties that were sold in the third quarter of 2005. Removing the impact of these property dispositions, production before and after royalties declined 8% and 5%, respectively.

The following table summarizes our production changes year over year:

(mboe/d)	Before Royalties	After Royalties
2005 Production	242	173
Canada—Disposition of Properties	(11)	(8)
	231	165
<b>Production changes</b>		
Yemen	(20)	(9)
Canada	(1)	(1)
United States	(6)	(5)
United Kingdom	4	4
Colombia	1	1
Syncrude	3	1
<b>2006 Production</b>	<b>212</b>	<b>156</b>

In 2007, we expect to grow our annual production rate after royalties approximately 50% compared to 2006 to between 230,000 and 260,000 boe/d after royalties (275,000 and 305,000 boe/d before royalties). Increases are expected to come from Buzzard in the North Sea (which commenced production January 7, 2007), from the Gulf of Mexico and a full year of production from the Stage 3 expansion at Syncrude. Also, steam injection at Long Lake is expected to begin at the end of the first quarter in 2007, with bitumen production ramping up until the upgrader is scheduled to commence synthetic crude oil production late in 2007. Anticipated field declines in Yemen will partially offset these expected increases.

---

**Our production after royalties is expected to grow approximately 50% in 2007, with incremental volumes from Buzzard, the Gulf of Mexico, Syncrude Stage 3 and Long Lake.**

---

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

#### Yemen

Yemen production decreased 18% from 2005. Production from Masila decreased 19% reflecting the maturity of the field and the impact of a reduced development drilling program. In 2006, we drilled 28 development wells, eight fewer than in 2005. Strong initial rates from new wells, combined with well optimizations, helped to minimize expected production declines. Base declines at Masila are expected to continue as we maximize recovery of the remaining reserves on the block prior to expiry of our license in 2011. We plan to drill 14 development wells and continue our well optimization program in 2007.

On Block 51, production from the East Al Hajr field declined 12%. In the first quarter of 2006, we commissioned the permanent central processing facilities on the block. Lower than expected initial rates on new wells and higher than anticipated decline rates contributed to the decrease from 2005. During the year, we drilled 24 development wells and nine development wells are planned for 2007.

We expect our share of total production from Yemen to average between 60,000 and 75,000 bbls/d in 2007.

#### Canada

Production in Canada decreased 24% from the previous year, primarily as a result of the sale of conventional oil and gas properties in Alberta, British Columbia and Saskatchewan. Removing the effect of the dispositions, production decreased 3% from 2005. Natural field declines of 7,600 boe/d were offset by capital investment in our heavy oil and natural gas assets, contributing 5,500 boe/d in new production. Gas production is increasing at our coalbed methane projects in Alberta as existing wells continue to de-water and we bring more wells on stream. In 2007, we expect to drill 165 infill wells, continue optimization activities on our conventional assets and work on developing new technologies to increase recoveries on our heavy oil properties.

We expect 2007 production to average between 45,000 and 50,000 boe/d in Canada with the commencement of production of premium synthetic crude oil at Long Lake and additional coalbed methane volumes.

#### United States

Gulf of Mexico production declined 14%, or about 6,000 boe/d from 2005. Lower production from Aspen due to natural declines contributed approximately 5,400 boe/d of the decrease. An additional Aspen development well was brought on stream in December 2006. This well was expected to come on stream earlier in the year but damage to the drilling rig from a work-boat accident delayed completion of the well. We are currently side-tracking one of the wells and expect it to be on stream by mid 2007. In 2007, we expect production from the Aspen field to average between 15,000 and 20,000 boe/d. Gunnison production remained strong, accounting for 30% of our production from the Gulf of Mexico. Development of the Dawson Deep discovery was completed and tied-back to our Gunnison SPAR in July. The Wrigley development was delayed by the tight rig market in the Gulf, but completion is progressing and the development is expected to come on stream in the first half of 2007, with production rates anticipated of 3,200 boe/d.

The effects of Hurricanes Katrina and Rita continued to be felt in 2006 as we slowly restored production from fields shut-in due to damage received in 2005. Production from Vermilion 321 was restored in September 2006. At year end, Vermilion 340 remains shut-in from damage to the sub-surface pipeline system. This production was restored in early 2007 (400 boe/d). During the year, we received \$80 million of business interruption insurance proceeds related to the 2005 hurricanes.

In 2007, we expect production to average between 45,000 and 55,000 boe/d in the Gulf of Mexico.

#### United Kingdom

Production in the UK increased 23%, or 3,800 boe/d from 2005, primarily as a result of less downtime on the Scott platform and new production from our non-operated Farragon field. In 2005, our production was reduced by two generator failures on the Scott platform. During 2006, we received \$74 million in business interruption proceeds related to these failures. Our 2006 production was lower than we expected as planned maintenance work on the Scott platform flare tip took longer than anticipated and operating capacity was reduced by maintenance activities on the SAGE export pipeline.

---

**With Buzzard on stream, we expect UK production to average between 90,000 and 100,00 boe/d in 2007.**

---

Final commissioning of the facilities at Buzzard was delayed by inclement weather in the North Sea late in the year. Buzzard began production on January 7, 2007. The delay has no impact on our ramp-up plans and peak production of 85,000 boe/d is expected to be achieved in the second quarter of 2007.

In 2007, we plan to drill and complete eight production and three injection wells at Buzzard and three development wells in the Scott/Telford area. We expect our total year production from our North Sea assets to average between 90,000 and 100,000 boe/d in 2007. This compares to the 19,000 boe/d these assets produced when we purchased them in late 2004.

#### Other Countries

Production from the Guando field in Colombia was consistent with 2005. We maintained production rates from two infill drilling programs, bringing 15 additional wells on stream during the year. We expect to maintain production rates in Colombia in 2007.

#### Syncrude

At Syncrude, production increased 21% from 2005, but was lower than expected. The start-up of the Stage 3 expansion was delayed by emission of odours from the flue gas desulphurizer plant. Production from the Stage 3 expansion began in early May and was approaching design capacity rates prior to shutting in as a result of the odours. Modifications to eliminate the problem were completed during the summer and the facilities were restarted in late August. Late in the year, a turnaround on coker 8-2 reduced production by approximately 6,000 bbls/d. The turnaround was completed early in 2007.

Strong realized prices on production have enabled us to fully recover capital costs at Syncrude including costs associated with the Stage 3 expansion. Consequently, our Syncrude royalty in 2006 increased from a 1% gross revenue royalty to a 25% net revenue royalty. As a result of the increased royalty rate, we receive lower net production relative to our working interest production volumes.

In 2007, we expect our total-year production from Syncrude to average between 20,000 and 25,000 bbls/d.

#### 2005 vs 2004—Lower production decreased net income by \$12 million

Production before royalties declined 3% during 2005, while production after royalties remained consistent with 2004 levels. New royalty-free production from the UK North Sea partially offset the sale of higher-royalty production from Canada. We sold Canadian production during 2005 to reduce debt that financed our acquisition of offshore oil and gas assets in the North Sea. Production was lower as a result of hurricane activity in the Gulf of Mexico in the second half of 2005. Removing the impact of the Canadian asset sales and the lost volumes attributable to Hurricanes Katrina and Rita, our 2005 production before royalties would have increased 3% from 2004.

## Commodity Prices

	2006	2005	2004
<b>Crude Oil</b>			
West Texas Intermediate (WTI) (US\$/bbl)	66.22	56.58	41.40
Differentials <sup>1</sup> (US\$/bbl)			
Heavy Oil - LLK	21.79	20.82	13.53
MARS	7.34	6.59	6.15
Masila	3.00	5.71	4.84
Dated Brent	1.08	2.20	–
Producing Assets (Cdn\$/bbl)			
Yemen	71.57	62.07	47.59
Canada	42.79	40.51	36.60
United States	65.80	57.63	46.60
United Kingdom	71.19	60.55	46.81
Australia	–	–	51.22
Other Countries	66.09	59.96	43.07
Syncrude	72.32	71.00	52.80
Corporate Average (Cdn\$/bbl)	67.50	58.98	45.90
<b>Natural Gas</b>			
New York Mercantile Exchange (US\$/mmbtu)	6.99	8.99	6.19
AECO (Cdn\$/mcf)	6.62	8.04	6.44
Producing Assets (Cdn\$/mcf)			
Canada	6.49	7.51	5.76
United States	7.86	10.56	7.89
United Kingdom	7.43	7.86	8.28
Corporate Average (Cdn\$/mcf)	7.18	8.89	6.85
<b>Nexen's Average Realized Oil and Gas Price</b> (Cdn\$/boe)	<b>62.92</b>	<b>57.97</b>	<b>44.94</b>
Average Foreign Exchange Rate—Canadian to US Dollar	0.8818	0.8253	0.7683

Note:

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

### 2006 vs 2005—Higher realized prices increased net income \$192 million

Average WTI was 17% higher from the prior year, increasing our average realized crude oil price 14% to \$67.50/bbl. Our realized natural gas price fell 19% from 2005, while NYMEX decreased 22% in the same period. The full impact of the increase in WTI was not reflected in our higher realized

crude oil price as the Canadian dollar strengthened relative to the US dollar. The impact of the weaker US dollar was offset by narrower crude oil differentials. The weaker US dollar reduced net sales by approximately \$250 million, and reduced our realized crude oil and natural gas prices by approximately \$4.85/bbl and \$0.50/mcf, respectively as compared to 2005.

### Crude Oil Reference Prices

Crude oil prices remained strong for most of 2006, with WTI reaching new highs in July before finishing the year at US\$61.05/bbl, roughly where it began. WTI traded at an average of US\$66.22/bbl for the year, with a trading range of between US\$54.86/bbl and US\$78.40/bbl, where it peaked on July 14. The steady decline in crude prices from August to the end of the year was largely driven by warm weather, above average crude oil inventories, concerns over the US economy, the perceived reduction of geopolitical tensions in the Middle East and institution-led sell offs in the crude oil markets.

Weather has become an increasingly significant factor in the pricing of crude oil. In North America, a mild 2005/2006 winter followed by an uneventful hurricane season in the Gulf of Mexico and a forecast for a warmer than normal 2006/2007 winter season due to the warming effect of El Nino have put downward pressure on prices. The resulting reduced demand has helped push crude oil inventories to levels higher than the five-year average. In addition, concerns over a slowdown in the US economy due to the weakening of the US housing market have depressed crude oil prices further.

---

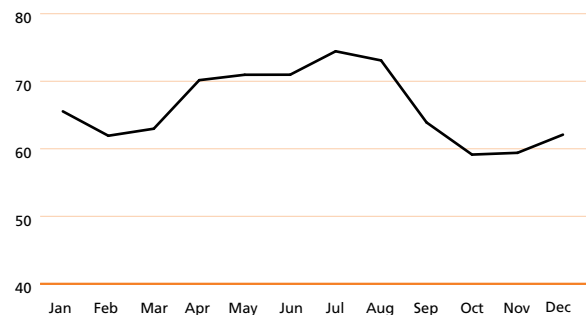
**WTI reached record highs during 2006, increasing our realized crude oil prices.**

---

Geopolitical events were a dominant theme through the first eight months of the year. Tensions in the Middle East as a result of Iran's uranium enrichment program, on-going violence in Iraq, fighting between Israel and Hezbollah militants in Lebanon, supply outages in Nigeria caused by continued violence and the nationalization of Venezuela's energy industry contributed to increased prices and greater market volatility. Towards the end of the year, however, geopolitical tensions have been discounted by the market following an end to the conflict in Lebanon and doubts the US will move against Iran.

A number of oil and gas producers have put option price protection programs in place at WTI strike prices ranging from US\$45 to US\$60/bbl. With falling crude oil prices, these programs get closer to being "in the money". This caused a sell-off in the crude oil markets by various institutions that wrote these options as they attempted to manage their option exposures. This sell-off contributed to the downward pressure on crude prices.

2006 WTI Monthly Average Oil Price (US\$/bbl)



To mitigate the bearish sentiments for crude oil, OPEC has shown a commitment to its US\$50 – \$55/bbl basket price by agreeing to reduce production by 1.2 million barrels a day from November 1 and by a further 500,000 barrels a day from February 1, 2007. On the demand side, global oil demand growth remains moderate and is expected to rise by 1.5 million barrels per day in 2007 to 86 million barrels a day. This growth comes mainly from China and India. We expect this demand increase and the commitment from OPEC to lower production to stabilize crude oil prices in the near term.

Since the beginning of 2007, WTI has dropped to a low of US\$49.90/bbl, but has since rebounded to approximately US\$59/bbl in early February.

### Crude Oil Differentials

In Canada, heavy crude oil differentials averaged US\$21.79/bbl (33% of WTI) for the year, compared to \$20.82/bbl (37% of WTI) in 2005. Differentials narrowed in the summer, as demand increased for heavy blends relative to light blends. This reflected normal seasonal narrowing as we headed into the summer asphalt season. Typically, heavy crude oil differentials widen going into the fourth quarter but this year, they maintained their summer levels following the late-year falloff in WTI. In addition, heavy crude oil differentials are tighter than usual this winter since OPEC cuts tend to be heavy barrels. This increases the value of heavy barrels relative to lighter barrels.

The US Gulf Coast Mars differential widened, averaging US\$7.34/bbl in 2006 as compared to US\$6.59/bbl in 2005. This was primarily due to higher WTI prices, temporary declines in demand due to refinery maintenance schedules and increased competition from Canadian heavy crude down the Spearhead pipeline into Cushing, Oklahoma and the Pegasus pipeline into Nederland, Texas. Late in the year, Mars differentials narrowed in response to falling WTI prices and OPEC production quota cuts.

The Yemen Masila differential narrowed substantially relative to WTI during 2006, averaging US\$3.00/bbl compared to US\$5.71/bbl last year. This largely reflects the impact of stronger Brent pricing since Masila crude is priced off Brent, coupled with continued strong Asian demand.

**The Brent/WTI differential strengthened during 2006, creating strong crude oil pricing for our North Sea barrels.**

The Brent/WTI differential strengthened during 2006 averaging US\$1.08/bbl as compared to US\$2.20/bbl in 2005, resulting in a solid crude oil price for our North Sea barrels. The spread between WTI and Brent broke away from historical norms where WTI usually trades at a premium of US\$1.50/bbl to US\$2.00/bbl. Several times during the year, WTI traded at a discount to Brent. This was caused by weak US demand during a heavier than usual maintenance season, coupled with high US crude inventory levels as production from the US Gulf Coast came back on stream following damage caused by Hurricanes Katrina and Rita in 2005. On-going production outages in Nigeria also helped to push Brent up relative to the North American WTI benchmark. Near the end of the year, Brent gained more upside support due to the production quota cut from OPEC. OPEC cuts have a more immediate impact on Brent relative to WTI given the shorter transit time of Brent to world markets.

**Natural Gas Reference Prices**

Natural gas prices averaged US\$6.99/mmbtu, 22% below 2005 levels. NYMEX reached record price and volatility levels in late 2005, driven mainly by the impact of hurricanes Katrina and Rita and speculation around the 2005/2006 North American winter season. In 2006, the mildest January temperatures on record were experienced in several key North American natural gas consuming regions which resulted in a

weakening of NYMEX. This created a significant gas storage overhang. Prices remained soft throughout the year reflecting high storage levels, an uneventful hurricane season and a mild 2006/2007 winter prediction due to the warming effect of El Nino. Lack of sustained cold temperatures heading into 2007 will discourage storage withdrawals, which puts further downward pressure on prices.

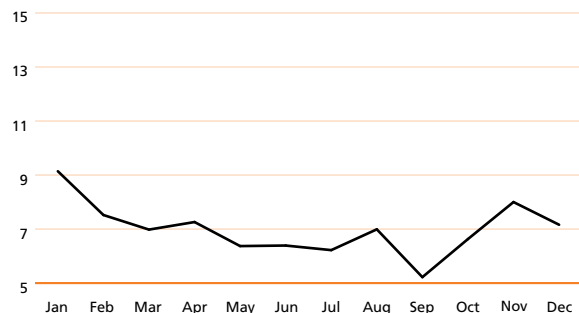
**2005 vs 2004—Higher realized prices added \$813 million to net income**

Crude oil prices remained strong in 2005 reaching new highs and new levels of volatility. While global demand was moderate and supply levels adequate, the stability and security of long-term supply remained a concern, along with tightening refining capacity worldwide.

Natural gas prices reached record highs and experienced increased volatility. Prices early in the year were propped up by strong oil prices. The disruptions caused by the hurricanes pushed North American gas prices to new highs. The volatility did not end with the hurricane activity, but continued into the winter, as markets speculated on the impact of a cold or mild winter on tight supply. Prices peaked on December 13, 2005 with NYMEX gas settling at US\$15.38/mmbtu.

The full benefit of higher benchmark prices wasn't reflected in our realized prices because of the weaker US dollar in 2005. All of our oil sales and most of our gas sales are denominated in, or referenced to, US dollars. As a result, the weaker US dollar decreased net sales for the year by approximately \$270 million, and reduced our realized crude oil and natural gas prices by approximately \$4.40/bbl and \$0.65/mcf, respectively, compared to 2004.

**2006 NYMEX Monthly Average Natural Gas Prices (US\$/mmbtu)**



## Operating Expenses

(Cdn\$/boe)	2006		2005		2004	
	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>						
Yemen	4.45	8.11	3.63	6.75	2.80	5.64
Canada	10.31	12.73	8.21	10.34	7.12	8.98
United States	8.17	9.45	6.35	7.33	5.30	6.12
United Kingdom	11.28	11.28	14.90	14.90	8.26	8.26
Australia	–	–	–	–	32.94	35.73
Other Countries	2.87	3.13	5.55	6.08	3.76	4.09
Average Conventional	6.95	9.69	6.03	8.70	5.13	7.59
<b>Synthetic Crude Oil</b>						
Syncrude	27.53	30.43	26.95	27.22	19.89	20.61
<b>Average Oil and Gas</b>	<b>8.77</b>	<b>11.96</b>	<b>7.36</b>	<b>10.34</b>	<b>6.15</b>	<b>8.83</b>

Note:

<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.

### 2006 vs 2005—Higher operating expenses decreased net income by \$22 million

In Yemen, operating costs on a per-unit basis are increasing as fixed costs from our central processing facilities, combined with increased water handling costs, are spread over lower production volumes. At Masila, lower production and increased service rig activity required to minimize production declines, combined with the costs associated with the replacement of a single point mooring system used to load oil onto tankers, increased our corporate average by \$0.20/boe. Block 51 operating costs increased our corporate average by \$0.22/boe, reflecting higher manpower costs, increased water handling costs at the new facilities, maintenance costs associated with equipment repairs and power outages, and increased fuel consumption and fuel prices. We expect Yemen operating costs per barrel to continue to increase as our production declines.

Following the sale of Canadian conventional oil and gas properties in 2005, we have proportionately higher production from our heavy oil properties, which have higher operating costs compared to the lighter oil production we sold. Canadian operating costs increased our corporate average by \$0.18/boe. We are focused on increasing recovery rates from our heavy oil properties by developing new technologies.

Operating costs in the Gulf of Mexico increased from last year due to industry cost pressures caused by the strong commodity price environment and the 2005 hurricane season.

Lower production volumes and workovers on our shelf properties at the start of the year increased our corporate average by \$0.39/boe.

With the sale of Canadian production in 2005, barrels from the North Sea are contributing a higher percentage of our total production. As the North Sea has higher operating costs than our average cost per barrel, the change in production mix has increased our corporate average by \$0.32/boe. This was offset by lower operating costs relative to 2005, as operating expenses last year included repair costs related to turbine failures. This reduced our corporate average by \$0.26/boe. We expect our North Sea operating costs to decrease on a per-unit basis in 2007, with increased low-operating cost production expected from Buzzard.

---

**We expect 2007 operating costs to decrease on a per-unit basis with increased low-operating cost production from Buzzard.**

---

Syncrude increased our corporate average operating costs by \$0.72/boe as a result of maintenance activities and the turnaround of a coker during the first quarter of 2006, combined with costs related to start-up of the Stage 3 expansion.

The stronger Canadian dollar decreased our US-dollar denominated operating costs, reducing our corporate average by \$0.38/boe, compared to 2005.

### 2005 vs 2004—Higher operating expenses decreased net income by \$91 million

In 2005, higher operating costs reflect the change in our profile as more of our production came from higher-cost areas such as the North Sea and from Canadian heavy oil following the Canadian property sales completed that year. Operating costs were negatively impacted by storm-related costs and maintenance activities. In addition, high levels of industry activity and higher energy costs, driven by record commodity prices, increased our operating costs.

Our operations at Masila in Yemen reflect the maturing asset base and have higher operating costs, mainly from increased service rig activity to minimize production declines. These higher costs added \$0.09/boe to our corporate average. Block 51 operating costs were higher than Masila, reflecting the use of temporary production facilities. Higher operating costs from Block 51 increased our corporate average by \$0.53/boe.

Industry cost pressures and the sale of conventional production increased our Canadian unit operating costs in 2005. Although we sold high-cost production relative to our corporate average, we expect our overall Canadian operating costs to increase as we have proportionately higher production from our heavy oil properties. These properties have higher operating costs compared to the lighter oil production that was sold.

In the Gulf of Mexico, lower volumes of higher-cost barrels

at Aspen, along with \$12 million of Aspen-1 intervention costs expensed in 2004, decreased our corporate average by \$0.10/boe. Workovers on our shelf properties, coupled with lower production and property damage costs not covered by insurance, increased our corporate average by \$0.05/boe from 2004.

Higher-cost North Sea production increased our corporate average unit costs by \$1.14/boe. Our North Sea operating costs were higher than anticipated as a result of maintenance and repair work caused by generator failures in the second quarter and major maintenance turnaround and facilities upgrading at the Scott platform in the third quarter.

Our Australian operations ceased in late 2004 and the exclusion of these high-cost, late-life barrels reduced our corporate average by \$0.57/boe. US-dollar denominated operating costs were lower when translated to Canadian dollars as a result of the weak US dollar. Our corporate average was reduced by \$0.30/boe as a result.

Syncrude operating costs per boe were 35% higher than in 2004. Turnaround and maintenance costs accounted for half of the increase, as we completed major turnarounds on various upgrading units during the year. In addition, high levels of industry activity in the oil sands have put upward pressure on costs. When combined with higher energy costs required in the upgrading process, our corporate average increased by \$0.34/boe.

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

	2006		2005		2004	
	Before Royalties <sup>1</sup>	After Royalties	Before Royalties <sup>1</sup>	After Royalties	Before Royalties <sup>1</sup>	After Royalties
(Cdn\$/boe)						
<b>Conventional Oil and Gas</b>						
Yemen	9.67	17.61	8.56	15.93	4.35	8.77
Canada	11.22	13.84	9.26	11.67	9.02	11.37
United States <sup>2</sup>	16.28	18.84	15.39	17.77	12.93	14.93
United Kingdom	30.22	30.22	33.25	33.25	22.44	22.44
Australia	—	—	—	—	5.82	6.31
Other Countries	4.30	4.69	6.20	6.79	9.90	10.77
Average Conventional	13.12	18.30	11.78	17.00	7.87	11.64
<b>Synthetic Crude Oil</b>						
Syncrude	4.81	5.32	3.08	3.12	2.75	2.85
<b>Average Oil and Gas</b>	<b>12.38</b>	<b>16.88</b>	<b>11.23</b>	<b>15.77</b>	<b>7.52</b>	<b>10.80</b>

Notes:

<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 charge described in Note 6 of our Consolidated Financial Statements.

### 2006 vs 2005—Higher oil and gas DD&A decreased net income by \$48 million

Our 2006 DD&A expense includes \$93 million (\$1.21/boe) of impairment expense primarily related to two natural gas producing properties in the Gulf of Mexico. The impairment was caused by disappointing development programs and negative year-end reserve revisions. The carrying values of the impaired properties have been reduced to their estimated fair value. In addition, our 2006 DD&A expense includes \$15 million (2005 —\$58 million) relating to the write down of a portion of our purchase price allocation to unproved properties purchased in the North Sea as a result of unsuccessful exploration activities. Our 2006 average depletion rate excluding impairment charges is \$12.38/boe, 10% above our 2005 average.

In Yemen, we began depleting the permanent production facilities on Block 51 during the year. Strong crude oil prices allowed us to continue to maximize the recovery of the costs we paid on behalf of the government. This increased our corporate average by \$0.64/boe.

---

#### The strong Canadian dollar reduced our corporate DD&A rate by \$0.72/boe from 2005.

---

The increased Canadian depletion rate reflects the depletion of costs associated with our coalbed methane projects in central Alberta. Our corporate average is higher by \$0.35/boe as a result. We expect our depletion rate for our coalbed methane projects to decline as the wells de-water and we are able to recognize additional reserves. Depletion rates for our deep-water assets in the Gulf of Mexico increased our average by \$0.28/boe primarily as a result of reserve revisions late in 2005.

Our depletion rate for our North Sea assets is higher than our average, primarily from the allocation of the purchase price we paid for these assets in 2004. Our corporate average is increasing as the North Sea becomes a larger proportion of our total production and from lower production in Canada

following the sale of conventional oil and gas assets in 2005. This change increased our corporate average by \$0.42/boe. We expect our corporate average will continue to increase in 2007 as we begin to deplete Buzzard.

The Stage 3 expansion at Syncrude began producing during the year and we started depleting these assets in 2006. This increased our corporate average by \$0.23/boe.

The strong Canadian dollar reduced our DD&A expense relative to 2005 as the depletion of our international and US assets is denominated in US dollars. This lowered our corporate average by \$0.72/boe from last year.

### 2005 vs 2004—Higher oil and gas DD&A decreased net income by \$308 million

Strong production volumes, new production from our North Sea assets and additional capital cost recovery from Block 51 in Yemen increased our oil and gas DD&A compared with 2004 levels. We also expensed \$58 million related to unproved North Sea properties as a result of unsuccessful exploration activities.

Block 51 production in Yemen increased our corporate unit depletion by \$2.21/boe from 2004 as a result of carried interest accounting for the recovery of Block 51 capital costs. Strong production and higher realized oil prices have resulted in faster recovery of capital costs we paid on behalf of the government.

Our Canadian depletion rate per unit has increased slightly compared with 2004. Reserve revisions at the end of 2004 increased our 2005 heavy oil depletion rate. This increase was somewhat offset when we stopped depleting our Canadian assets held for sale in the second quarter, but continued to recognize related production. The disposition of these assets in the third quarter changed our asset mix and reduced our average annual corporate depletion rate by \$0.23/boe.

Depletion rates in the Gulf of Mexico increased following reserve revisions in late 2004. Reduced volumes offset the increase in rates with minimal impact on our overall unit rate.

North Sea depletion increased our corporate average by \$2.37/boe in 2005. The depletable carrying costs of our Scott, Telford and Farragon fields include an allocation of the purchase price we paid for these assets. In addition, our North Sea depletion includes \$58 million relating to a partial write-

off of our purchase price allocation to unproved properties subject to unsuccessful exploration activities.

The strengthening Canadian dollar offset these increases as the depletion of our international and US assets is denominated in US dollars. This lowered our corporate average by \$0.70/boe compared with 2004.

**Exploration Expense <sup>1</sup>**

(Cdn\$ millions)	2006	2005	2004
Seismic	128	53	73
Unsuccessful Drilling	169	143	125
Other	65	55	48
<b>Total Exploration Expense</b>	<b>362</b>	<b>251</b>	<b>246</b>
New Growth Exploration	491	456	266
Geological and Geophysical Costs	128	53	73
<b>Total Exploration Expenditures</b>	<b>619</b>	<b>509</b>	<b>339</b>
Exploration Expense as a % of Exploration Expenditures	58%	49%	73%

Note:

<sup>1</sup> 2005 and 2004 includes exploration expense from discontinued operations. See Note 14 to our Consolidated Financial Statements.

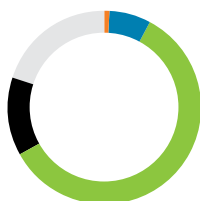
**2006 vs 2005—Higher exploration expense reduced net income by \$111 million**

Our 2006 exploration activities were focused on drilling 20 wells, mostly in the Gulf of Mexico and the North Sea, and acquiring seismic data. We were successful at Great White West and Ringo in the Gulf of Mexico. In early 2007, we completed drilling operations at our Golden Eagle prospect on License P928 in the UK North Sea. The discovery well was drilled to a depth of approximately 7,500 feet and encountered hydrocarbons. A successful sidetrack well was drilled to appraise the accumulation and we are currently evaluating development options.

Our unsuccessful drilling results were primarily in the Gulf of Mexico, where we expensed \$135 million in dry hole costs. Early in the year, we expensed \$49 million for the Pathfinder well, which found non-commercial quantities of hydrocarbons, after reaching a total depth of 31,196 feet. Unsuccessful wells on the shelf in the Gulf of Mexico include West Cameron 135 and 109 (\$23 million and \$14 million respectively) and Vermilion 65 (\$15 million). During the year, we also expensed \$29 million of capitalized costs related to Big Bend as it was determined that development was uneconomic and the block was relinquished. In the North Sea, dry hole costs included unsuccessful exploratory wells at Zanzibar (\$10 million) and Black Cat (\$7 million). Exploration expense also includes costs relating to Ukot South, offshore Nigeria, which encountered wet sands and was plugged and abandoned, and costs relating to three unsuccessful wells on Block 51 in Yemen.

**2006 Exploration Expense**

- Yemen (1%)
- Canada (7%)
- USA (59%)
- UK (13%)
- Other (20%)  
(including 4% Nigeria)



Our geological and geophysical costs include \$128 million of seismic data acquired during the year of which half relates to the Gulf of Mexico. The balance was spent on data relating to Canada, Norway, the North Sea, Nigeria and other international targets.

We continue to focus on large unconventional resource opportunities in Canada. In 2006, we acquired approximately 100 sections of prospective shale gas acreage in northeast British Columbia for \$50 million, which we intend to evaluate in 2007.

---

**We continue to grow our unconventional resource in Canada. In 2006, we acquired a sizeable shale gas land position in northeast BC.**

---

In 2007, we plan to invest approximately \$700 million to drill up to 19 exploration wells and acquire seismic data and access to new exploratory acreage. In the Gulf of Mexico we have four deep-water and five shelf-gas prospects planned, while we anticipate drilling five exploration wells in the North Sea. We expect to drill three exploration wells on Block 51 in Yemen, one deep-water exploration well offshore West Africa and one exploration well in Colombia.

**2005 vs 2004—Higher exploration expense reduced net income by \$5 million**

Our 2005 exploration program was active, as we spent more than \$500 million on 20 high-potential exploration wells in our key basins. In the Gulf of Mexico, Knotty Head,

drilled to a depth of 34,189 feet, encountered hydrocarbons in multiple zones.

Our 2005 exploration expense includes costs associated with unsuccessful wells in the Gulf of Mexico, North Sea, offshore West Africa and Yemen. In the Gulf of Mexico, we expensed \$44 million for the Vrede well. Vrede, a sub-salt prospect drilled to a total depth of 32,600 feet, encountered non-commercial quantities of hydrocarbons and was temporarily abandoned. We also wrote off costs relating to our Castleton dry hole, together with trailing costs related to the 2004 Crested Butte, Wind River and Fawkes wells. These wells, with the exception of Wind River, were located in the deep water.

In the North Sea, exploration expense includes costs relating to Black Horse, Polecat, Bennachie and Saracen. The Black Horse and Polecat wells encountered hydrocarbons, but insufficient to warrant stand-alone development. We will continue to evaluate these reservoirs in combination with other potential development projects that may be sanctioned in the future. Bennachie was abandoned after encountering no reservoir sands in the target zone. Saracen was written off earlier in 2005 as an unsuccessful exploratory well.

Internationally, we expensed costs related to four unsuccessful wells on Block 51 in Yemen and we abandoned our deep-water Eferé well in Nigeria, as well as our K-2 well on Block K in Equatorial Guinea.

**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.

**Before Royalties**

	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>

	2005						
(\$/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	62.07	42.42	60.26	57.83	59.96	71.00	57.97
Royalties and Other	(28.71)	(8.75)	(8.06)	–	(5.23)	(0.71)	(16.70)
Operating Expenses	(3.63)	(8.21)	(6.35)	(14.90)	(5.55)	(26.95)	(7.36)
In-country Taxes <sup>1</sup>	(7.17)	–	–	–	–	–	(3.34)
<b>Cash Netback</b>	<b>22.56</b>	<b>25.46</b>	<b>45.85</b>	<b>42.93</b>	<b>49.18</b>	<b>43.34</b>	<b>30.57</b>

	2004							
(\$/boe)	Australia	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	51.22	47.59	35.76	46.94	47.45	43.07	52.80	44.94
Royalties and Other	(4.00)	(23.98)	(7.40)	(6.29)	–	(3.49)	(1.84)	(13.65)
Operating Expenses	(32.94)	(2.80)	(7.12)	(5.30)	(8.26)	(3.76)	(19.89)	(6.15)
In-country Taxes <sup>1</sup>	–	(5.82)	–	–	–	–	–	(2.48)
<b>Cash Netback</b>	<b>14.28</b>	<b>14.99</b>	<b>21.24</b>	<b>35.35</b>	<b>39.19</b>	<b>35.82</b>	<b>31.07</b>	<b>22.66</b>

**After Royalties**

	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>

	2005						
(\$/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	62.07	42.42	60.26	57.83	59.96	71.00	57.97
Operating Expenses	(6.75)	(10.34)	(7.33)	(14.90)	(6.08)	(27.22)	(10.34)
In-country Taxes <sup>1</sup>	(13.35)	–	–	–	–	–	(4.69)
<b>Cash Netback</b>	<b>41.97</b>	<b>32.08</b>	<b>52.93</b>	<b>42.93</b>	<b>53.88</b>	<b>43.78</b>	<b>42.94</b>

	2004							
(\$/boe)	Australia	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	51.22	47.59	35.76	46.94	47.45	43.07	52.80	44.94
Operating Expenses	(35.73)	(5.64)	(8.98)	(6.12)	(8.26)	(4.09)	(20.61)	(8.83)
In-country Taxes <sup>1</sup>	–	(11.72)	–	–	–	–	–	(3.57)
<b>Cash Netback</b>	<b>15.49</b>	<b>30.23</b>	<b>26.78</b>	<b>40.82</b>	<b>39.19</b>	<b>38.98</b>	<b>32.19</b>	<b>32.54</b>

Note:

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

**ENERGY MARKETING**

(Cdn\$ millions)	2006	2005	2004
Physical Sales <sup>1</sup>	40,920	37,873	28,554
Physical Purchases <sup>1</sup>	(39,925)	(36,988)	(28,074)
Net Financial Transactions <sup>1</sup>	314	(38)	128
<b>Net Revenue</b>	<b>1,309</b>	<b>847</b>	<b>608</b>
Transportation Expense	(789)	(641)	(451)
Other	20	(2)	(2)
<b>Net Marketing Revenue</b>	<b>540</b>	<b>204</b>	<b>155</b>
<b>Contribution to Net Marketing Revenue by Product Type:</b>			
North American Natural Gas	390	117	93
International Crude Oil	114	70	52
North American Power	16	8	4
Other	20	9	6
<b>Net Marketing Revenue</b>	<b>540</b>	<b>204</b>	<b>155</b>
Depreciation, Depletion, Amortization and Impairment	(12)	(11)	(10)
General and Administrative	(112)	(89)	(58)
<b>Marketing Contribution to Income from Continuing Operations before Income Taxes</b>			
	<b>416</b>	<b>104</b>	<b>87</b>
<b>Natural Gas</b>			
Physical Sales Volumes <sup>2</sup> (bcf/d)	5.4	4.9	4.9
Transportation Capacity (bcf/d)	3.3	4.0	3.5
Storage Capacity (bcf)	50	30	27
<b>Crude Oil</b>			
Physical Sales Volumes <sup>2</sup> (mbbls/d)	705	510	465
Storage Capacity (mbbls)	1,749	580	408
<b>Power</b>			
Physical Sales Volumes – Power <sup>2</sup> (MWW/d)	4,388	2,548	1,191
Generation Capacity (MWW/hr)	87	53	53
<b>Value-at-Risk</b>			
Year End	26	24	21
High	33	28	42
Low	17	11	17
Average	23	21	29

Notes:

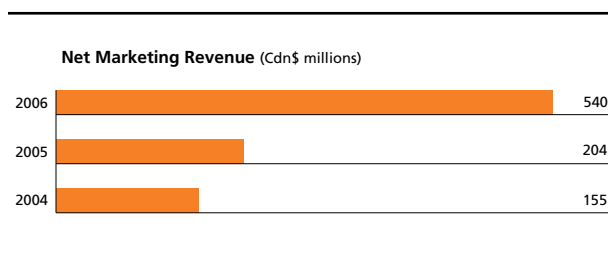
<sup>1</sup> Marketing's physical sales, physical purchases and net financial transactions are reported net on the Consolidated Statement of Income as marketing and other.

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

**2006 vs 2005—Net marketing revenue increased net income by \$336 million**

Marketing had record results in 2006, with all groups achieving new highs or starting new businesses. The largest contribution continues to come from our North American natural gas marketing group where we capitalized on our asset-based trading strategy. Time and location spread trading generated most of our gas gains but we were also successful in generating revenues through the optimization of our

transportation and storage capacity. Volatility within the North American gas markets created market inefficiencies for us to capitalize on. North American gas prices started 2006 at US\$10.63/mcf and closed the year at US\$6.30/mcf. Storage overhang and speculation around weather and possible hurricanes caused significant changes in prices during the year. We also took advantage of opportunities late in the year to add to our storage capacity.



Our crude oil marketing group also generated record results by successfully taking advantage of crude quality, location and time spreads. The group generated physical and financial trading gains by taking advantage of the contango (rising forward month prices) in the crude oil forward curve. In addition, we captured profits around quality spreads by diverting crude oil, or by blending to enhance the crude quality, and attract higher prices. While our strategies remained largely the same in 2006, we executed more transactions and added more capacity, particularly storage, during the year. With our newly established marine transportation capabilities, this group is well positioned to start marketing our Buzzard production in 2007.

Our power marketing group is the largest supplier of power to the commercial and industrial sector in Alberta and net revenue contributions exceeded expectations.

**Our power marketing group is the largest supplier of power to the commercial and industrial sector in Alberta.**

We continued our expansion into new markets during the year with acquisitions in the North American NGL trading business and a UK acquisition which positioned us in the UK and European gas and power markets.

Results from our marketing group vary between periods and historical results are not necessarily indicative of future

**Composition of Net Marketing Revenue**

(Cdn\$ millions)	2006	2005
Trading Activities	520	195
Non-Trading Activities	20	9
<b>Total Net Marketing Revenue</b>	<b>540</b>	<b>204</b>

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.

**2005 vs 2004—Net marketing revenue increased net income by \$49 million**

Marketing delivered strong results in 2005, with net revenue of \$204 million. Our gas marketing group grew their net revenue to \$117 million. We achieved these results through our continued focus on an asset-based trading strategy, using our transportation and storage capacity to take advantage of seasonal and locational pricing differences and market inefficiencies.

While 2005 was a profitable year, it was also volatile with hurricane activity in the Gulf of Mexico disrupting gas supply and infrastructure. This volatility caused us to recognize losses in the third quarter on financial contracts hedging our physical assets. However, we were able to recognize gains on our physical assets in the fourth quarter as we used our transportation capacity and sold gas from storage. This allowed us to recoup our third quarter losses and recognize \$175 million of net revenue in the fourth quarter. We also generated profits from financial contracts that captured time and location spreads.

Our crude oil marketing group contributed \$70 million of net revenue in 2005, an increase of 35% over 2004. Similar to prior years, we continued to capitalize on forward prices, as well as differences in crude qualities. In particular, in 2005, we took advantage of contango by successfully pricing our purchases lower than our sales, and by financially trading calendar spreads. We also captured profits around quality spreads by diverting crude oil, or by blending to enhance the crude quality, and attract higher prices.

### Trading Activities

In marketing, 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 not designated as hedges for accounting purposes using mark-to-market 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.

We value derivative trading contracts daily using:

- actively quoted markets such as the New York Mercantile Exchange and the International Petroleum Exchange; and
- other external sources such as the Natural Gas Exchange, independent price publications and over-the-counter broker quotes.

### Fair Value of Derivative Contracts

At December 31, 2006, the fair value of our derivative contracts not designated as hedges totalled \$360 million (2005—\$169 million). Below is a breakdown of this fair value by valuation method and contract maturity.

(Cdn\$ millions)	Maturity				Total
	< 1 year	1-3 years	4-5 years	> 5 years	
<b>Prices</b>					
Actively Quoted Markets	190	(26)	(21)	–	143
From Other External Sources	216	(6)	13	(6)	217
Based on Models and Other Valuation Methods	–	–	–	–	–
<b>Total</b>	<b>406</b>	<b>(32)</b>	<b>(8)</b>	<b>(6)</b>	<b>360</b>

### Changes in Fair Value of Derivative Contracts

(Cdn\$ millions)	Total
Fair Value at December 31, 2005	169
Change in Fair Value of Contracts	576
Net Losses (Gains) on Contracts Closed	(385)
Changes in Valuation Techniques and Assumptions <sup>1</sup>	–
<b>Fair Value at December 31, 2006</b>	<b>360</b>
Unrecognized Gains on Hedges of Future Sale of Gas Inventory at December 31, 2006	25
<b>Total Outstanding at December 31, 2006</b>	<b>385</b>

Note:

<sup>1</sup> Our valuation methodology has been applied consistently year-over-year.

As a physical energy marketer, we match the contract months of our derivative contracts with the contract months of our physical sales and purchases. As a result, the fair value of our derivative contracts as at December 31, 2006 includes amounts with no ongoing commodity price or foreign currency exchange risk. Excluding these amounts, the fair value of our derivative contracts at December 31, 2006 was \$102 million.

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. While forward prices vary, the value of the contracts only varies to the extent they are economically exposed or unprotected. As most of our unrealized value is not economically exposed, we expect to realize the majority of this fair value.

More than 113% of the unrealized fair value relates to contracts that settle within 12 months. Contract maturities vary from a single day up to 12 years. Those maturing beyond one year primarily relate to North American natural gas positions. The relatively short maturity of our contracts, the high quality of our valuations from quoted markets and external sources and the limited economic exposure combine to lower our portfolio risk.

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 capacity contracts have market value, similar to financial commodity contracts, as future margins realized depend on future prices and, more importantly, pricing differences. The market value of these capacity contracts varies depending on the change in future prices and pricing relationships. We routinely hedge the economic value of our capacity contracts using various types of derivative contracts, thereby limiting volatility in our economic results. Accounting rules, however, increase volatility in our reported results since they require us to recognize the change in fair value of derivative contracts hedging our capacity contracts, but do not allow us to recognize the change in fair value of the capacity contracts themselves until the contracts are used. As a result, when prices or pricing relationships change, we may be required to include gains or losses in our reported results in different periods even though

our underlying economic results may be largely unchanged. At the end of 2006, unrecognized future commitments related to our transportation and storage capacity contracts was a loss of \$81 million. This amount has been included in our contractual obligations, commitments and guarantees in the MD&A.

We have designated certain derivative contracts as accounting cash flow hedges of the future sale of our gas in storage. Mark-to-market gains and losses on these designated contracts are excluded from income until the underlying inventory is sold. At December 31, 2006, we had \$25 million of unrecognized gains on these derivative contracts. These contracts have been valued from actively quoted markets and will settle within 12 months. In late 2006, we de-designated certain futures contracts that had been designated as cash flow hedges of future sales of our natural gas in storage. Gains of \$65 million on the futures contracts have been deferred and are expected to be recognized in net income in the first quarter of 2007.

#### Non-Trading Activities

We enter into fee-for-service contracts related to transportation and storage of third-party oil and gas. We also earn income from our power generation facilities at Balzac and Soderglen. We earned \$20 million from our non-trading activities in 2006 (2005—\$9 million).

### CHEMICALS

(Cdn\$ millions)	2006	2005	2004
<b>Net Sales</b>	407	398	378
<b>Sales Volumes</b> (thousand short tons)			
Sodium Chlorate	487	493	506
Chlor-alkali	451	450	403
<b>Operating Profit</b> <sup>1</sup>	124	136	105
<b>Operating Margin</b> <sup>2</sup>	30%	34%	28%
<b>Chemicals Contribution to Income from Continuing Operations Before Income Taxes</b>	44	37	40
<b>Capacity Utilization</b>	95%	96%	95%

Notes:

<sup>1</sup> Total revenues less operating costs, transportation and other.

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

### 2006 vs 2005— Lower chemicals operating profit decreased net income by \$12 million

Our investment in our chemicals business is held through our 61.4% interest in the Canexus Limited Partnership. While North American prices for sodium chlorate remained strong throughout 2006, sales volumes fell slightly from last year as a result of pulp mill closures. Chlor-alkali volumes and prices in North America remained steady. US-dollar denominated North American sales were reduced \$12 million from the stronger Canadian dollar during 2006. Sales and operations from the Brazil plant remained solid as a result of strong demand from Aracruz Cellulose, our primary customer, and from the merchant market.

---

**During the year, Canexus began an expansion of the Brandon, Manitoba plant, which benefits from low electricity rates.**

---

Late in the year, Canexus commenced an expansion of the Brandon, Manitoba plant to increase capacity by 12% by early 2008. The Brandon plant benefits from low electricity rates in the province of Manitoba, where the electricity market is based on hydroelectric power and is regulated.

### 2005 vs 2004—Higher chemicals operating profit increased net income by \$31 million

In the third quarter of 2005, we monetized a portion of our chemicals business by creating the Canexus Income Fund through an initial public offering (IPO), which raised net

proceeds of \$301 million. Canexus Limited Partnership, also raised US\$167 million (\$200 million) of bank debt. Canexus Limited Partnership used the proceeds from Canexus Income Fund's IPO and the bank debt, together with the issuance of 50.5 million exchangeable units of the Canexus Limited Partnership to Nexen, to purchase our chemicals operations. We have retained a 61.4% interest in the chemicals operations through our investment in Canexus Limited Partnership, and we recorded a gain of \$193 million on the dilution of our interest.

Despite lower sales volumes, strong chlor-alkali prices and higher margins generated strong results for the chemicals business. Sodium chlorate volumes decreased compared with 2004 as a result of our decision in early 2005 to forego low-margin business consistent with our restructuring effort and the closure of our Amherstburg, Ontario plant. Sales and operations from the Brazil plant remained strong as a result of continued strong demand from Aracruz Cellulose, our primary customer in Brazil, and an expanded presence in the merchant market.

The weaker US dollar put pressure on our US-dollar denominated sales, reducing net sales by \$13 million. During 2005, we purchased US-dollar foreign currency call options to mitigate our exposure to the weakening dollar. We generated \$4 million of income as a result of these call options.

Our chemicals contribution was reduced by \$12 million for an impairment charge relating to our chemicals plant in Amherstburg, which was closed in the third quarter of 2005.

## CORPORATE EXPENSES

### General and Administrative (G&A)

(Cdn\$ millions)	2006	2005	2004
General and Administrative Expense before Stock-Based Compensation	345	302	206
Stock-Based Compensation <sup>1</sup>	210	507	93
<b>Total General and Administrative Expense</b>	<b>555</b>	<b>809</b>	<b>299</b>

Note:

<sup>1</sup> Includes tandem option plan, stock options for our US-based employees and stock appreciation rights plan.

### 2006 vs 2005—Lower costs increased net income by \$254 million

Our G&A expense before stock-based compensation increased 14% primarily from additional costs to expand our marketing operations into new markets. Acquisitions during the year enabled us to increase our NGL business in North America and to expand our European trading operations. Our G&A expense also includes higher variable compensation stemming from our marketing group's strong performance in 2006.

### Total G&A expense decreased 31% in 2006 from lower stock-based compensation costs.

Changes in our share price creates 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. In 2006, our share price increased 16% from \$55.42 to \$64.20, creating over \$2.3 billion of shareholder value. The expense represents approximately 9% of the increase in shareholder

value. Cash payments to employees for our stock-based compensation programs were \$119 million in 2006, a 61% increase over 2005.

### 2005 vs 2004—Higher costs reduced net income by \$510 million

Our stock-based compensation expense in 2005 reflects the significant increase in the price of our common shares. Our share price increased 128% from \$24.35 to \$55.42, adding more than \$8 billion of shareholder value. Notwithstanding this increase in our share price, cash payments to employees under our stock-based compensation programs only amounted to \$74 million.

Our growing international presence and the expansion of our businesses increased our G&A costs during the year. Costs reflect more employees, additional travel, and higher compliance and governance costs, combined with increased variable incentive compensation stemming from our record results. We also incurred additional costs related to our disposition activities and the integration of our North Sea operations acquired in late 2004.

## Interest

(Cdn\$ millions)	2006	2005	2004
Interest	294	275	194
Less: Capitalized	(241)	(178)	(51)
<b>Net Interest Expense</b>	<b>53</b>	<b>97</b>	<b>143</b>
Effective Rate	6.3%	6.4%	6.6%

### 2006 vs 2005—Lower net interest expense increased net income by \$44 million

Our financing costs have increased \$19 million from 2005. Additional borrowings to finance our 2006 capital program increased financing costs by approximately \$28 million. This was partially offset however, by the stronger Canadian dollar which decreased our US-dollar denominated interest by \$16 million. The Canexus debt, consolidated with our results, increased our interest expense by \$7 million.

The amount of interest we capitalized on our major development projects grew by \$63 million, primarily from increased investment in the North Sea Buzzard project, at Long Lake and the Stage 3 expansion at Syncrude prior to its start-up. We expect interest capitalized on projects to decrease in 2007 as we ceased capitalizing interest on the Syncrude expansion in August 2006 and on Buzzard in January 2007. We expect to

continue to capitalize interest on our Long Lake project prior to its completion in 2007. Our net interest expense is expected to increase once these projects are completed.

### 2005 vs 2004—Lower net interest expense increased net income by \$46 million

We acquired our North Sea assets in late 2004. We partially financed this acquisition with US\$1 billion of new long-term debt, increasing our interest costs by \$87 million in 2005. Interest expense also increased \$3 million relating to the Canexus debt consolidated with our results. However, the stronger Canadian dollar lowered our US-dollar denominated interest by \$12 million. During the last two years, we have taken advantage of declining interest rates by replacing our higher-cost preferred securities with new long-term debt at lower rates.

**Income Taxes**

(Cdn\$ millions)	2006	2005	2004
Current	368	339	248
Future	315	(234)	119
<b>Total Provision for Income Taxes</b>	<b>683</b>	<b>105</b>	<b>367</b>
Disclosed as:			
Provision for Income Taxes—Continuing Operations	683	234	317
Provision for Income Taxes—Discontinued Operations <sup>1</sup>	–	(129)	50
<b>Total Provision for Income Taxes</b>	<b>683</b>	<b>105</b>	<b>367</b>
Effective Rate	53%	8%	32%

Note:

<sup>1</sup> See Note 14 to our Consolidated Financial Statements.

### 2006 vs 2005—Effective tax rate increases from 8% to 53%

In early 2006, the UK government substantively enacted increases to the supplementary tax rate on our North Sea oil and gas activities from 10% to 20%, effective January 1, 2006. This increased our future income tax liabilities, resulting in a charge of \$277 million during the first quarter. During the second quarter, federal and certain provincial governments in Canada reduced corporate income tax rates. These rate reductions lowered our future income tax liabilities by \$32 million. Our effective tax rate excluding the effect of these tax rate changes was 33%.

---

**In 2006, an increase in the UK supplemental tax rate on oil & gas activities resulted in a future income tax expense of \$277 million.**

---

Current income taxes include cash taxes in Yemen of \$286 million (2005—\$296 million; 2004—\$227 million). Our current income tax provision also includes federal and state taxes in the US, cash taxes in Colombia and capital taxes in Canada.

### 2005 vs 2004—Effective tax rate decreases from 32% to 8%

The recovery of future taxes payable of \$234 million is attributable to the disposition of our oil and gas producing properties in Canada and the sale of our chemicals business to the Canexus Limited Partnership. As a result of the dispositions, we revalued our future income tax liabilities for the change in the underlying book and tax values. This revaluation resulted in the reduction of our future income tax liabilities. In addition, the disposition gains were taxed at lower capital gains tax rates. Removing the tax impact of the dispositions, the effective tax rate for our continuing operations was 32%.

## Other

(Cdn\$ millions)	2006	2005	2004
Block 51 Arbitration	(151)	–	–
Business Interruption Insurance Proceeds	154	2	10
Gain on Dilution of Interest in Chemicals Business	–	193	–
Gain on Disposition of Oil and Gas Assets included as Discontinued Operations	–	225	–
Increase (Decrease) in Fair Value of Crude Oil Put Options	(11)	(196)	56

During the year, 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 agreed to settle the arbitration by agreeing to pay Occidental US\$135 million as monetary damages. No further amounts are expected to be payable under the settlement.

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

As a result of the sale of our chemicals business to the Canexus Limited Partnership in 2005, we recorded a gain on the dilution of our interest from 100% to 61.4% of \$193 million. Our gain on the 2005 sale of Canadian oil and gas properties in Alberta, British Columbia and Saskatchewan was \$225 million.

Following our North Sea acquisition in late 2004, we purchased put options on 60,000 bbls/d of oil production for 2005 and 2006 to ensure base cash flow in those years while we invest in our major development projects. These options created an average floor price for this production of US\$43.17/bbl in 2005 and US\$38.17/bbl in 2006. Accounting rules require that these options be recorded at fair value throughout their term. As a result, changes in forward crude oil prices cause gains or losses to be recorded on these options at each period end. A gain of \$56 million was recorded in the fourth quarter of 2004, bringing the fair value of these options to \$200 million. During 2005, a significant increase in forward crude prices reduced the value of these options by \$196 million. Strong WTI prices in 2006 reduced the market value of these remaining options to nil and we expensed \$4 million in 2006 as a result.

During 2006, we purchased put options on approximately 105,000 bbls/d of our 2007 crude oil production. These options establish a WTI floor price of US\$50/bbl on these

volumes, are settled annually and provide a base level of price protection without limiting our upside to higher prices. The put options were purchased for \$26 million and are carried at fair value. We recorded a loss of \$7 million during the year for the decrease in fair value.

## OUTLOOK FOR 2007

In 2007, we plan to invest \$2.9 billion in capital projects. Approximately 34% of this capital will be invested in development projects, which include Long Lake, coalbed methane in Canada, Ettrick in the North Sea, and Wrigley and Tobago in the Gulf of Mexico. We are also directing 14% of our 2007 capital to early-stage development projects expected to contribute production and cash flow growth beyond 2007. These include Knotty Head, Alaminos Canyon Block 856 (Great White West) and Ringo in the Gulf of Mexico, additional phases of oil sands in the Athabasca region and Block 222, offshore West Africa. We have allocated 24% of our capital to exploration opportunities in our growth areas. The remaining 28% of the 2007 capital will be invested to exploit potential in our existing producing assets and in other corporate assets.

Details of our 2007 capital investment program are included in the Capital Investment section of the MD&A.

## Daily Production

We expect to grow annual production rates after royalties approximately 50% compared to 2006 to between 230,000 and 260,000 boe/d (275,000 and 305,000 boe/d before royalties). Our Buzzard development came on stream early January 2007 and we expect to achieve peak rates of 85,000 boe/d during the second quarter of 2007. Other contributions to our expected growth in 2007 are from the Gulf of Mexico, a full year of production from the Stage 3 expansion at Syncrude and bitumen production from Long Lake. Our annual production for 2007 is expected to be:

## 2007 Estimated Production

(mboe/d)	2007 Estimated Production		2006 Production	
	Before Royalties	After Royalties	Before Royalties	After Royalties
United States	45 – 55	38 – 48	36	31
United Kingdom	90 – 100	90 – 100	20	20
Yemen	60 – 75	35 – 45	93	52
Canada	45 – 50	38 – 42	38	31
Syncrude	20 – 25	18 – 20	19	17
Other International	6 – 7	5 – 6	6	5
<b>Total</b>	<b>275 – 305</b>	<b>230 – 260</b>	<b>212</b>	<b>156</b>

## Cash Flow and Sensitivities

We expect to generate more than \$3.3 billion in cash flow from operating activities in 2007 (before site restoration and geological and geophysical expenditures), assuming the following:

WTI (US\$/bbl)	50.00
NYMEX Natural Gas (US\$/mmbtu)	6.00
Oil & Gas and Syncrude Operating Costs (Cdn\$/boe)	8.00
US to Canadian Dollar Exchange Rate	0.88

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

(Cdn\$ millions)	
WTI—US\$1/bbl Change above US\$50	73
WTI—US\$1/bbl Change below US\$50	42
NYMEX Natural Gas—US \$1.00/mcf Change	66
Exchange Rate—\$0.01 Change	35

## LIQUIDITY AND CAPITAL RESOURCES

### Capital Structure

(Cdn\$ millions)	2006	2005
<b>Net Debt</b> <sup>1</sup>		
Bank Debt	1,410	171
Public Senior Notes	2,885	2,980
Senior Debt	4,295	3,151
Subordinated Debt	536	536
Total Debt	4,831	3,687
Less: Cash and Cash Equivalents	(101)	(48)
<b>Total Net Debt</b>	<b>4,730</b>	<b>3,639</b>
<b>Shareholders' Equity</b> <sup>2</sup>	<b>4,636</b>	<b>3,996</b>

Notes:

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

<sup>2</sup> At January 31, 2007, there were 262,830,108 common shares and US\$460 million of unsecured subordinated securities outstanding. These subordinated securities may be redeemed by issuing common shares at our option after November 8, 2008. The number of shares issuable depends on the common share price on the redemption date.

## 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, capital investment activities and disposition programs. We ended the year with net debt of \$4.7 billion, an increase of \$1.1 billion from 2005. In 2006, we invested over \$3.4 billion in capital projects, with

more than 50% of this at Long Lake and Buzzard. These major projects did not contribute to cash flow in 2006 but will start to contribute in 2007 and beyond. We financed our 2006 capital program with cash flow from operating activities and borrowed US\$925 million under our term credit facilities.

The year-over-year change in our net debt results from:

(Cdn\$ millions)	2006	2005
Capital Investment	3,408	2,638
Cash Flow from Operating Activities	(2,374)	(2,143)
Excess of Capital Investment over Cash Flow	1,034	495
Net Proceeds on Disposition of Assets	(27)	(911)
Net Proceeds from Canexus Initial Public Offering	–	(301)
Dividends on Common Shares	52	52
Issue of Common Shares	(48)	(58)
Foreign Exchange Translation of US-dollar Debt and Cash	31	(113)
Other	49	190
<b>Increase (Decrease) in Net Debt</b>	<b>1,091</b>	<b>(646)</b>

The change in our net debt has increased our leverage levels as reflected in following ratios:

(times)	2006	2005	2004
Net Debt to Cash Flow from Operating Activities	2.0	1.7	2.7
Interest Coverage <sup>1</sup>	9.6	9.7	11.9

Note:

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

Our business strategy is focused on value-based growth through full-cycle exploration and development, supplemented by strategic acquisitions when appropriate. We have leveraged our balance sheet in the past to accomplish our growth strategy, as most of our projects have long-cycle times, requiring significant amounts of capital to be invested prior to generating cash flows. Historically, we have been successful with this strategy as we used leverage 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;

- build our first phase of Long Lake, scheduled to be on stream in late 2007; and
- fund remaining development capital.

Each time, we exceeded our internal net debt to cash flow target band; however, we successfully brought our leverage down through asset sales and incremental cash flows. In 2006, we again increased our leverage levels as a result of capital expenditures on our major development projects at Buzzard and Long Lake. In 2007, we anticipate reducing our net debt to cash flow from operating activities ratio using cash flows from our Buzzard operations, as well as our Long Lake project, expected to come on stream in 2007.

## Change in Working Capital

(Cdn\$ millions)	2006	2005	Increase/ (Decrease)
Cash and Cash Equivalents	101	48	53
Restricted Cash and Margin Deposits	197	70	127
Accounts Receivable	2,951	3,151	(200)
Inventories and Supplies	786	504	282
Future Income Tax Assets	479	–	479
Accounts Payable and Accrued Liabilities	(3,879)	(3,727)	(152)
Other	(1)	(17)	16
<b>Total</b>	<b>634</b>	<b>29</b>	<b>605</b>

Lower natural gas prices reduced our year end accruals for our marketing accounts receivable and accounts payable. This has been offset by higher prices in crude oil markets. We expanded our crude oil physical and financial trading activities to capture market gains. This expanded activity increased our marketing accounts receivable and accounts payable. We took advantage of lower natural gas prices and expanded our gas storage inventories by 27 bcf during the year. Volatile gas markets also increased the value of our derivative contract assets and liabilities.

Our accounts payable and accrued liabilities have increased since 2005 from higher accrued stock-based compensation obligations as a result of our strong share price, higher accruals related to our capital investment programs and our accrual related to the Block 51 settlement. We have reclassified \$479 million of future income tax assets to current assets. This represents tax loss carry-forward balances in our UK operations that we expect to use in the next twelve months now that Buzzard is on stream.

## Liquidity

We generally rely on operating cash flows to fund capital requirements and provide liquidity. We build our opportunity portfolio to provide a balance of short-term, mid-term, and longer-term growth. Given the long cycle-time of some of our

development projects and the volatility of commodity prices, it is not unusual in any given year for capital expenditures to exceed our cash flow. In addition, we require liquidity for our energy marketing business. Accordingly, we maintain significant committed credit facilities. At December 31, 2006, we had committed term credit facilities of \$3.6 billion that are available until 2011. At year end, \$1,078 million was drawn on these facilities and \$294 million of these facilities were utilized to support letters of credit. We also had \$632 million of uncommitted, unsecured credit facilities, of which \$158 million was drawn at year end and \$252 million was utilized to support letters of credit.

From time to time, we access the capital markets to meet our financing needs. We also use various financial instruments to minimize our exposure to fluctuations in commodity prices and foreign exchange. For example, we purchased WTI put options for 2007 to mitigate cash flow volatility. Overall, we manage our capital structure to maintain flexibility so we can fund our capital programs throughout the highs and lows of the price cycles inherent in 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. We borrow or issue equity to fund investment requirements that exceed our operating cash flow.

(Cdn\$ millions)	2006	2005	2004	2003	2002
Cash Flow from Operating Activities	2,374	2,143	1,606	1,405	1,250
Cash Flow from Investing Activities	(3,388)	(1,864)	(4,013)	(1,219)	(1,569)
Surplus (Deficiency)	(1,014)	279	(2,407)	186	(319)
Cash Flow from Financing Activities	1,081	(274)	1,426	1,006	329
	<b>67</b>	<b>5</b>	<b>(981)</b>	<b>1,192</b>	<b>10</b>

In 2002, we began to invest significantly in two deep-water Gulf of Mexico projects (Aspen and Gunnison), our Syncrude expansion and our Long Lake project. We accessed public debt markets in 2002 to fund these investments. In 2003, Aspen contributed significantly to our cash flow and 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 our cash flow and the 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 our cash flow from operating activities to fund our capital program.

Our marketing business also requires liquidity to support its asset-based trading strategy. 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 posting of collateral when adverse credit-related events occur, such as a reduction in credit ratings. 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 in the event of reductions in our credit ratings.

### Future Liquidity

Our future liquidity is primarily dependent on cash flows generated from our operations, existing committed credit facilities and our ability to access debt and equity markets. Assuming WTI of US\$50/bbl, we expect our 2007 cash flow to exceed our capital investment program and dividend requirements by more than \$300 million. In July 2007, we are required to repay \$150 million of medium term notes that become due,

however, we plan to fund this with our term credit facilities.

Our cash flow is sensitive to changes in commodity prices and exchange rates. For 2007, we expect cash flow of approximately \$3.3 billion (before remediation and geological and geophysical expenditures) assuming:

WTI (US\$/bbl)	50.00
NYMEX Natural Gas (US\$/mmbtu)	6.00
US to Canadian Dollar Exchange Rate	0.88

Changes in commodity prices and exchange rates will impact our cash flow and borrowing requirements. The impact of a variance in any one of the above assumptions on our cash flow is described in the Outlook for 2007 section on page 64.

**For 2007, we expect cash flow of  
approximately \$3.3 billion.**

We are in the midst of a number of development projects that require capital to bring them on stream. We anticipate that we will spend an additional \$500 million in 2007 to bring the first phase of Long Lake on stream. In addition, we expect to spend \$200 million in 2007 on furthering our coalbed methane projects in central Alberta and \$235 million to complete the Ettrick development in the North Sea by mid 2008.

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 undrawn committed credit facilities to manage this risk. In addition to our operating cash flows and our undrawn committed credit facilities, we have a US\$1.5 billion shelf prospectus available in the US and Canada.

At December 31, 2006, the average term to maturity of our long-term debt was 16.6 years. We have the following short and long-term debt maturities during the next five years:

(Cdn\$ millions)	2007	2008	2009	2010	2011
Uncommitted Credit Facilities	158	–	–	–	–
Term Credit Facilities <sup>1</sup>	–	–	–	–	1,078
Canexus LP Term Credit Facilities	–	–	–	174	–
Debentures	–	–	–	–	–
Medium Term Notes	150	125	–	–	–
<b>Total</b>	<b>308</b>	<b>125</b>	<b>–</b>	<b>174</b>	<b>1,078</b>

Note:

<sup>1</sup> \$3.6 billion available until 2011.

With our expected cash flow streams, commodity price and hedging strategies, current levels of liquidity, and access to debt and equity markets, we expect to be able to fund our planned capital programs, dividend requirements and debt repayments, or meet other obligations that may arise from our oil and gas, chemicals and marketing operations.

In 2006 we declared common share dividends of \$0.20 per share (2005—\$0.20, 2004—\$0.20). We expect to declare common share dividends of \$0.20 per share in 2007.

### 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
Short-Term and Long-Term Debt	4,831	308	125	1,252	3,146
Interest on Long-Term Debt	4,859	215	406	403	3,835
Operating Leases <sup>1</sup>	752	44	236	240	232
Capital Leases	119	5	10	10	94
Energy Commodity Contract Liabilities	524	325	191	8	—
Transportation and Storage Commitments <sup>1</sup>	927	424	262	123	118
Work Commitments and Purchase Obligations <sup>2</sup>	1,460	663	419	218	160
Asset Retirement Obligations	1,770	21	42	34	1,673
<b>Total</b>	<b>15,242</b>	<b>2,005</b>	<b>1,691</b>	<b>2,288</b>	<b>9,258</b>

*Notes:*

<sup>1</sup> Payments for operating leases and transportation and storage commitments are deducted from our cash flow from operating activities.

<sup>2</sup> Some of these payments relate to work commitments cancellable at our option 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, 2006 Consolidated Balance Sheet.
- Operating leases include the minimum lease payment obligations associated with leases for office space, rail cars, vehicles and our processing agreement that allows our Aspen production to flow through Shell's processing facilities at the Bullwinkle platform. The terms of the processing agreement give Shell an annual option to take payment in cash or in kind. For 2007, Shell has elected to take payment in kind, so the 2007 obligation has been excluded from this table. Instead, it is shown as a royalty and excluded from reserves and production.
- Capital leases include pipeline commitments primarily related to future 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, 2006. For certain contracts, we may net settle.
- Work commitments include non-discretionary capital spending related to drilling, seismic, construction of facilities and other development commitments in our international operations, and includes Long Lake (\$157 million) and the Ettrick development in the North Sea (\$233 million). The timing of certain payments is difficult to determine with certainty. The table has been prepared using our best estimates; the remainder of our 2007 capital investment is discretionary.
- We also have included work commitments relating to drilling rigs, which have been contracted to work for us in the North Sea and Gulf of Mexico, totalling \$414 million over the next five years.

- We have \$1,770 million of undiscounted asset retirement obligations after inflation. As of December 31, 2006, the discounted value (\$704 million) of these estimated obligations has been provided for in our Consolidated Financial Statements (including \$21 million of current liabilities). The timing of any payments is difficult to determine with certainty, and the table has been prepared using our best estimates.
- We have unfunded obligations under our defined benefit pension plans of \$122 million (Nexen—\$67 million; Canexus—\$8 million; Syncrude—\$47 million). Our obligations for Nexen and Canexus include \$54 million that is unfunded as a result of statutory limitations. These obligations are backed by irrevocable letters of credit.
- We have excluded obligations on our tandem option and stock appreciation rights programs as the amount and timing of cash payments are indeterminable.
- We have excluded our normal purchase arrangements as they are discretionary and are reflected in our expected cash flow from operating activities and our expected capital expenditures for 2007.
- We have excluded our future income tax liabilities as the amount and timing of any cash payments for income taxes are based primarily on taxable income for each fiscal year in the various jurisdictions in which we operate.

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 these matters 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). In addition, Moody's and DBRS currently rate our outlook as stable while S&P has a positive outlook. 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 marketing group enters into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. The agreements normally require posting of collateral when adverse credit-related events occur such as a reduction in credit ratings. Based on the contracts in place and commodity prices at December 31, 2006, we could be required to post collateral of up to \$1,149 million if we were downgraded to non-investment grade. These obligations are already reflected on our balance sheet. The posting of collateral merely accelerates the payment of such amounts. Just as we may be required to post collateral in the event of a downgrade below investment grade, we have similar provisions in many of our contracts that allow us to demand certain counterparties post collateral for amounts owing to 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 15 to the Consolidated Financial Statements in Item 8, which is incorporated herein by reference. At December 31, 2006, we had outstanding letters of credit amounting to \$294 million and \$252 million supported by our committed term credit facilities and our uncommitted credit facilities, respectively.

#### **Contingencies**

We have no contingencies that would have a material adverse effect on our liquidity, consolidated financial position or results of operations. See Note 15 to the Consolidated Financial Statements in Item 8, which is incorporated herein by reference for a discussion of our contingencies.

### CRITICAL ACCOUNTING ESTIMATES

We make estimates and assumptions that affect the reported amounts of our assets and liabilities and the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements and our revenues and expenses during the reporting period. Our management reviews these estimates, including those related to accruals, litigation, environmental and asset retirement obligations, income taxes, derivative contract assets and liabilities 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 judgements 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 estimating the quantities of proved oil and natural 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. 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 in 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 assessed (i.e. either evaluated or audited) annually by independent qualified reserves consultants. Given that reserve estimates are based on numerous assumptions, interpretations and judgements, 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.

At December 31, 2006, we had 98% of our oil and gas and Syncrude reserves before royalties (98% after royalties) assessed by independent engineers. DeGolyer and MacNaughton performed evaluations of our proved reserves for each of the Masila Block (Yemen), Block 51 (Yemen), Usan (Nigeria) and our United Kingdom properties. McDaniel & Associates Consultants Ltd. (McDaniel) prepared one evaluation comprising a portion of our Canadian conventional, coalbed methane and Long Lake properties. An evaluation is a process whereby a qualified reserves evaluator prepares their estimate of the remaining quantities of oil and gas reserves by assessing and interpreting all available data on a reservoir to allow them to assess whether our estimates are reasonable. McDaniel performed an audit of our Syncrude interest. Ryder Scott Company audited a portion of our US Gulf of Mexico shelf properties. William M. Cobb & Associates, Inc. audited our US Gulf of Mexico deep-water properties. An audit is a process whereby an independent qualified reserves auditor reviews our estimates, supporting work papers and other data as they feel is necessary to prepare their estimate of remaining quantities of oil and gas reserves to allow them to assess whether our estimates are reasonable.

The board of directors has established a Reserves Review Committee (Reserves Committee) to assist the board and the Audit and Conduct Review Committee to oversee the annual review of our oil and gas reserves and related disclosures. The Reserves Committee is comprised of three or more directors, the majority of whom are independent, and each being 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 each of 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.

The Reserves Committee has reviewed Nexen's procedures for preparing the reserves estimates and related disclosures. It has reviewed the information with management, and met with the internal qualified reserves evaluator and the independent qualified reserves consultants. As a result of this, 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 2006, \$169 million of our total \$289 million spent on exploration drilling was expensed. If none of our exploration drilling had been successful, our net income would have decreased by \$120 million.
- 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 2006, oil and gas depletion of \$741 million 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 \$74 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.

### **Property, Plant and Equipment—Impairment**

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, this might include falling oil and gas prices, a significant negative revision to our reserves estimates, changes in operating and capital costs, or significant

or adverse political 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 flows for a property are less than the carrying amount of that property, we calculate its fair value using a discounted cash flow approach. The property is then written down to its fair value. We assessed our oil and gas assets for impairment at the end of 2006 and recorded an impairment charge of \$93 million, primarily related to two natural gas producing properties in the Gulf of Mexico.

Cash flow estimates for our impairment assessments require assumptions about two primary elements—future prices and reserves. Our estimates of future prices require significant judgements 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\$18/bbl to US\$79/bbl and US\$2/mmbtu to US\$16/mmbtu, respectively. Our forecasts for oil and gas revenues are based on prices derived from a consensus of future price forecasts amongst industry analysts and our own assessments. Our estimates of future cash flows generally assume our long-term price forecast and forecast operating and development costs. 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 except our chemicals and energy marketing businesses.

It is difficult to determine and assess the impact of a decrease in our proved reserves on our impairment tests. The relationship between the reserves 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 reserves estimate decrease would have on our assessment of impairment.

#### **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. Estimating our future asset retirement obligations requires us to make estimates and judgments with respect to activities that will occur many years into the future. In addition, the ultimate financial impact

of environmental laws and regulations is not always clearly known and cannot be reasonably estimated as standards evolve in the countries in which we operate.

We record asset retirement obligations in our Consolidated Financial Statements by discounting the present 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 with respect to ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement and expected changes in legal, regulatory, environmental and political environments. The asset retirement obligations we have recorded result in an increase to the carrying cost of our property, plant and equipment. The obligations are accreted 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.

It is difficult to determine the impact of a change in any one of our assumptions. As a result, we are unable to provide a reasonable sensitivity analysis of the impact a change in our assumptions would have on our financial results.

#### **Business Combination—Purchase Price Allocation**

During the fourth quarter of 2004, we acquired a company operating and exploring oil and gas properties located in the North Sea. We accounted for this acquisition using the purchase method of accounting. Under this method, we were required to record on our Consolidated Balance Sheet the estimated fair values of the acquired company's assets and liabilities at the acquisition date. The excess of the purchase price over the fair values of the tangible and intangible net assets acquired was recorded as goodwill.

We made various assumptions in determining the fair values of the acquired company's assets and liabilities. The most significant assumptions and judgments relate to the estimation of the fair value of the oil and gas properties. To determine the fair value of these properties, we estimated (a) oil and gas reserves in accordance with our reserve standards, (b) additional reserves potential and (c) future prices of oil and gas.

Our reserve estimates were based on the work performed by our engineers and outside consultants. The judgments associated with these estimated reserves are described earlier in our critical accounting estimates discussion entitled "Oil and

Gas Accounting—Reserves Determination”. Our estimates of future prices were based on prices derived from a consensus of future price forecasts amongst industry analysts and our own assessments. The judgments associated with these estimates are described earlier in our critical accounting estimates discussion entitled “Oil and Gas Accounting—Impairment”.

We applied our estimated future prices to the estimated reserves quantities acquired, and we estimated future operating and development costs, to arrive at estimated future net revenues for the properties acquired. For proved properties, we discounted the future net revenues using after-tax discount rates. The same principles were applied in arriving at the fair value of unproved properties acquired. These unproved properties generally represent the value of the probable and possible reserves. Because of their very nature, probable and possible reserve estimates are more imprecise than those of proved reserves. To compensate for the inherent risk of estimating and valuing unproved reserves, an appropriate risk-weighting factor was applied to the discounted future net revenues of the probable and possible reserves in each particular instance.

If the fair value allocated to oil and gas properties acquired had been decreased by \$50 million, future income tax liabilities would have decreased by \$20 million and goodwill would have increased by \$30 million.

#### Future 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 our income tax provision 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 made adequate provision 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.

## NEW ACCOUNTING PRONOUNCEMENTS

### Canadian Pronouncements

In an effort to harmonize Canadian GAAP with US GAAP, the Canadian Accounting Standards Board (AcSB) has issued sections:

- 1530, *Comprehensive Income*;
- 3855, *Financial Instruments—Recognition and Measurement*; and
- 3865, *Hedges*.

Under these new standards, all financial assets should be measured at fair value with the exception of loans, receivables and investments that are intended to be held to maturity and certain equity investments, which should be measured at cost. Similarly, all financial liabilities should be measured at fair value when they are held for trading or they are derivatives.

Gains and losses on financial instruments measured at fair value will be recognized in the income statement in the periods they arise with the exception of gains and losses arising from:

- financial assets held for sale, for which unrealized gains and losses are deferred in other comprehensive income until sold or impaired; and
- certain financial instruments that qualify for hedge accounting.

Sections 3855 and 3865 make use of “other comprehensive income”. Other comprehensive income comprises revenues, expenses, gains and losses that are recognized in comprehensive income, but are excluded from net income. Unrealized gains and losses on qualifying hedging instruments, translation of self-sustaining foreign operations, and unrealized gains or losses on financial instruments available for sale will be included in other comprehensive income and reclassified to net income when realized. Comprehensive income and its components will be a required disclosure under the new standard.

These new standards are effective for fiscal years beginning on or after October 1, 2006 and early adoption is permitted. Adoption of these standards as at December 31, 2006 would have the following impact on our Consolidated Financial Statements:

(Cdn\$ millions)	Increase/ (Decrease)
Accounts Receivable	25
Future Income Tax Liabilities	7
Cumulative Foreign Currency Translation Adjustment	161
Accumulated Other Comprehensive Income	(143)

In March 2006, the CICA's Emerging Issues Committee (EIC) issued Abstract 160, *Stripping Costs Incurred in the Production Phase of a Mining Operation* (EIC-160). EIC-160 outlines accounting for overburden and mine waste materials removed in the process of accessing mineral deposits according to the benefit received by the entity. Generally, stripping costs should be accounted for as variable production costs and included in the costs of inventory produced in the period the stripping costs are incurred. If it can be shown that the stripping was for betterment of the mineral property, stripping costs should be capitalized. The standard outlines the requirement for amortization of capitalized stripping costs as well as a reconciliation of stripping costs incurred in the production phase. EIC-160 is effective for fiscal years beginning on or after July 1, 2006. We do not expect the adoption of EIC-160 will have any material impact on our results of operations or financial position.

In July 2006, the EIC issued Abstract 162, *Stock-Based Compensation for Employees Eligible to Retire Before the Vesting Date* (EIC-162). EIC-162 provides that if an employee is eligible to retire on the grant date of a stock-based award, related compensation expense is recognized in full at that date as there is no ongoing service requirement to earn the award. In addition, if the employee becomes eligible to retire during the vesting period, related compensation expense is recognized over the period from the grant date to the retirement eligibility date on a graded vesting basis. EIC-162 is effective for interim and annual periods ending on or after December 31, 2006. We adopted EIC-162 on a retroactive basis in the fourth quarter of 2006. For the year ended December 31, 2006, the impact of adopting EIC-162 decreased general and administrative expense by \$9 million, increased provision for future income taxes by \$3 million, increased net income \$6 million, and increased basic and diluted earnings per share by \$0.02/share. For the year ended December 31, 2005, the impact of adopting EIC-162 increased general and administrative expense by \$17 million, decreased provision for future income taxes by \$5 million, reduced net income by \$12 million, and reduced basic and diluted earnings per share by \$0.05/share. The impact on the year ended December 31, 2004 was immaterial.

In December 2006, the AcSB issued two new Sections in relation to financial instruments: Section 3862, *Financial Instruments – Disclosures*, and Section 3863, *Financial Instruments – Presentation*. Both sections will become effective for annual and interim periods beginning on or after October 1, 2007 and will require increased disclosure of financial instruments.

In December 2006, the AcSB issued Section 1535, *Capital Disclosures*, requiring disclosure of information about an entity's capital and the objectives, policies, and processes for managing capital. The standard is effective for annual periods beginning on or after October 1, 2007.

### US Pronouncements

On January 1, 2006, we adopted FASB Statement 123 (revised), *Share-Based Payment* (Statement 123(R)) using the modified-prospective approach and graded-vesting amortization. Under Statement 123(R), our tandem options and stock appreciation rights are considered liability-based stock compensation plans. Under the modified-prospective approach, no amounts are restated in prior periods. Upon adoption of Statement 123(R), we recorded a cumulative effect of a change in accounting principle of \$2 million. This amount was recorded in general and administrative expenses during the first quarter of 2006 in our US GAAP Consolidated Statement of Income.

Prior to the adoption of Statement 123(R), we accounted for our liability-based stock compensation plans in accordance with FASB Interpretation 28, *Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans* (the intrinsic-value method). Accordingly, obligations were accrued on a graded-vesting basis and represented the difference between the market value of our common shares and the exercise price of underlying options and rights. Under Statement 123(R), obligations for liability-based stock compensation plans are measured at their fair value, and are re-measured at fair value in each subsequent reporting period.

Consistent with Statement 123(R), we account for any stock options that do not include a cash feature (equity-based stock compensation plans), using the fair-value method.

The impact of adopting Statement 123(R) on our results for the year ended December 31, 2006 is as follows:

(Cdn\$ millions, except per share amounts)	Prior to Adoption of FAS 123(R)	After Adoption of FAS 123(R)	Increase/ (Decrease)
Income from Continuing Operations before Income Taxes—US GAAP	1,306	1,264	(42)
Net Income—US GAAP	608	579	(29)
Basic Earnings per Common Share—US GAAP (\$/share)	2.32	2.21	(0.11)
Diluted Earnings per Common Share—US GAAP (\$/share)	2.26	2.15	(0.11)

We recognize stock-based compensation expense for our retired and retirement-eligible employees over an accelerated graded vesting period in accordance with the provisions of Statement 123(R) for stock-based awards granted to employees after December 31, 2005. For stock-based awards granted prior to the adoption of Statement 123(R), stock-based compensation expense for our retired and retirement-eligible employees is recognized over a graded vesting period. If we applied the accelerated vesting provisions of Statement 123(R) to stock-based awards granted to our retired and retirement-eligible employees prior to the adoption of Statement 123(R), there would be no material change to our stock-based compensation expense for the three years ended December 31, 2006.

In February 2006, the FASB issued Statement 155, *Accounting for Certain Hybrid Instruments*, which amends Statement 133, *Accounting for Derivative Instruments and Hedging Activities*, and Statement 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*. Statement 155 permits fair value re-measurement of hybrid financial instruments that contain an embedded derivative that otherwise would require bifurcation from its host contract in accordance with Statement 133. Statement 155 also clarifies and amends certain other provisions of Statement 133 and Statement 140. This statement is effective for all financial instruments acquired or issued in fiscal years beginning after September 15, 2006. We do not expect the adoption of this statement will have a material impact on our results of operations or financial position.

In July 2006, FASB issued FIN 48 *Accounting for Uncertainty in Income Taxes* with respect to FAS 109 *Accounting for Income Taxes* regarding accounting for and disclosure of

uncertain tax positions. FIN 48 seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement related to accounting for income taxes and is effective for fiscal years beginning after December 15, 2006. Adoption of this standard is expected to increase our future income tax liabilities by no more than \$30 million and decrease our retained earnings by a corresponding amount.

In September 2006, FASB issued Statement 157, *Fair Value Measurements*. Statement 157 defines fair value, establishes a framework for measuring fair value under US generally accepted accounting principles and expands disclosures about fair value measurements. This statement is effective for fiscal years beginning after November 15, 2007. We do not expect the adoption of this statement will have a material impact on our results of operations or financial position.

In September 2006, FASB issued Statement 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*. Statement 158 requires an employer to recognize the over-funded or under-funded status of a defined benefit post-retirement plan on the balance sheet as an asset or liability and to recognize changes in funded status through comprehensive income. This statement also requires measurement of the funded status of a plan as of the balance sheet date. The recognition and disclosures under Statement 158 are required for fiscal years ending after December 15, 2006 while the new measurement date is effective for fiscal years ending after December 15, 2008. We adopted the recognition and disclosure provisions at December 31, 2006 in our US GAAP presentation. We do not expect the adoption of the change in measurement date in 2008 to have a material impact on our results of operations or financial position.

## 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 are commodities which are sensitive to numerous worldwide factors, 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 oil and gas exploration and development.

Our crude oil prices are based on various reference prices,

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

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

In 2006, WTI averaged US\$66.22/bbl reaching a high of US\$78.40/bbl and a low of US\$54.86/bbl. NYMEX natural gas prices averaged US\$6.99/mmbtu in 2006, reaching a high of US\$11.00/mmbtu and a low of US\$4.05/mmbtu. Our sensitivities to commodity prices and the expected impact on our 2007 cash flow from operating activities and net income are as follows:

(Cdn\$ millions)	Cash Flow	Net Income
WTI—US\$1/bbl Change above US\$50	73	46
WTI—US\$1/bbl Change below US\$50	42	26
NYMEX Natural Gas—US\$1.00/mcf Change	66	56

These sensitivities to changes in benchmark prices for crude oil and natural gas are based on our estimated 2007 production levels for crude oil and natural gas and assume a Canadian/US dollar exchange rate of \$0.88. Our estimated crude oil and natural gas production range for 2007 is between 275,000 and 305,000 boe/d before royalties, of which natural gas represents approximately 18%.

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 2006, we purchased WTI put options to manage the commodity price risk exposure on a portion of our oil production in 2007, by establishing an annual average WTI floor price of US\$50/bbl on 105,000 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 \$0.88 in 2006 with a high of \$0.91 and a low of \$0.85.

Our sensitivities to the US dollar and the expected impact of a one cent change on our 2007 cash flow from operating activities, net income, capital expenditures and long-term debt are as follows:

(Cdn\$ millions)	Cash Flow	Net Income	Capital Expenditures	Long-Term Debt
<b>\$0.01 Change in US to Canadian Dollar</b>	35	12	19	31

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 2007. These estimates are based on a WTI price for crude oil of US\$50/bbl, a NYMEX natural gas price of US\$6/mmbtu, operating costs of \$8/boe and a Canadian/US dollar exchange rate of \$0.88.

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 foreign operations.

Our chemicals operations are exposed to changes in the US-dollar exchange rate as a portion of their sales are denominated in US-dollars. Canexus periodically purchases US-dollar call options to reduce this exposure. Under outstanding option contracts at December 31, 2006, Canexus had the right to sell US\$5 million monthly and purchase Canadian dollars at an exchange rate of US\$0.85 to January 10, 2007 and has the right to sell US\$5 million monthly and purchase Canadian dollars at an exchange rate of US\$0.87 for the period January 10, 2007 to July 11, 2007.

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 2007 cash flow from operating activities and net income is as follows:

(Cdn\$ millions)	Cash Flow	Net Income
<b>Interest Rates—1% change in rates</b>	9	6

Our sensitivity to changes in interest rates is based on 2007 estimated average floating rate debt of \$900 million and a Canadian/US dollar exchange rate of \$0.88.

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, 2006, fixed-rate borrowings comprised 73% (2005—95%) of our long-term

debt at an effective average rate of 6.3% (2005—6.3%). During the year, we periodically drew on our committed, unsecured, term credit facilities and at December 31, 2006, floating-rate debt comprised 27% (2005—5%) of our long-term debt at an effective average rate of 5.7% (2005—4.4%) reaching a high of 6.4% and a low of 4.25% during 2006.

We had no interest rate swaps outstanding in 2006 or 2005.

**TRADING****Commodity Price Risk**

Our marketing operation is involved in the marketing and trading of crude oil, natural gas, natural gas liquids and power through the use of physical purchase and sales contracts, as well as financial commodity contracts. These activities expose us to commodity price risk, as well as foreign currency risk and volatility within these markets. The marketing group actively manages this risk by utilizing energy-related futures, forwards, swaps and options, as well as currency swaps or forwards. The marketing operation also tries to take advantage of volatility within commodity markets and can establish net open commodity positions to take advantage of existing market conditions.

Volatility within our various markets can vary and changes over time. While this volatility gives us opportunities, it can also cause our results to vary significantly between periods. We attempt to manage associated risk and take on positions based on solid market intelligence, however, it is possible that we could incur financial loss.

Open positions exist where not all contracted purchases and sales terms have been matched. These net open positions allow us to generate income, but also expose us to risk of loss due to fluctuating market prices (market risk sensitivities in our portfolio). Open positions and derivative instruments expose us to other risks, including credit risk and liquidity risk. The inability to close out options, futures and forward positions could have an adverse impact on our ability to use derivative instruments to effectively hedge our portfolio and/or generate income from trading activities.

We control the level of market risk through daily monitoring of our energy-trading portfolio relative to:

- prescribed limits for Value-at-Risk (VaR);
- nominal size of commodity positions;
- stop loss limits; and
- stress testing.

VaR is a statistical estimate that is reliable when normal market conditions prevail. Our VaR calculation estimates the maximum probable loss, given a 95% confidence level, that we would incur if we were to unwind our outstanding positions over a two-day period. We estimate VaR using the Variance-Covariance method based on historical commodity price volatility and correlation inputs. 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.

If a severe market shock occurred, the key assumptions underlying our VaR estimate could be exceeded and the potential loss could be greater than our estimate. In May 2006, the methodology for estimating the input parameters for the VaR calculation for natural gas was revised to improve performance and stability under a range of normal and low probability market conditions. The new methodology produces VaR results substantially similar to the prior method with no material changes.

Stress testing complements our VaR estimate. It is used to quantify potential unexpected losses from low probability market movements. Credit VaR is reported separately from commodity VaR, and ranged between \$4 and \$5 million in 2006.

Our year end, annual high, annual low and annual average VaR amounts are as follows:

(Cdn\$ millions)	2006	2005	2004
<b>Value at Risk</b>			
Year End	26	24	21
High	33	28	42
Low	17	11	17
Average	23	21	29

Our board of directors has approved formal risk management policies for our energy trading activities. Market and credit risks are monitored daily by a risk group that operates independently and ensures compliance with our risk management policies. The Finance Committee of the board of directors and our Risk Management Committee monitor our exposure to the above risks and review the results of our energy trading activities regularly.

#### 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 energy traders, and are subject to normal industry credit risk. We take the following measures to reduce this risk:

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

- we 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;
- we set credit limits based on rating agency credit ratings and internal assessments based on company and industry analysis;
- we review counterparty credit limits regularly; and
- we 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. At December 31, 2006:

- over 98% of our credit exposures were investment grade; and
- only 2 counterparties individually made up more than 5% of our credit exposure. Both were investment grade.

### 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*, are forward-looking statements<sup>1</sup>. Forward-looking statements are generally identifiable by terms such as *anticipate, believe, intend, plan, expect, estimate, budget, outlook* or other similar words, and include statements relating to future production associated with our Coalbed Methane, Long Lake, and West Africa projects and future capital investment plans.

These 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. These risks, uncertainties and other factors include, among others:

- market prices for oil, natural gas and chemicals 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 that increase taxes or royalties, change environmental and other laws and regulations;
- renegotiations of contracts;
- results of litigations, arbitration or regulatory proceedings; and
- political uncertainty, including actions by insurgent or other armed groups or other conflict, including conflict between states.

The above items 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 are interdependent and management's future course of action depends upon our assessment of all information available at that time. 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 operations in Yemen;
- future capital expenditures and their allocation to exploration and development activities;
- future asset dispositions;
- future sources of funding for our capital program;
- possible commerciality, development plans or capacity expansions;
- future ability to execute dispositions of assets or businesses;
- future debt levels;
- future cash flows and their uses;
- future drilling of new wells;
- ultimate recoverability of reserves;
- expected finding and development costs;
- expected operating costs;
- future demand for chemicals products;
- future expenditures and future allowances relating to environmental matters; and
- dates by which certain areas will be developed or will come on stream.

We believe that any forward-looking statements made are reasonable based on information available to us on the date such statements were made. However, no assurance can be given as to future results, levels of activity and achievements. Except to the extent required by law, we undertake no obligation to update publicly or revise any forward-looking statements contained in this report. All subsequent forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements.

*Note:*

<sup>1</sup> *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.*

### SPECIAL NOTE TO CANADIAN INVESTORS

Nexen is an SEC registrant and a Form 10-K and related forms filer. Therefore, our reserves estimates and securities regulatory disclosures follow SEC requirements. In 2003, Canadian regulatory authorities adopted *National Instrument 51-101—Standards of Disclosure for Oil and Gas Activities* (NI 51-101) which prescribes that Canadian companies follow

certain standards for the preparation and disclosure of reserves and related information. We have been granted the following exemptions permitting us to:

- substitute our SEC disclosures for much of the annual disclosure required by NI 51-101;
- prepare our reserves estimates and related disclosures in accordance with SEC 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;
- dispense with the requirement to have our reserves estimates and the *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein*, included in the Supplementary Financial Information, evaluated or audited by independent qualified reserves evaluators; and
- not disclose certain prescribed information pertaining to prospects if such disclosures would result in the contravention of a legal obligation, would likely be detrimental to our competitive interests or the information does not exist.

As a result of these exemptions, 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 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 also 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 246 million barrels before royalties of proved bitumen reserves (219 million barrels after royalties) under SEC requirements, whereas under NI 51-101 we would have recognized 200 million barrels before royalties of proved synthetic reserves (185 million barrels after royalties); and
- 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.

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

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.