



## management's **discussion**

With significant production growth and strong oil prices, cash flow from operating activities reached a record \$2.8 billion.

## 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 13, 2008.

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.

Notes:

- 1 Investors should read the Special Note Regarding Forward-Looking Statements on Page 75.
- 2 Canadian investors should read the Special Note to Canadian Investors on page 76 which highlights differences between our reserve estimates and related disclosures that are otherwise required by Canadian regulatory authorities.

	Page
Executive Summary	39
Capital Investment	40
Financial Results	
Year-to-Year Change in Net Income	44
Oil & Gas and Syncrude Production	45
Commodity Prices	48
Operating Expenses	50
Depreciation, Depletion, Amortization and Impairment	52
Exploration Expense	53
Oil & Gas and Syncrude Netbacks	55
Energy Marketing	56
Chemicals	59
Corporate Expenses	60
Outlook for 2008	62
Liquidity and Capital Resources	63
Critical Accounting Estimates	68
New Accounting Pronouncements	71
Quantitative and Qualitative Disclosures about Market Risk	72

**EXECUTIVE SUMMARY**

(Cdn\$ millions)	2007	2006	2005
Net Income	1,086	601	1,140
Earnings per Common Share, Basic (\$/share)	2.06	1.15	2.19
Cash Flow from Operating Activities	2,830	2,374	2,143
Production before Royalties (mboe/d) <sup>1</sup>	254	212	242
Production after Royalties (mboe/d)	207	156	173
Capital Investment, including Acquisitions	3,401	3,408	2,638
Net Debt <sup>2</sup>	4,404	4,730	3,639
Average Foreign Exchange Rate (Canadian to US dollar)	0.93	0.88	0.83
Proved Oil and Gas Reserves before Royalties (mmbøe) <sup>3</sup>	734	725	468
Proved Oil and Gas Reserves after Royalties (mmbøe) <sup>3</sup>	650	637	393
Proved Syncrude Reserves before Royalties (mmbøe) <sup>3</sup>	324	324	318
Proved Syncrude Reserves after Royalties (mmbøe) <sup>3</sup>	267	274	264

## 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.

Our strategy is to grow long-term value for shareholders responsibly. We started to monetize this value by bringing Buzzard on stream early in 2007 and expect more to follow as Ettrick and the first phase of Long Lake come on stream in 2008. We also added value by increasing our reserves and capturing additional acreage in attractive growth areas like the US Gulf of Mexico, Norway, and shale gas and oil sands in western Canada. Higher net income and cash flow from operating activities in 2007 were due to a 33% increase in production after royalties (20% increase before royalties) and strong commodity prices. Although WTI rose 9% from 2006, a stronger Canadian dollar limited the increase in our realized crude oil prices. This was offset by changes in our production mix as we are transitioning to higher-value crude oil from Buzzard. Our average realized oil and gas price increased 9% over last year to \$68.46/boe.

Our share of production from Buzzard averaged more than 64,000 boe/d in 2007. While commissioning of all systems took longer than expected, the facilities have produced as high as 220,000 boe/d (95,000 boe/d net to us) during the year, higher than originally expected. Looking forward, with a full year of Buzzard on stream and new production expected from Ettrick and Long Lake, we expect 2008 net production to average between 220,000 and 240,000 boe/d (260,000 and 280,000 before royalties).

Net income in 2007 includes impairment expense of \$366 million (before tax) related to four properties in the Gulf of Mexico as required by successful efforts accounting for oil and gas. The majority of the expense relates to the Aspen deep-water field where recent unsuccessful development drilling and steep production declines resulted in negative reserve revisions. Unsuccessful recompletions, production declines and disappointing development results on the shelf reduced reserves and generated the remainder of the impairment expense.

We invested almost half of our 2007 capital on major development projects at Long Lake and Ettrick. In the Athabasca oil sands, we invested \$1.1 billion in Long Lake Phase 1 and future phases. We are currently injecting steam into the reservoir through all well pads and the SAGD facilities are operating as expected. Upgrader construction is 97% complete and commissioning is progressing well. The upgrader is expected to come on stream mid 2008. In the North Sea, we brought additional development wells on stream at Buzzard and made significant progress on Ettrick. We also invested \$130 million in building our prospect inventory in the US Gulf of Mexico deepwater and Canadian shale gas.

**Cash Flow from Operating Activities**

(Cdn\$ millions)

2007	2,830
2006	2,374
2005	2,143

**Net Income**

(Cdn\$ millions)

2007	1,086
2006	601
2005	1,140

Our 2007 exploration program was focused primarily in the Gulf of Mexico and the North Sea. We were successful with discoveries in the Gulf at Vicksburg and on the shelf, and at Selkirk and Kildare in the North Sea. We also successfully appraised prior discoveries at Longhorn in the Gulf of Mexico and Golden Eagle in the North Sea. Unfortunately, we did not advance our Knotty Head discovery in the Gulf as a suitable drilling rig was not available.

With the weaker US dollar, our net debt decreased over \$300 million from last year. Our US-dollar denominated debt was lower by \$800 million when translated to Canadian dollars. This was partially offset by capital investment that exceeded our cash flow from operations.

Throughout 2007, the US dollar continued to weaken relative to the Canadian dollar. Our sales revenue is denominated in, or referenced to, US dollars and, as a result, our reported Canadian dollar revenues are lower as the US dollar weakens. On the other hand, our US-dollar capital spending and operating costs are also lower when translated to Canadian dollars, as well as our US denominated debt. Overall, the weaker US dollar reduced our 2007 cash flow from operating activities by \$255 million and net income by \$122 million.

During 2007, our proved oil and gas and Syncrude reserves additions replaced 109% of our oil and gas and Syncrude production (108% after royalties) as shown below:

(mmbobe)	Before Royalties	After Royalties
<b>Production</b>		
Oil and Gas	85	68
Syncrude	8	7
<b>Total</b>	<b>93</b>	<b>75</b>
<b>Reserve Changes excluding Production</b>		
Oil and Gas	94	81
Syncrude	8	–
<b>Total</b>	<b>102</b>	<b>81</b>

Two-thirds of our additions relate to our key projects at Buzzard in the North Sea and Long Lake in the Athabasca oil sands. Other additions came from successful exploration and development activities in virtually all areas of our operations, somewhat offset by lower production performance and unsuccessful activities at Aspen and the shelf in the Gulf of Mexico. We also added 10 mmbobe (8 after royalties), net of dispositions, from acquisitions and swaps primarily in the Gulf of Mexico.

## CAPITAL INVESTMENT

(Cdn\$ millions)	Estimated 2008	2007	2006
Major Development	700	1,479	1,849
Early Stage Development	400	162	123
New Growth Exploration	600	573	491
Core Asset Development	600	1,069	748
Total Oil & Gas and Syncrude	2,300	3,283	3,211
Marketing, Corporate, Chemicals and Other	100	118	197
<b>Total Capital</b>	<b>2,400</b>	<b>3,401</b>	<b>3,408</b>

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

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

As conventional basins in North America mature, we have been transitioning toward less mature basins and unconventional resources. Key focus areas include the North Sea, Athabasca oil sands, Canadian CBM and shale gas, Gulf of Mexico deep

waters, offshore West Africa and the Middle East—areas we believe have attractive fiscal terms, significant remaining opportunity, and where we have a competitive advantage.

In 2007, we invested \$3.4 billion in capital expenditures, mostly in major development projects and long cycle-time exploration. In 2008, we plan to invest \$2.4 billion, which is \$1 billion lower than 2007 as we incurred most of the capital costs for the first phase of Long Lake. About half of the 2008 capital investment will be focused on major and early stage development projects, 29% on core assets to sustain production and provide cash flow, and the remainder to drill high-impact exploration wells and continue building our acreage.

**2007 Capital**

(Cdn\$ millions)	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas					
Synthetic (mainly Long Lake)	1,025	108	6	–	1,139
United States	28	2	275	488	793
United Kingdom	323	–	119	274	716
Canada	103	21	117	125	366
Yemen	–	–	12	124	136
Other Countries	–	31	44	22	97
Syncrude	–	–	–	36	36
	1,479	162	573	1,069	3,283
Marketing, Corporate and Other	–	–	–	118	118
<b>Total Capital</b>	<b>1,479</b>	<b>162</b>	<b>573</b>	<b>1,187</b>	<b>3,401</b>
As a % of Total Capital	43%	5%	17%	35%	100%

**2008 Estimated Capital**

(Cdn\$ millions)	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas					
Synthetic (mainly Long Lake)	400	150	–	–	550
United States	80	–	225	85	390
United Kingdom	200	20	210	325	755
Canada	20	50	70	80	220
Yemen	–	–	–	65	65
Other Countries	–	180	95	–	275
Syncrude	–	–	–	45	45
	700	400	600	600	2,300
Marketing, Corporate and Other	–	–	–	100	100
<b>Total Capital</b>	<b>700</b>	<b>400</b>	<b>600</b>	<b>700</b>	<b>2,400</b>
As a % of Total Capital	29%	17%	25%	29%	100%

### Synthetic

In 2007, we invested a total of \$1.1 billion to develop our insitu oil sands resource. This included approximately \$1 billion on the first phase of Long Lake, \$591 million of which related to the upgrader.

Long Lake continues to progress well towards first production of premium synthetic crude in mid 2008. We are currently injecting steam into the reservoir through all well pads. We have started converting wells to SAGD operation and we have also recently started up our first cogeneration unit which allows us to produce electricity and build our steaming capacity. The second cogeneration unit is expected to start up towards the end of the first quarter. We expect bitumen production to ramp up in the spring and we are on track to have sufficient bitumen production for the start up of the upgrader. The bitumen production capacity of the SAGD facilities is approximately 72,000 bbls/d (36,000 bbls/d net to us).

**In 2007, we invested a total of \$1.1 billion to develop our insitu oil sands resource.**

At the end of 2007, construction of the upgrader was 97% complete and commissioning is progressing well. We have turned over the hydrocracker, the OrCrude™ unit and all main plant utilities to operations. The gasifier and air separation unit were essentially mechanically complete at year end 2007, and we are completing final electrical and insulation work. Construction of the sulphur recovery unit is expected to be completed by the end of the first quarter, in sufficient time for first production of synthetic crude oil in mid 2008. Production of premium synthetic crude will ramp up to full rates over a 12 to 18 month period following initial upgrader start up. The upgrader is designed to produce approximately 60,000 bbls/d (30,000 bbls/d net to us) of premium synthetic crude.

The total cost estimate for the Project remains unchanged at between \$5.8 billion and \$6.1 billion (between \$2.9 billion and \$3.05 billion net). We are planning to increase synthetic crude oil production as we sequentially develop our lands with additional 60,000 bbls/d (30,000 bbls/d net) phases using the same technology and design as Long Lake.

### United States

At Longhorn, where we have a 25% working interest, we completed drilling an appraisal well which exceeded our expectations and encountered hydrocarbons in multiple sands. The Longhorn project has been sanctioned and development will consist of subsea tie-backs to a host facility with first production expected in 2009.

In late 2007, we invested \$104 million to acquire three producing deep-water properties at Garden Banks Block 205 and Green Canyon Blocks 137 and 6/50. These properties are currently producing approximately 3,000 boe/d. Drilling of a development well at Green Canyon 6/50 is underway and we expect production from this well to add up to 5,000 boe/d to our 2008 annual volumes.

At Knotty Head, we continue to pursue rig availability in the short term to allow us to spud an appraisal well. To date, we have evaluated two rigs but determined that these rigs did not have the drilling capability required. We have contracted two new deep-water drilling rigs that are scheduled to arrive in mid 2009 and 2010, respectively.

Our 2007 exploration program resulted in discoveries at Vicksburg, Mississippi Canyon 72 and South Marsh Island 257. The Vicksburg discovery well, located on De Soto Canyon Block 353 in the Eastern Gulf of Mexico, was drilled to a depth of approximately 25,400 feet and encountered hydrocarbons. Core was recovered from the well and studies are underway to assess the potential productivity. Additional drilling in the area is planned in 2008. We have a 25% non-operated working interest in this discovery. Shell is the operator with a 57.5% working interest and Plains Exploration & Production Company holds the remaining 17.5% interest. In the same area, we participated in a discovery well in 2003 at Shiloh located on DeSoto Canyon Block 269, that was drilled by Shell. This well was drilled to a total depth of approximately 24,000 feet, encountered hydrocarbons and was temporarily abandoned pending further evaluation of the area. We have a 20% non-operated working interest in Shiloh.

In the Eastern Gulf of Mexico, where the discoveries at Shiloh and Vicksburg are located, we have identified a number of additional exploration opportunities in the region. We also have the right to extend our acreage position through the

acquisition of working interests in various blocks recently awarded to Shell as a result of their participation in Lease Sale 205 late last year.

Our other discoveries at Mississippi Canyon 72 and South Marsh Island 257 are currently being evaluated. Both discoveries are expected to come on production in 2008. We have working interests of 33% and 34.5% respectively in these discoveries.

### United Kingdom

In the UK, we invested over \$700 million in 2007. This included \$160 million at Buzzard where we drilled six development wells. Our Ettrick development in the North Sea is progressing well towards first oil mid 2008. In 2007, we invested approximately \$260 million. This development will utilize a leased floating production, storage and off-loading vessel (FPSO) designed to handle 30,000 bbls/d of oil and 35 mmcf/d of gas. We expect to ramp up to production of approximately 30,000 boe/d gross by the end of the year. We operate Ettrick with an 80% working interest. We have also identified a number of exploration opportunities in the immediate area that could be future tie-backs to Ettrick. We have plans to drill at least two of these opportunities this year.

Elsewhere, we are assessing development alternatives for our Golden Eagle discovery where we have a 34% operated working interest. At Kildare, we are planning to drill an appraisal well this year. The discovery well was drilled to a depth of approximately 14,100 feet. We also completed an appraisal well at Selkirk which confirmed commercial quantities of hydrocarbons and we are currently reviewing development options. We have a 38% operated working interest here.

At Bugle, we are currently drilling an appraisal well. Well results are still being analyzed but initial test results are encouraging. We have a 41% working interest here.

### Canada

In Canada, we are developing the first commercial coalbed methane (CBM) project in the Mannville coals. In 2007, we invested \$173 million in exploration and development activities on our CBM lands.

In northeast British Columbia we have a material land position of approximately 190 net sections in an emerging Devonian shale gas play which has the potential to be one of the most significant shale gas plays in Canada. We are currently evaluating this opportunity with a program of drilling, completing and production testing.

### Yemen

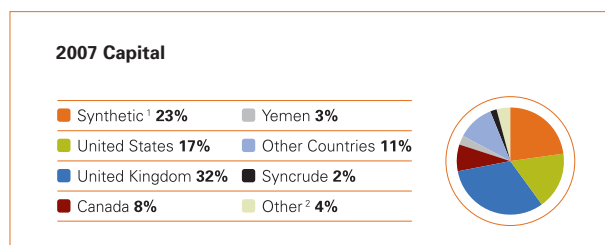
Yemen remains a significant asset for us and is expected to generate approximately 15% of our projected cash flow in 2008. In 2007, we invested \$136 million and in 2008, we expect to produce between 50,000 and 55,000 boe/d before royalties here.

### Other Countries

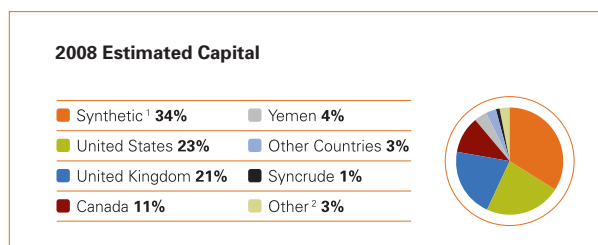
The Usan field development, located in Nigeria on offshore Block OPL -222, continues to move forward. We expect the project to advance to the execution phase shortly and this will facilitate the award of the major deep-water facilities contracts. The project will have the ability to process an average of 180,000 bbls/d of oil during the initial production plateau period through a new FPSO with a two million barrel storage capacity. We have a 20% interest in exploration and development on this block.

### Syncrude

At Syncrude, we invested \$36 million in 2007. In 2008, we have turnarounds scheduled in the second and third quarters and expect annual production of between 20,000 and 25,000 bbls/d.



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



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

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

(Cdn\$ millions)

	2007 vs 2006	2006 vs 2005
<b>Net Income for 2006 and 2005 <sup>1</sup></b>	<b>601</b>	<b>1,140</b>
Favourable (unfavourable) variances: <sup>2</sup>		
Production Volumes, After Royalties		
Crude Oil	1,354	(245)
Natural Gas	(17)	(55)
Change in Crude Oil Inventory	22	(74)
Total Volume Variance	1,359	(374)
Realized Commodity Prices in Canadian Dollars		
Crude Oil	308	325
Natural Gas	(24)	(133)
Total Price Variance	284	192
Operating Expense		
Conventional Oil & Gas	(178)	13
Syncrude	(21)	(35)
Total Operating Expense Variance	(199)	(22)
Depreciation, Depletion, Amortization and Impairment		
Oil & Gas and Syncrude	(636)	(48)
Other	(7)	4
Total Depreciation, Depletion, Amortization and Impairment Variance	(643)	(44)
Exploration Expense	36	(111)
Energy Marketing Contribution	(373)	336
Chemicals Contribution	27	(12)
General and Administrative Expense	181	254
Interest Expense	(115)	44
Current Income Taxes	(66)	(29)
Future Income Taxes	(43)	(549)
Other		
Block 51 Settlement	151	(151)
Business Interruption Insurance Proceeds	(154)	152
Gains from Divestiture Programs	–	(418)
Increase (Decrease) in Fair Value of Crude Oil Put Options	(32)	185
Other	72	8
<b>Net Income for 2007 and 2006</b>	<b>1,086</b>	<b>601</b>

Notes:

1 2005 includes results of discontinued operations (see Note 14 to our Consolidated Financial Statements).

2 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**

	2007		2006		2005	
	Before Royalties <sup>1</sup>	After Royalties	Before Royalties <sup>1</sup>	After Royalties	Before Royalties <sup>1</sup>	After Royalties
<b>Oil and Liquids</b> (mmbbls/d)						
United Kingdom	81.2	81.2	16.9	16.9	12.6	12.6
Yemen	71.6	39.8	92.9	51.8	112.7	60.6
Canada <sup>2</sup>	17.1	13.4	20.0	15.8	29.2	22.6
United States	16.4	14.5	17.0	15.0	22.2	19.6
Other Countries	6.2	5.7	6.3	5.7	5.6	5.1
Syncrude (mmbbls/d) <sup>3</sup>	22.1	18.8	18.7	16.9	15.5	15.3
	214.6	173.4	171.8	122.1	197.8	135.8
<b>Natural Gas</b> (mmcf/d)						
United Kingdom	16	16	20	20	23	23
Canada <sup>2</sup>	118	98	108	91	124	101
United States	101	86	111	94	116	99
	235	200	239	205	263	223
<b>Total</b> (mboe/d)	<b>254</b>	<b>207</b>	<b>212</b>	<b>156</b>	<b>242</b>	<b>173</b>

Notes:

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

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

	2007	2006	2005
<i>Before Royalties</i>			
Oil and Liquids (mmbbls/d)	–	–	6.7
Natural Gas (mmcf/d)	–	–	24
<i>After Royalties</i>			
Oil and Liquids (mmbbls/d)	–	–	5.3
Natural Gas (mmcf/d)	–	–	17

3 Considered a mining operation for US reporting purposes.

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

Production before royalties increased 20% from 2006, 33% after royalties. This increase reflects the start up of Buzzard in early 2007, offset by declines in our maturing Yemen fields.

The following table summarizes our production changes year over year:

(mboe/d)	Before Royalties	After Royalties
2006 Production	212	156
Production Changes		
United Kingdom	64	64
Yemen	(21)	(12)
Syncrude	3	2
Other	(4)	(3)
<b>2007 Production</b>	<b>254</b>	<b>207</b>

In 2008, we expect additional production growth over 2007 and expect production to range from 220,000 to 240,000 boe/d (260,000 and 280,000 boe/d before royalties). Increases are expected from a full year of Buzzard, and from the mid-year start up of Long Lake Phase 1 and the North Sea Etrick development.

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

**United Kingdom**

The addition of high-margin, royalty-free Buzzard volumes increased North Sea production by 64,000 boe/d (net to us), up 300% from last year. Buzzard came on stream January 7, 2007 and ramped up to peak production during the year. While the ramp-up was slower due to pipeline restrictions and the reliability of the acid gas removal system, we regularly exceeded initial expectations. Buzzard has safely produced as high as 220,000 boe/d (95,000 net to us), higher than originally expected. We are proceeding with work to add additional sweetening facilities to handle higher levels of hydrogen sulphide, and are reviewing debottlenecking opportunities to increase the processing capacity of the platform. We had ten wells on stream at Buzzard at the end of 2007.

**Buzzard came on stream in January 2007 and has safely produced as high as 220,000 boe/d (95,000 net to us), 10% above expectations.**

Scott/Telford produced 16,500 boe/d, comparable with 2006 rates. During the second quarter of 2007, we increased our interests in the Scott and Telford fields by 0.9% and 17.4%, respectively. The additional production we purchased was offset by natural declines and downtime caused by increased maintenance activity. Farragon produced 2,600 boe/d during the year, 30% lower than 2006 as a result of natural declines. In the fourth quarter, production from our non-operated Duart field came on stream.

In 2008, we plan to drill additional development wells at Buzzard and Scott/Telford and we anticipate bringing production on stream at Ettrick mid year. We expect production from the North Sea to average between 95,000 and 115,000 boe/d in 2008. Our expected production for 2008 reflects some provision for planned and unplanned downtime.

**Yemen**

Yemen production declined 23% from 2006. Masila production decreased 19%, consistent with expectations. In 2007, we

drilled 18 development wells and 12 sidetrack wells. Strong initial rates from new wells, combined with well optimizations and reservoir management, helped to minimize expected production declines. Base declines at Masila are expected to continue as most of the development opportunities were previously drilled to maximize reserve and capital recoveries under the production sharing agreement. We continue to concentrate capital on maximizing recoveries, and therefore economic returns, from our existing wells before our contract expires in 2011. In 2008, we plan to drill 10 development wells and continue to optimize well performance.

On Block 51 in Yemen, production from the East Al Hajr field declined 35% as a result of natural declines and fewer development wells. We drilled 13 development wells in 2007 as compared to 24 the year before. Five development wells are planned for 2008.

Substantial value still remains in our Yemen assets as we expect to generate approximately 22% of the total project free cash flow from Masila over the remaining life of the contract. We expect our share of Yemen production to average between 50,000 and 55,000 boe/d in 2008.

**Canada**

Production in Canada decreased 3% from the previous year. CBM production rates continue to increase as our wells in the Fort Assiniboine area de-water and we bring additional development wells and facilities on stream. We are optimizing the operation of the CBM development wells to maximize up-time and efficiency. Declines in our natural gas properties in the Medicine Hat region have been more than offset by infill drilling, and future opportunities remain in the region for additional infill drilling. Our capital investment in heavy oil properties continues to partially offset natural declines. At our Balzac gas facility, north of Calgary, we completed a turnaround mid year, which required production to be shut-in for approximately 48 days.

In 2008, we expect production from Canada to average between 45,000 and 50,000 boe/d, with new premium synthetic crude oil at Long Lake expected mid year and higher CBM volumes.

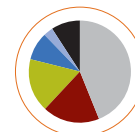
**2007 Production before Royalties**

Yemen 28%	United Kingdom 33%
Canada 15%	Other Countries 2%
United States 13%	Syncrude 9%



**2006 Production before Royalties**

Yemen 44%	United Kingdom 9%
Canada 18%	Other Countries 3%
United States 17%	Syncrude 9%



### United States

Gulf of Mexico production decreased 6%, or about 2,300 boe/d from 2006. At Aspen, production increased 1,500 boe/d from the previous year. Natural declines in the field, and maintenance and weather-related shut-ins of the non-operated processing facilities partially offset production from new development wells. In late 2006, we brought the Aspen 5 development well on stream; however, decline rates in this well were higher than expected. We previously identified other opportunities at Aspen and completed a sidetrack mid year to exploit deeper sands. While we were encouraged by well log data indicating thick pay zones in the sidetrack, well deliverability rates could not be sustained. This likely indicates barriers within this section of the reservoir that are not present elsewhere. The other Aspen wells continue to produce in line with expectations; however, we expect field production to continue declining as a result of increasing water cuts and reservoir depletion.

Gunnison production was approximately 3,800 boe/d or 36% lower than last year due to natural declines and mechanical issues in one high volume well. Gunnison accounted for 20% of our production from the Gulf of Mexico during the year and we expect to bring another development well on stream in 2008. The Wrigley development came on stream early July but gas production was restricted by limited heat exchanger capability on the non-operated processing facility resulting in an annualized average production rate of 7 mmcf/d in 2007. We are currently working with the facility operator and expect production to increase to peak rates of 24 mmcf/d (net to us) in 2008. Late in the third quarter, we acquired three deep-water properties producing approximately 3,000 boe/d. We expect to drill an additional development well at one of these properties in early 2008.

On the shelf, our mature assets continue to be impacted by natural declines, and limited workover and recompletion activity. Declines at Vermilion 76, Eugene Island 18 and West Cameron 170 were only partially offset by Vermilion 340 production that was restored in early 2007. Vermilion 340 was shut-in since 2005 due to damage to the sub-surface pipeline system caused by hurricanes in 2005. Our shelf production declined 13% from 2006.

In 2008, we expect total production from the Gulf of Mexico to average between 25,000 and 30,000 boe/d.

### Other Countries

Production from Guando in Colombia was consistent with 2006. We sustained production rates by maintaining reservoir pressure through an active waterflood program and by drilling additional infill wells. We expect to maintain current production rates in 2008; however, our interest in the field will decrease to 10% once the field has produced 60 million barrels, likely in 2009.

### Syncrude

At Syncrude, production averaged 22,060 boe/d, up 18% from 2006 as the Stage 3 expansion contributed a full year of production. Despite this increase, production was lower than expected as Coker 8-3 had a utilization rate of less than 70% over the year because of a variety of operating issues with the new equipment. After an extended turnaround on the LC Finer and Coker 8-3 in the second quarter of 2007, the Coker processed bitumen at expected capacity until early October when it was temporarily shut in due to coke build up. In December, production was partially reduced for four days due to a fire in Coker 8-3's environmental precipitators. In early 2008, production at Syncrude was temporarily suspended for six days due to an upset in the amine and fuel gas system that was brought on by extremely cold weather conditions.

Strong realized prices for our production have enabled us to fully recover capital costs at Syncrude including costs associated with the Stage 3 expansion. Consequently, our Syncrude royalties increased from a 1% gross revenue royalty to a 25% net revenue royalty, beginning in 2006. This translates into lower after royalty production relative to our working interest production volumes. The Alberta government is currently negotiating with the Syncrude owners to amend the existing royalty agreement, which is in place until 2016. This could result in Syncrude moving to the proposed royalty framework, which features higher royalty rates, before January 2016 in exchange for other concessions.

In 2008, we expect our share of Syncrude production to average between 20,000 and 25,000 bbls/d.

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

Production before royalties decreased 12% from 2005, 10% after royalties. Our 2006 production excluded 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 decreased 8% and 5%, respectively. Decreases were caused by natural declines at mature fields in Yemen and at Aspen in the Gulf of Mexico.

## Commodity Prices

	2007	2006	2005
<b>Crude Oil</b>			
West Texas Intermediate (WTI) (US\$/bbl)	72.31	66.22	56.58
Benchmark Differentials <sup>1</sup> (US\$/bbl)			
Heavy Oil	23.44	21.79	20.82
Mars	5.67	7.34	6.59
Masila	0.50	3.00	5.71
Dated Brent	(0.21)	1.08	2.20
Producing Assets (Cdn\$/bbl)			
Yemen	76.29	71.57	62.07
Canada	44.07	42.79	40.51
United States	69.83	65.80	57.63
United Kingdom	76.30	71.19	60.55
Other Countries	71.29	66.09	59.96
Syncrude	79.76	72.32	71.00
Corporate Average (Cdn\$/bbl)	73.43	67.50	58.98
<b>Natural Gas</b>			
New York Mercantile Exchange (US\$/mmbtu)	7.12	6.99	8.99
AECO (Cdn\$/mcf)	6.26	6.62	8.04
Producing Assets (Cdn\$/mcf)			
Canada	6.32	6.49	7.51
United States	7.80	7.86	10.56
United Kingdom	4.71	7.43	7.86
Corporate Average (Cdn\$/mcf)	6.81	7.18	8.89
<b>Nexen's Average Realized Oil and Gas Price</b> (Cdn\$/boe)	<b>68.46</b>	<b>62.92</b>	<b>57.97</b>
Average Foreign Exchange Rate—Canadian to US Dollar	0.9304	0.8818	0.8253

Note:

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

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

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

### Crude Oil Reference Prices

Crude oil prices remained strong in 2007. Crude oil prices climbed steadily throughout the year, with WTI ranging from

a low of US\$49.90/bbl early in the year to US\$95.98/bbl in December. In early 2008, WTI broke through US\$100/bbl in intra-day trading but has since slipped to about US\$90/bbl on fears of a US recession. The main drivers of the high prices last year were concerns over supply resulting from geopolitical tensions around the world, strong global demand, declining inventory levels and a weakening US dollar.

Geopolitical risk continued to be an underlying theme throughout 2007. In the Middle East, on-going tensions between the US and Iran over its uranium enrichment program led to fears that it would escalate to potential US action against Iran and a reduction in oil exports. Conflict also escalated between Turkey and Kurdish rebels in Northern Iraq, where a substantial portion of the country's oil production is located. Supply outages in Nigeria caused by continued violence, and nationalization of Venezuela's energy industry also contributed to higher prices and market volatility.

Global demand growth for crude oil continues to be robust. Demand from China, the world's second largest oil consumer, India, Russia and the Middle East grew from last year whereas global supply increased marginally. There are concerns over supply from politically unstable locations such as Nigeria, Iran and Iraq, some of the world's major oil producers and exporters. A sustained decline in inventories also contributed to strong oil prices. Crude oil inventories at the end of 2007 were at their lowest levels in the last five years.

A steadily weakening US dollar helped fuel the rise of crude oil prices to an all-time nominal high since global crude oil is denominated in US dollars. Weak equity markets also re-directed investment into the financial commodity markets, increasing volatility.

**Crude Oil Differentials**

In Canada, heavy crude oil differentials averaged US\$23.44/bbl (32% of WTI) for the year, compared to US\$21.79/bbl (33% of WTI) in 2006. Differentials were narrower than usual at the beginning of the year as OPEC cuts from late 2006 tended to be heavy oil, thereby increasing prices for heavier crude. As we headed into the summer asphalt season, we expected a seasonal narrowing. However, a major fire at BP's Whiting refinery in March curtailed its ability to process heavy oil for the remainder of the year reducing the demand for Canadian heavy crude by 100,000 barrels a day. Late in the year, the differentials widened substantially due to pipeline constraints until a shutdown at the Albion upgrader in the Athabasca oil sands freed up pipeline space. In December, the heavy oil differential improved from \$45/bbl to \$25/bbl as a result of weaker WTI prices and the Albion upgrader incident. Heavy oil prices are expected to weaken again in January and February once the Albion upgrader is back on stream.

The Brent/WTI differential strengthened during 2007 with Brent trading at a premium of US\$0.21/bbl compared to a discount of US\$1.08/bbl in 2006. The Brent index is relevant for us as approximately 80% of our current crude production is priced based on Brent. WTI traded at a discount to Brent for

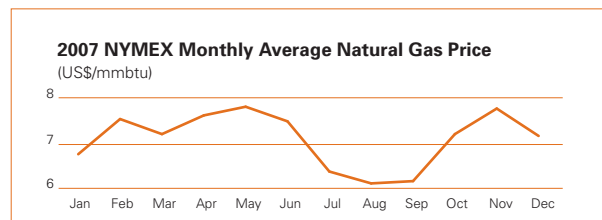
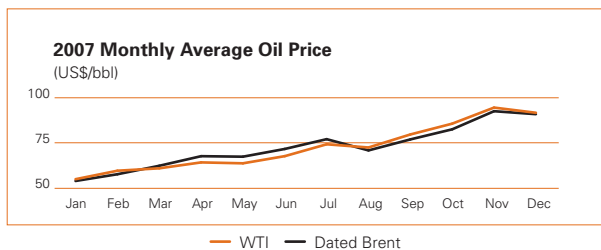
almost half of the year. Regional issues, such as an overabundance of crude in local storage around the Cushing, Oklahoma area where WTI is priced and the limited ability to move that crude to world markets caused WTI to trade at lower prices than other international grades of crude oil. By comparison, Brent prices were strong as multiple transportation options allow it to remain a global crude oil. However, WTI regained its strength and traded at a premium to Brent during the latter part of the year.

The US Gulf Coast Mars differential narrowed, averaging US\$5.67/bbl in 2007 compared to US\$7.34/bbl in 2006. Since Mars can be moved globally, it competes with international crudes and was not readily affected by the pipeline constraints at Cushing earlier in the year which depressed WTI.

The Yemen Masila differential narrowed substantially relative to WTI during 2007, averaging US\$0.50/bbl compared to US\$3.00/bbl last year. Yemen Masila traded at a premium to WTI in the summer, reflecting the impact of stronger Brent pricing since Masila crude is priced off Brent. As WTI regained its strength relative to Brent in the fall, the Yemen Masila differential traded at a discount to WTI for the remainder of the year.

**Natural Gas Reference Prices**

NYMEX natural gas prices averaged US\$7.12/mmbtu, compared to US\$6.99/mmbtu in 2006. In January 2007, gas prices were unusually soft at the peak of the withdrawal season as January experienced the highest global temperature on record for this time of year. However, natural gas prices rebounded in the following months as a result of strong crude oil prices, technical trading in financial markets and cold weather in several key North American natural gas consuming regions. Natural gas prices weakened during the summer and autumn seasons reflecting higher storage levels that were approaching the top of the North American five-year average. The high storage levels were caused by LNG cargoes being diverted to North America from weak European markets, mild summer weather and a quiet hurricane season in the Gulf of Mexico.



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

Crude oil prices remained strong for most of 2006, with WTI finishing the year at US\$61.05/bbl, roughly where it began. 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.

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, mild January temperatures experienced in

several key North American natural gas consuming regions resulted in a weaker 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.

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.

**Operating Expenses**

	2007		2006		2005	
	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	6.56	12.00	4.45	8.11	3.63	6.75
Canada	12.91	15.93	10.31	12.73	8.21	10.34
United States	8.43	9.69	8.17	9.45	6.35	7.33
United Kingdom	6.94	6.94	11.28	11.28	14.90	14.90
Other Countries	3.45	3.76	2.87	3.13	5.55	6.08
Average Conventional	7.89	9.75	6.95	9.69	6.03	8.70
<b>Synthetic Crude Oil</b>						
Syncrude	25.80	30.32	27.53	30.43	26.95	27.22
<b>Average Oil and Gas</b>	9.45	11.63	8.77	11.96	7.36	10.34

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.

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

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

At Masila in Yemen, operating costs increased with higher service rig activity and maintenance programs. These costs are necessary to minimize production declines and maximize the recovery of the remaining reserves, given the maturity of the field. The higher costs and lower production increased our corporate average by \$0.57/boe. Similarly at Block 51, our operating expenditures were higher as additional service rig activity and higher water handling, fuel and equipment costs increased operating expenditures. The higher costs increased our corporate average \$0.37/boe. We expect the average per-unit cost to continue to increase in Yemen as production declines.

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

In the Gulf of Mexico, while total operating costs remained consistent year over year, lower production increased our corporate average by \$0.18/boe. During 2007, industry pressures increased costs and we performed additional downhole and surface maintenance activity to maintain production. However, these costs had minimal impact on our corporate average when compared to last year as our 2006 costs included extended maintenance and turnaround activity at Eugene Island on the shelf.

**Operating costs at Buzzard are low, reducing our corporate average by \$1.58/boe.**

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

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

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

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

In Yemen, operating costs on a per-unit basis increased as fixed costs from our central processing facilities and increased water handling costs were spread over lower production volumes. Masila increased our corporate average by \$0.20/boe, reflecting lower production, increased service rig activity to minimize production declines, and costs to replace a single point mooring system to load oil tankers. 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.

Following the sale of Canadian conventional oil and gas properties in 2005, we had proportionately more heavy oil production, which had higher operating costs than the lighter oil production we sold. Canadian operating costs in 2006 increased our corporate average by \$0.18/boe. Operating costs in the Gulf of Mexico increased from 2005 due to industry cost pressures caused by strong commodity prices and the 2005 hurricane season. Lower production volumes and workovers on our shelf properties early in 2006 increased our corporate average by \$0.39/boe.

With the sale of Canadian production in 2005, barrels from the North Sea contributed a higher percentage of our total production. As the North Sea had higher operating costs than our average cost per barrel, the change in production mix increased our corporate average by \$0.32/boe. This was offset by lower operating costs relative to 2005, as operating expenses in 2005 included repair costs related to turbine failures. This reduced our corporate average by \$0.26/boe.

Syncrude increased our corporate average operating costs by \$0.72/boe from 2005 as a result of maintenance activities and the coker turnaround 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 as compared to 2005 by \$0.38/boe.

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

(Cdn\$/boe)	2007		2006		2005	
	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	8.15	14.92	9.67	17.61	8.56	15.93
Canada	12.46	15.37	11.22	13.84	9.26	11.67
United States <sup>2</sup>	22.64	26.03	16.28	18.84	15.39	17.77
United Kingdom	19.59	19.59	30.22	30.22	33.25	33.25
Other Countries	3.68	4.06	4.30	4.69	6.20	6.79
Average Conventional	14.94	18.47	13.12	18.30	11.78	17.00
<b>Synthetic Crude Oil</b>						
Syncrude	6.59	7.74	4.81	5.32	3.08	3.12
<b>Average Oil and Gas</b>	14.21	17.49	12.38	16.88	11.23	15.77

## Notes:

- 1 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.
- 2 DD&A per boe excludes the impairment charges described in Note 6 of our Consolidated Financial Statements.

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

In 2007, our DD&A expense includes \$366 million (\$3.96/boe) of impairment expense primarily related to our Aspen, Vermillion 320/340 and West Cameron 170 properties in the Gulf of Mexico as we had poor results from capital investments and lower reserve estimates. At Aspen, disappointing results from our recent investment in development drilling resulted in negative reserve revisions. While we were encouraged by well log data indicating thick pay zones, well deliverability rates could not be sustained. This likely indicates barriers within this section of the reservoir. At Vermillion 320/340 and West Cameron 170, negative reserve revisions primarily relate to gas properties, where unsatisfactory investment results, production performance, revised mapping and higher projected operating costs resulted in a downward revision to reserves estimates. The carrying values of these properties were reduced to their estimated fair value.

Production from Buzzard increased our corporate average unit DD&A rate by \$1.44/boe. Buzzard costs are higher than our corporate average as they include acquisition and project completion costs. We expect Buzzard unit depletion to decrease over time as we expect to book more proved reserves from production experience and further development drilling. We recognized additional proved reserves at

the end of 2006 for our other UK assets, which lowered the corporate average \$0.59/boe in 2007.

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

Depletion of our Canadian assets increased our corporate average by \$0.24/boe reflecting the timing of reserve bookings from our CBM projects in central Alberta, and land acquisitions in 2006. As our new CBM wells progress through the de-watering stage and production increases, we expect to recognize additional proved reserves which will reduce our unit depletion rate.

In the Gulf of Mexico, unsuccessful development drilling at Aspen and on the shelf increased our capital base, increasing our corporate average rate by \$1.29/boe.

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

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

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

Our 2006 DD&A expense included \$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 were reduced to their estimated fair value. In addition, our 2006 DD&A expense included \$15 million (2005—\$58 million) relating to a partial write down 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 was \$12.38/boe, up 10% from 2005.

In Yemen, we began depleting the permanent production facilities on Block 51 in 2006 following their commissioning earlier in the year. Strong crude oil prices allowed us to continue to maximize recovery of costs we paid on the government's behalf. This increased our corporate average by \$0.64/boe.

Our increased Canadian depletion rate reflected depletion of costs for our CBM projects in central Alberta, which increased our corporate average by \$0.35/boe. 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 was higher than our average, primarily from the purchase price allocation assigned to them when acquired in 2004. Our corporate average is increasing as the North Sea becomes a larger proportion of our total production and Canada becomes a small portion, following the sale of Canadian conventional oil and gas assets in 2005. This change increased our corporate average by \$0.42/boe.

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 corporate DD&A by \$0.72/boe from 2005 as the depletion of our international and US assets is denominated in US dollars.

### Exploration Expense <sup>1</sup>

(Cdn\$ millions)	2007	2006	2005
Seismic	123	128	53
Unsuccessful Drilling	126	169	143
Other	77	65	55
<b>Total Exploration Expense</b>	<b>326</b>	<b>362</b>	<b>251</b>
New Growth Exploration	573	491	456
Geological and Geophysical Costs	123	128	53
<b>Total Exploration Expenditures</b>	<b>696</b>	<b>619</b>	<b>509</b>
Exploration Expense as a % of Exploration Expenditures	47%	58%	49%

Note:

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

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

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

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

In the deep-water Gulf of Mexico, we drilled a successful appraisal well at Longhorn and evaluated resource estimates. The Longhorn development has been sanctioned and production is expected in 2009. Also in the deep water, our Vicksburg prospect was drilled to a depth of 25,400 feet and encountered hydrocarbons. Core was recovered from the well and studies are underway to assess the potential productivity. Additional drilling in the area is planned in 2008. Our unsuccessful drilling results in the Gulf of Mexico were primarily on the shelf where we expensed \$35 million for dry holes. In the deep water, we drilled a sidetrack at Aspen targeting two zones in deeper sands; however, results from the lowest zone were unsuccessful and we expensed \$20 million for a portion of the drilling costs of the well.

**In the deep-water Gulf of Mexico, we drilled a successful appraisal well at Longhorn. Development has been sanctioned and production is expected in 2009.**

In the UK North Sea, we had several exploration successes. We followed up on our successful Golden Eagle well by drilling a sidetrack to appraise the accumulation. We are currently evaluating development options for this discovery. At Selkirk, we successfully completed an appraisal well and sidetrack and are currently assessing development alternatives. At Kildare, we plan to drill an appraisal well in third quarter of 2008. Our 2007 dry hole costs in the UK North Sea were \$39 million compared to \$21 million in 2006. The \$15 million Guinea well was completed in the first quarter; however, the target reservoir was water bearing and the well was abandoned. Further exploration wells at Stag and Dee were plugged and abandoned, resulting in \$12 million and \$8 million, respectively, in expensed costs.

In Colombia, we expensed \$11 million related to the unsuccessful Guaini-1 and Atalea-1 exploratory wells. In Canada, we expensed costs associated with unsuccessful CBM activities at Provost, Kakwa and Sullivan Lake. Seismic data costs of \$123 million were comparable with 2006. The Gulf of Mexico

and Norway accounted for 74% of the seismic expenditures, as we consider these areas to have significant exploration potential. Data has been acquired during the last two years to support our acreage accumulation efforts.

We plan to invest approximately \$600 million in our 2008 exploration and appraisal program and anticipate drilling up to 11 exploration and four appraisal wells in the Gulf of Mexico, North Sea and Yemen.

**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 on acquiring seismic data. We were successful at Great White West and Longhorn (formerly Ringo) in the Gulf of Mexico. In early 2007, we completed drilling at our Golden Eagle prospect in the UK North Sea. The discovery well was drilled to approximately 7,500 feet and encountered hydrocarbons.

Our unsuccessful drilling results were primarily in the Gulf of Mexico, where we expensed \$135 million in dry hole costs. Early in 2006, 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 2006, 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.

Our geological and geophysical costs include \$128 million of seismic data acquired during 2006, half related to the Gulf of Mexico. The balance was spent on acquiring data in Canada, Norway, the North Sea, Nigeria and other international targets.

**OIL & GAS AND SYNCRUDE NETBACKS**

Netbacks are the cash margins, before general and administrative expenses, we receive for every equivalent barrel sold. The following table lists the sales prices, per-unit costs and netbacks for our producing assets, calculated using our working interest production before and after royalties. A combination of strong realized prices and new high-margin production from Buzzard increased our cash netback by 32% from 2006 (17% after royalties).

**Before Royalties**

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

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

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>

**After Royalties**

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

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

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>

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)	2007	2006	2005
Physical Sales <sup>1</sup>	47,826	40,920	37,873
Physical Purchases <sup>1</sup>	(46,897)	(39,925)	(36,988)
Net Financial Transactions <sup>1</sup>	(49)	314	(38)
Increase in Fair Market Value of Inventory	79	–	–
Net Revenue	959	1,309	847
Transportation Expense	(806)	(789)	(641)
Other	14	20	(2)
<b>Net Marketing Revenue</b>	<b>167</b>	<b>540</b>	<b>204</b>
<b>Contribution to Net Marketing Revenue by Region:</b>			
North America	151	526	186
Asia	11	13	18
Europe	5	1	–
<b>Net Marketing Revenue</b>	<b>167</b>	<b>540</b>	<b>204</b>
Depreciation, Depletion, Amortization and Impairment	(13)	(12)	(11)
General and Administrative	(87)	(112)	(89)
<b>Marketing Contribution to Income from Continuing Operations before Income Taxes</b>	<b>67</b>	<b>416</b>	<b>104</b>
<b>North America</b>			
<b>Natural Gas</b>			
Physical Sales Volumes <sup>2</sup> (bcf/d)	5.8	5.4	4.9
Transportation Capacity (bcf/d)	2.0	3.3	4.0
Storage Capacity (bcf)	39	50	30
Financial Volumes (bcf/d)	21.9	19.8	12.1
<b>Crude Oil</b>			
Physical Sales Volumes <sup>2</sup> (mmbbls/d)	655	553	318
Storage Capacity (mmbbls)	2,734	1,749	580
Financial Volumes (mmbbls/d)	2,134	1,976	819
<b>Power</b>			
Physical Sales Volumes <sup>2</sup> (MW/d)	4,516	4,388	2,548
Generation Capacity (MW/hr)	87	87	53
<b>Asia</b>			
Physical Sales Volumes <sup>2</sup> (mmbbls/d)	183	152	192
Financial Volumes (mmbbls/d)	256	207	163
<b>Europe</b>			
Financial Volumes (mmbbls/d)	529	52	–
<b>Value-at-Risk</b>			
Year End	26	26	24
High	38	33	28
Low	24	17	11
Average	30	23	21

Notes:

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

2 Excludes intra-segment transactions.

**2007 vs 2006—Reduced energy marketing contribution decreased net income by \$373 million**

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

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

The contribution of our North American crude oil marketing team was lower than 2006 as their portfolio, both physical and financial, was positioned to take advantage of contango (rising forward month prices) in the crude oil forward curve. Late summer, near-term crude oil prices moved up sharply, moving the forward curve from contango to backwardation (falling forward month prices). As a result, we suffered losses in our financial time spread positions. We continued to capture profits from location and quality spreads by diverting crude oil to more attractive markets or blending to enhance crude quality.

Our power marketing group remains the largest supplier of power to the commercial and industrial sector in Alberta and continued to deliver solid returns.

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

In late 2006, we de-designated certain futures contracts that were designated as cash flow hedges of future sales of our natural gas in storage. These contracts were de-designated since it became uncertain that the future sales would occur within the designated time frame. As it was reasonably possible

that the future sales could have taken place as designated at the inception of the hedging relationship, gains of \$65 million on the futures contracts were deferred in accounts payable at December 31, 2006. These gains were recognized in marketing and other income during the first quarter of 2007.

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

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

Marketing had record results in 2006, with all areas achieving records. The largest contribution came 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 opportunities 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 were consistent with prior years, we executed more transactions and added more capacity, particularly storage, during the year.

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

We continued our expansion into new markets during 2006 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.

### Composition of Net Marketing Revenue

(Cdn\$ millions)	2007	2006	2005
Trading Activities (Physical and Financial)	147	520	195
Non-Trading Activities	20	20	9
<b>Total Net Marketing Revenue</b>	<b>167</b>	<b>540</b>	<b>204</b>

### Trading Activities

In our energy marketing group, we enter into contracts to purchase and sell crude oil and natural gas. We also use financial and derivative contracts, including futures, forwards, swaps and options for hedging and trading purposes. We account for all derivative contracts 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. We do not value any derivative contracts using internal models.

### Fair Value of Derivative Contracts

At December 31, 2007, the fair value of our derivative contracts totalled \$6 million (2006—\$360 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	
Prices					
Actively Quoted Markets	(204)	96	(21)	(8)	(137)
From Other External Sources	125	9	7	2	143
Based on Models and Other Valuation Methods	—	—	—	—	—
<b>Total</b>	<b>(79)</b>	<b>105</b>	<b>(14)</b>	<b>(6)</b>	<b>6</b>

### Changes in Fair Value of Derivative Contracts

(Cdn\$ millions)	Total
<b>Fair Value at December 31, 2006</b>	<b>360</b>
Change in Fair Value of Contracts	(10)
Net Losses (Gains) on Contracts Closed	(344)
Changes in Valuation Techniques and Assumptions <sup>1</sup>	—
<b>Fair Value at December 31, 2007</b>	<b>6</b>

Note:

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

The fair values of our derivative contracts will be realized over time as the contracts settle. Until then, the value of certain contracts will vary with forward commodity prices and price differentials. The average term of our derivative contracts is approximately 1.4 years. Those maturing beyond one year primarily relate to North American natural gas positions.

### Fair Value of Trading Inventories and Capacity Contracts

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 reducing volatility in our economic results. Accounting rules

can 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.

Similar to capacity contracts, we hold commodity inventories for trading purposes that allow us to take advantage of pricing differences between time periods (i.e. summer vs winter). We carry these inventories at fair value as measured by the

one-month forward price, less any costs to sell. We economically hedge the future value of our trading inventories based on our expected holding period, which is generally more than one month. The derivative contracts used to hedge our trading inventories are carried at fair value, which considers the future settlement of the contract, whereas the commodity inventories are valued only one-month forward. The timing difference can create volatility in our reported results.

At the end of 2007, the unrecognized future value of the commodity inventory and capacity contracts was a gain of \$51 million (2006—\$81 million loss). The future commitment for these capacity contracts has been included in our contractual obligations, commitments and guarantees in the MD&A.

## CHEMICALS

(Cdn\$ millions)

	2007	2006	2005
Net Sales	414	407	398
Sales Volumes (thousand short tons)			
Sodium Chlorate	478	487	493
Chlor-alkali	465	451	450
Operating Profit <sup>1,3</sup>	151	124	136
Operating Margin <sup>2,3</sup>	36%	30%	34%
Chemicals Contribution to Income from Continuing Operations Before Income Taxes	64	44	37
Capacity Utilization	94%	95%	96%

Notes:

- 1 Total revenues less operating costs, transportation and other.
- 2 Operating profit divided by net sales.
- 3 Includes foreign exchange gains or losses on debt.

### 2007 vs 2006—Higher chemicals operating profit increased net income by \$27 million

Our investment in the chemicals business is held through our 61.4% interest in the Canexus Limited Partnership. The remaining interest is publicly traded through the Canexus Income Fund. Realized North America chlorate prices were up 5% in 2007 and sales volumes remained strong, despite unplanned maintenance of our facilities and pulp mill shut downs. The full effect of the price increase was partially eroded by the strengthening Canadian dollar which reduced US-dollar denominated sales by \$9 million. Brazilian sales remained strong with continued demand from our main pulp mill customer Aracruz Cellulose.

The expansion at our plant in Brandon, Manitoba is well underway. Completion is expected in 2008 with capacity expected to increase 12%. The Brandon plant benefits from low electricity rates in Manitoba where the electricity market

is based on hydroelectric power and is regulated. We also benefit from the economies of scale we achieve as this is the world's largest sodium chlorate facility.

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

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

While North American prices for sodium chlorate remained strong throughout 2006, sales volumes fell slightly from 2005 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.

**CORPORATE EXPENSES****General and Administrative (G&A)**

(Cdn\$ millions)	2007	2006	2005
General and Administrative Expense before Stock-Based Compensation	336	345	302
Stock-Based Compensation <sup>1</sup>	38	210	507
<b>Total General and Administrative Expense</b>	<b>374</b>	<b>555</b>	<b>809</b>

Note:

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

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

G&A expense dropped 33% from 2006 with lower stock-based compensation expense. Changes in our share price create volatility in our net income as we account for stock-based compensation using the intrinsic-value method. This method uses our share price at the end of the reporting period to determine our stock-based compensation expense and related obligations. At the end of 2007, our stock price closed unchanged from the end of 2006. As a result, most of our 2007 stock-based compensation expense is related to vesting of stock-based compensation plans. Cash payments to employees for stock-based compensation programs increased 24% from 2006 to \$147 million.

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

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

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

In 2006, our share price increased 16%, creating over \$2.3 billion of shareholder value. The stock based compensation expense represented approximately 9% of the increase in shareholder value. Cash payments to employees for our stock-based compensation programs were \$119 million in 2006, up 61% from 2005.

**Interest**

(Cdn\$ millions)	2007	2006	2005
Interest	341	294	275
Less: Capitalized	(173)	(241)	(178)
<b>Net Interest Expense</b>	<b>168</b>	<b>53</b>	<b>97</b>
Effective Rate	6.2%	6.3%	6.4%

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

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

Interest capitalized on our major development projects was lower by \$68 million from 2006. We stopped capitalizing interest on the Syncrude Stage 3 expansion and Buzzard in 2007 as these projects were brought on stream. We expect to continue capitalizing interest on Long Lake and Ettrick until their planned completion in 2008. After that, we expect net interest expense to increase.

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

Our 2006 financing costs increased \$19 million from 2005. Additional borrowings to finance our 2006 capital program increased financing costs by approximately \$28 million. This was partially offset 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 Buzzard, Long Lake and Syncrude's Stage 3 expansion prior to its start-up.

**Income Taxes**

(Cdn\$ millions)	2007	2006	2005
Current	434	368	339
Future	358	315	(234)
<b>Total Provision for Income Taxes</b>	<b>792</b>	<b>683</b>	<b>105</b>
Disclosed as:			
Provision for Income Taxes—Continuing Operations	792	683	234
Provision for Income Taxes—Discontinued Operations <sup>1</sup>	–	–	(129)
<b>Total Provision for Income Taxes</b>	<b>792</b>	<b>683</b>	<b>105</b>
Effective Rate	42%	53%	8%

Note:

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

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

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

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

Effective January 1, 2006, the UK government increased the supplementary tax rate on our North Sea oil and gas activities from 10% to 20%, increasing the combined rate to 50%. This increased our future income tax liabilities, resulting in a charge of \$277 million during the first quarter of 2006. Federal and certain provincial governments in Canada also reduced corporate income tax rates in 2006, which lowered our future income tax liabilities by \$32 million. Our effective tax rate excluding the impact of these tax rate changes was 33%. Our current income tax provision included cash taxes in Yemen, the US, Colombia and Canada.

**Other**

(Cdn\$ millions)	2007	2006	2005
Decrease in Fair Value of Crude Oil Put Options	(43)	(11)	(196)
Block 51 Settlement	–	(151)	–
Business Interruption Insurance Proceeds	–	154	2
Gain on Dilution of Interest in Chemicals Business	–	–	193
Gain on Disposition of Oil and Gas Assets included as Discontinued Operations	–	–	225

During 2007, we purchased put options on 36 million barrels of our 2008 crude oil production. These options establish a Dated Brent floor price of US\$50/bbl on these volumes, are settled annually and provide downside price protection without limiting our upside to higher prices. Accounting rules require that these options be recorded at fair value throughout their term. As a result, changes in forward crude oil prices create gains or losses on these options at each period end. The put options were purchased for \$24 million; however, strong crude oil prices reduced the fair value of these options to nil, and we recorded a loss of \$24 million during the year.

During 2006, we purchased put options on approximately 105,000 bbls/d of our 2007 crude oil production for \$26 million. These options established a WTI floor price of US\$50/bbl on

these volumes. During 2006, an increase in the forward WTI prices lowered the fair value of the options and we recognized a loss of \$7 million for the year ended December 31, 2006. Strengthening WTI in 2007 reduced the market value of the options to nil, creating a loss of \$19 million in 2007.

Following our North Sea acquisition in late 2004, we purchased put options on 60,000 bbls/d of oil production for 2005 and 2006. These options created an average floor price for this production of US\$43.17/bbl in 2005 and US\$38.17/bbl in 2006. 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, causing us to expense \$4 million in 2006.

In 2006, a court of arbitration concluded that we breached an Area of Mutual Interest agreement with Occidental Petroleum Corporation (Occidental). As a result, Occidental was entitled to monetary damages. In late 2006, we settled the arbitration by agreeing to pay Occidental US\$135 million (\$151 million) as monetary damages. This amount was paid in the first quarter of 2007.

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

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.

### OUTLOOK FOR 2008

In 2008, we plan to invest \$2.4 billion in capital activities as follows:

- 29% in development projects to bring Long Lake Phase 1 and Ettrick in the North Sea on stream in 2008, and progress Longhorn in the Gulf of Mexico and CBM at Fort Assiniboine in Alberta;
- 17% on early-stage development projects expected to contribute production and cash flow growth beyond 2008. These include additional phases of oil sands in the Athabasca region, Usan offshore Nigeria, and our Knotty Head and Golden Eagle discoveries in the Gulf of Mexico and North Sea, respectively;
- 25% on exploration primarily in our North Sea and Gulf of Mexico growth areas; and
- 29% to exploit potential in our existing producing assets and in other corporate assets.

Details of our 2008 capital program are included in the Capital Investment section of the MD&A.

### Daily Production

In 2008 we expect additional production growth over 2007 and expect production to range between 220,000 and 240,000 boe/d (260,000 and 280,000 boe/d before royalties). In 2008, we expect to see the impact of a full year of Buzzard production and first oil from Ettrick in mid 2008. We are steaming the reservoir at Long Lake and expect bitumen production to ramp up in the spring, prior to upgrader start up mid 2008.

### 2008 Estimated Production

(mboe/d)	2008 Estimated Production		2007 Production	
	Before Royalties	After Royalties	Before Royalties	After Royalties
United States	25 – 30	20 – 25	33	29
United Kingdom	95 – 115	95 – 115	84	84
Yemen	50 – 55	27 – 32	72	40
Canada	45 – 50	40 – 45	37	30
Syncrude	20 – 25	17 – 22	22	19
Other International	6 – 7	5 – 6	6	5
<b>Total</b>	<b>260 – 280</b>	<b>220 – 240</b>	<b>254</b>	<b>207</b>

### Cash Flow and Sensitivities

We expect to generate approximately \$2.9 billion in cash flow from operating activities in 2008, after cash taxes of approximately \$1 billion, assuming the following:

WTI (US\$/bbl)	70.00
NYMEX Natural Gas (US\$/mmbtu)	6.75
Oil & Gas and Syncrude Operating Costs (Cdn\$/boe)	10.00
US to Canadian Dollar Exchange Rate	0.97

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

(Cdn\$ millions)

WTI—US\$1/bbl change above US\$50	39
WTI—US\$1/bbl change below US\$50	22
NYMEX Natural Gas—US \$0.50/mcf change	24
Exchange Rate—\$0.01 US/Cdn change	28

## LIQUIDITY AND CAPITAL RESOURCES

### Capital Structure

(Cdn\$ millions)	2007	2006
<b>Net Debt<sup>1</sup></b>		
Bank Debt	413	1,410
Public Senior Notes	3,758	2,885
Total Senior Debt	4,171	4,295
Subordinated Debt	439	536
Total Debt	4,610	4,831
Less: Cash and Cash Equivalents	(206)	(101)
<b>Total Net Debt</b>	<b>4,404</b>	<b>4,730</b>
<b>Shareholders' Equity<sup>2</sup></b>	<b>5,610</b>	<b>4,636</b>

Notes:

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

2 At January 31, 2008, there were 528,502,991 common shares and US\$460 million of unsecured subordinated securities outstanding. After November 8, 2008, we have the option to redeem these subordinated securities by issuing common shares. 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 and capital investment. We ended the year with net debt of \$4.4 billion, \$326 million lower than 2006. The decrease was primarily caused by the strengthening Canadian dollar relative to the US-dollar which reduced our US-dollar denominated debt by over \$700 million. The impact of foreign exchange was partially offset as our capital investment exceeded cash flow from operating activities by over \$500 million. This shortfall was financed with long-term debt.

In May 2007, we issued US\$250 million of 10-year senior notes and US\$1,250 million of 30-year senior notes and used the proceeds to repay amounts outstanding under term credit facilities. Issuing this debt extended the average term-to-maturity of our debt to 21 years. Approximately 7% of our long-term debt is repayable within the next three years.

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

(Cdn\$ millions)	2007	2006
Capital Investment	3,401	3,408
Cash Flow from Operating Activities	(2,830)	(2,374)
Excess of Capital Investment over Cash Flow	571	1,034
Dividends on Common Shares	53	52
Issue of Common Shares	(56)	(48)
Foreign Exchange Translation of US-dollar Debt and Cash	(745)	31
Net Proceeds on Disposition of Assets	(4)	(27)
Other	(145)	49
<b>Increase (Decrease) in Net Debt</b>	<b>(326)</b>	<b>1,091</b>

The change in our net debt has improved our 2007 leverage as reflected in the following ratios:

(times)	2007	2006	2005
Net Debt to Cash Flow from Operating Activities	1.6	2.0	1.7
Interest Coverage <sup>1</sup>	12.1	9.6	9.7

Note:

1 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 of conventional and unconventional resources, supplemented by strategic acquisitions when appropriate. Since most of our projects have long-cycle times, requiring significant amounts of capital prior to cash flow generation, we have successfully leveraged our balance sheet many times in the past, including to:

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

Each time, we exceeded our internal net debt to cash flow target band; however, we successfully brought our leverage down through asset sales and incremental cash flows. In 2006, we again increased our leverage investing in major development projects at Buzzard and Long Lake. With new cash flow from Buzzard in 2007, we reduced our ratio of net debt to cash flow from operating activities.

### Change in Working Capital

(Cdn\$ millions)	2007	2006	Increase/ (Decrease)
Cash and Cash Equivalents	206	101	105
Restricted Cash and Margin Deposits	203	197	6
Accounts Receivable	3,502	2,951	551
Inventories and Supplies	659	786	(127)
Future Income Tax Assets	18	479	(461)
Accounts Payable and Accrued Liabilities	(4,180)	(3,879)	(301)
Other	4	(1)	5
<b>Total</b>	<b>412</b>	<b>634</b>	<b>(222)</b>

Increased production rates and stronger commodity prices contributed to higher accounts receivable. Our marketing group reduced the amount of natural gas in storage at the end of 2007; however, this was partially offset by slightly higher crude oil inventories. New accounting rules require that the commodity inventory held by our energy marketing group be carried at fair value. These new rules also require us to reclassify \$51 million of critical spare parts for our oil and gas activities from inventories and supplies to property, plant and equipment. The current portion of future income tax assets decreased from 2006 as strong Buzzard production contributed to utilizing available tax losses in the UK. Stronger crude oil prices also increased accrued liabilities for our marketing operation. This increase was partially offset by lower stock-based compensation accruals.

The strengthening Canadian dollar relative to the US dollar impacted our US-dollar denominated working capital by reducing accounts receivable, inventories and accounts payable by approximately \$275 million, \$75 million and \$250 million, respectively.

### Liquidity

We generally rely on operating cash flows to fund capital requirements and provide liquidity. Given the long cycle-time of some of our development projects and volatile commodity prices, it is not unusual in any 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, 2007, we had unsecured term credit facilities of US\$3 billion that are available until 2012. At year end, \$211 million was drawn on these facilities and \$283 million of these facilities was utilized to support letters of credit. We also had \$665 million of uncommitted, unsecured credit facilities, of which \$196 million was supporting letters of credit at December 31, 2007.

From time to time, we access capital markets to meet our financing needs. We also use various financial instruments to minimize exposure to fluctuating commodity prices and foreign exchange. For example, we routinely purchase WTI put options to mitigate cash flow volatility. Overall, we manage our capital structure to maintain flexibility so we can fund our capital programs throughout 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)	2007	2006	2005	2004	2003
Cash Flow from Operating Activities	2,830	2,374	2,143	1,606	1,405
Cash Flow from Investing Activities	(3,281)	(3,388)	(1,864)	(4,013)	(1,219)
Surplus (Deficiency)	(451)	(1,014)	279	(2,407)	186
Cash Flow from Financing Activities	677	1,081	(274)	1,426	1,006
	<b>226</b>	<b>67</b>	<b>5</b>	<b>(981)</b>	<b>1,192</b>

In late 2003, we pre-funded debt repayments by raising more than \$1 billion in senior and subordinated debt. We used these funds in 2004 to repay higher-cost debt, and coupled with acquisition credit facilities, acquired the North Sea assets. In 2005, we used cash flow and proceeds from asset dispositions to fund our capital program and repay debt. In 2006, we borrowed approximately \$1 billion under our committed term credit facilities and used cash flow from operating activities to fund our capital program. In 2007, we issued US\$1.5 billion in senior debt to repay outstanding term credit facilities and \$150 million in medium term notes, and to partially fund our 2007 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 collateral be posted if adverse credit-related events, such as reduced credit ratings, occur. In evaluating our liquidity requirements, we consider the current requirements of our marketing business as well as additional collateral or other payments that could be required if our credit ratings were reduced.

#### Future Liquidity

Our future liquidity depends primarily on cash flow generated from our operations, existing committed credit facilities and our ability to access debt and equity markets. Assuming WTI

of US\$70/bbl, we expect our 2008 cash flow to exceed capital and dividend requirements by approximately \$400 million. In July 2008, we will repay \$125 million of medium term notes that become due with funds from our term credit facilities.

In 2008, we expect cash flow of approximately \$2.9 billion (before remediation and geological and geophysical expenditures) assuming:

WTI (US\$/bbl)	70.00
NYMEX Natural Gas (US\$/mmbtu)	6.75
US to Canadian Dollar Exchange Rate	0.97

Changes in commodity prices and exchange rates will impact our cash flow and borrowing requirements. Refer to the Outlook for 2008 section on page 62 to see how changes in the above assumptions can impact our cash flow.

A number of our development projects require capital to bring them on stream. In 2008, we expect to invest \$400 million to bring Long Lake Phase 1 on stream, \$165 million to progress our Usan development offshore Nigeria, and \$200 million to bring Ettrick in the North Sea on stream. 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. We also have a US\$2.5 billion shelf prospectus available in the US and Canada.

At December 31, 2007, the average term-to-maturity of our long-term debt was 21 years.

(Cdn\$ millions)	2008	2009	2010	2011	2012
Term Credit Facilities <sup>1</sup>	–	–	–	–	211
Canexus LP Term Credit Facilities	–	–	202	–	–
Medium Term Notes	125	–	–	–	–
<b>Total</b>	<b>125</b>	<b>–</b>	<b>202</b>	<b>–</b>	<b>211</b>

Note:

<sup>1</sup> \$3.0 billion available until 2012.

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

In the last four years, we declared common share dividends of \$0.10 per share each year.

### Contractual Obligations, Commitments and Guarantees

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

(Cdn\$ millions)	Payments				
	Total	<1 year	1-3 years	4-5 years	>5 years
Short-Term and Long-Term Debt	4,688	125	202	211	4,150
Interest on Long-Term Debt <sup>1</sup>	6,395	268	527	527	5,073
Operating Leases <sup>2</sup>	610	76	201	176	157
Capital Leases	117	5	10	10	92
Energy Commodity Contract Liabilities	576	413	135	25	3
Transportation and Storage Commitments <sup>2</sup>	922	368	271	151	132
Work Commitments and Purchase Obligations <sup>3</sup>	2,137	966	575	522	74
Asset Retirement Obligations	2,165	40	58	39	2,028
<b>Total</b>	<b>17,610</b>	<b>2,261</b>	<b>1,979</b>	<b>1,661</b>	<b>11,709</b>

Notes:

<sup>1</sup> Excludes interest on variable rate debt.

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

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

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

- Short-term and long-term debt amounts are included on our December 31, 2007 Consolidated Balance Sheet.
- Operating leases include the minimum lease payment obligations associated with leases for office space, rail cars, vehicles and processing agreements that allows our production to flow through third-party processing facilities.
- Capital leases include pipeline commitments primarily related to 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, 2007.

For certain contracts, we may net settle. These contracts are included in our Consolidated Balance Sheet at fair value.

- Work commitments include non-discretionary capital spending for drilling, seismic, facilities construction and other development commitments in our international operations, and includes Long Lake (\$192 million) and Ettrick in the North Sea (\$139 million). Since the timing of certain payments is difficult to determine with certainty, the table was prepared using our best estimates. The remainder of our 2008 capital investment is discretionary.
- We have included \$821 million in work commitments for drilling rigs we have contracted in the North Sea and Gulf of Mexico, over the next five years.
- We have \$2,165 million of undiscounted asset retirement obligations after inflation. As of December 31, 2007, the discounted value (\$832 million) of these estimated obligations was provided for in our Consolidated Financial Statements (including \$40 million of current liabilities). Since timing of any payments is difficult to determine with certainty, the table was prepared using our best estimates.

- We have unfunded obligations under our defined benefit pension plans of \$130 million (Nexen—\$72 million; Canexus—\$7 million; Syncrude—\$51 million). Our obligations for Nexen and Canexus include \$63 million that is unfunded as a result of statutory limitations. These obligations are backed by irrevocable letters of credit.
- We have excluded obligations on our tandem option and stock appreciation rights programs as the amount and timing of cash payments are not determinable.
- We have excluded our normal purchase arrangements as they are discretionary and are reflected in our expected cash flow from operating activities and capital expenditures for 2008.
- We have excluded our future income tax liabilities as the amount and timing of any cash payment for income taxes is based on taxable income for each fiscal year in the various jurisdictions where we operate. We have also excluded future income tax liabilities as they relate to uncertain tax positions, as we cannot provide a reasonable estimate as to if, or when future payments would be required.

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

#### **Credit Ratings**

Currently, our senior debt is rated Baa2 by Moody's Investor Service, Inc. (Moody's), BBB by Dominion Bond Rating Service (DBRS) and BBB- by Standard & Poor's (S&P). 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 energy marketing group enters into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. The agreements normally require collateral to be posted if an adverse credit-related event, such as a drop in credit ratings, occurs. Based on contracts in place and commodity prices at December 31, 2007, we could be required to post collateral of up to \$1.2 billion if we were downgraded to non-investment grade. These obligations are reflected on our balance sheet. The posting of collateral merely accelerates the payment of such amounts. Just as we may be required to post collateral if we were downgraded below investment grade, we have similar provisions in many of our contracts that allow us to demand certain counterparties post collateral for amounts they owe us if they are downgraded to non-investment grade.

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

We have no off-balance sheet arrangements that would have a material adverse effect on our liquidity, consolidated financial position or results of operations. We use operating leases in the normal course of business as disclosed in Contractual Obligations, Commitments and Guarantees on page 66 and in Note 15 to the Consolidated Financial Statements, which is incorporated herein by reference.

At December 31, 2007, we had outstanding letters of credit supported by \$283 million of unsecured term credit facilities and \$196 million of uncommitted unsecured credit facilities.

#### **Contingencies**

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

### CRITICAL ACCOUNTING ESTIMATES

We make estimates and assumptions that affect: 1) the reported amounts of our assets and liabilities; 2) the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements; and 3) 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 judgments and decisions based on available geological, geophysical, engineering and economic data. To estimate the economically recoverable oil and natural gas reserves and related future net cash flows, we incorporate many factors and assumptions including:

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

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

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

The nature and extent of the independent evaluations and audits, and the results thereof, are provided in the section on Reserves, Production and Related Information on page 16.

The board of directors has a Reserves Review Committee (Reserves Committee) to assist the board and the Audit and Conduct Review Committee to oversee the annual review of our oil and gas and Syncrude reserves and disclosures of reserves data and related oil and gas and mining activities. The Reserves Committee is comprised of three or more directors, the majority of whom are independent and familiar with estimating oil and gas reserves. The Reserves Committee meets with management periodically to review the reserves process, the portfolio of properties selected by management for independent assessment, results and related disclosures. The Reserves Committee appoints and meets with 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 our 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, 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 2007, \$126 million of our total \$360 million spent on exploration drilling was expensed. If none of our exploration drilling had been successful, our net income would have decreased by \$150 million, net of income tax.
- calculating our unit-of-production depletion rates. Both proved and proved developed reserves estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense. Proved reserves are used where a property is acquired and proved developed reserves are used where a property is drilled and developed. In 2007, oil and gas depletion of \$1,213 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 \$121 million, assuming no other changes to our reserves profiles.
- assessing, when necessary, our oil and gas assets for impairment. Estimated future undiscounted cash flows are determined using proved reserves. The critical estimates used to assess impairment, including the impact of changes in reserves estimates, are discussed below.

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

## Impairments

### Property, Plant and Equipment

We evaluate our long-lived assets (oil and gas properties, Syncrude and chemicals) for impairment if an adverse event or change occurs. Among other things, 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 flow for a property is 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.

Cash flow estimates for our impairment assessments require assumptions about two primary elements—future prices and reserves. Our estimates of future prices require significant judgments about highly uncertain future events. Historically, oil and gas prices have exhibited significant volatility—over the last five years, prices for WTI and NYMEX gas have ranged from US\$25.24/bbl to US\$99.62/bbl and US\$4.20/mmbtu to US\$15.38/mmbtu, respectively. Our forecasts for oil and gas revenues are based on prices derived from a consensus of future price forecasts amongst industry analysts and our own assessments. Our estimates of future cash flows are generally based on our assumptions of long-term prices and 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 businesses with the exception of chemicals and energy marketing.

It is difficult to determine and assess how a decrease in proved reserves impacts our impairment tests. The relationship between 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.

### Goodwill

We test goodwill for impairment annually based on estimated future cash flows of the reporting unit to which the goodwill is attributable. In addition, we test goodwill for impairment whenever an event or circumstance occurs that may reduce the fair value of a reporting unit below its carrying amount. If our goodwill is impaired, we write it down to its implied fair

value, based on the fair value of the assets and liabilities of the underlying reporting unit. The process of assessing goodwill for impairment necessarily requires us to determine the fair values of our assets and liabilities, and involves making various assumptions and judgments.

#### **Asset Retirement Obligations**

We are required to remove or remedy the effect of our activities on the environment at our present and former operating sites by dismantling and removing production facilities and remediating any damage caused. In estimating our future asset retirement obligations, we must make estimates and judgments on activities that will occur many years into the future. Also, 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 where we operate.

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

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

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

We account for business acquisitions using the purchase method of accounting. Under this method, we are 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 is recorded as goodwill.

We make various assumptions and judgments in determining the fair values of the acquired company's assets and liabilities,

the most significant of which are in estimating the fair value of the oil and gas properties. To determine the fair value of these properties, we estimate (a) oil and gas reserves using our reserve standards, (b) additional reserves potential and (c) future prices of oil and gas.

Our reserve estimates are based on work performed by our engineers and outside consultants. Judgements 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 are based on prices derived from a consensus of future price forecasts among industry analysts and our own assumptions. The judgments associated with these estimates are described earlier in our critical accounting estimates discussion entitled "Impairments—Property, Plant and Equipment".

We apply our estimated future prices to the estimated reserves quantities acquired, and we estimate future operating and development costs to arrive at estimated future net revenues for the properties acquired. For proved properties, we discount the future net revenues using after-tax discount rates. The same principles are 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 is applied to the discounted future net revenues of the probable and possible reserves in each particular instance.

#### **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 adequately provided for all income tax obligations. However, changes in facts and circumstances as a result of income tax audits, reassessments, jurisprudence and any new legislation may result in an increase or decrease in our provision for income taxes.

## NEW ACCOUNTING PRONOUNCEMENTS

### Canadian Pronouncements

In December 2006, the Canadian Accounting Standards Board (AcSB) issued two new Sections relating to financial instruments: Section 3862, *Financial Instruments—Disclosures*, and Section 3863, *Financial Instruments—Presentation*. Both sections are effective for annual and interim periods beginning on or after October 1, 2007 and 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 and will require additional disclosure.

In February 2008, the AcSB issued Section 3064, *Goodwill and Intangible Assets* and amended Section 1000, *Financial Statement Concepts* clarifying the criteria for the recognition of assets, intangible assets and internally developed intangible assets. Items that no longer meet the definition of an asset are no longer recognized as assets. The standard is effective for fiscal years beginning on or after October 1, 2008 and early adoption is permitted. We are currently evaluating the impact these sections will have on our results of operations or financial position.

In January 2006, the AcSB adopted a strategic plan for the direction of accounting standards in Canada. Accounting standards for public companies in Canada are expected to converge with the International Financial Reporting Standards by 2011. The timing for convergence has not been confirmed by the AcSB. We continue to monitor and assess the impact of these convergence efforts.

### US Pronouncements

In September 2006, the Financial Accounting Standards Board (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. For fiscal years beginning after November 15, 2007, companies must implement the standard for financial assets and liabilities, as well as for any other assets and liabilities carried at fair value on a recurring basis in financial

statements. However, a one year deferral for the implementation of Statement 157 is provided for other non financial assets and liabilities. We do not expect the adoption of this statement to materially impact our results of operations or financial position.

Effective December 31, 2006, we adopted the recognition and disclosure provisions of FASB Statement 158, *Employers' Accounting for Defined Benefit Pension And Other Postretirement Plans*. This statement also requires we measure the funded status of a plan as of the balance sheet date. The measurement provisions of the statement are effective for fiscal years ending after December 15, 2008. We do not expect the adoption of the change in measurement date in 2008 to materially impact our results of operations or financial position.

In February 2007, FASB issued Statement 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. The statement allows for the elective measurement of eligible financial instruments and certain other items at fair value in order to mitigate volatility in reported earnings without having to apply complex and detailed hedge accounting rules. This statement is effective for fiscal years beginning after November 15, 2007. We do not expect the adoption of this statement to materially impact our results of operations or financial position.

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

In December 2007, FASB issued Statement 160, *Noncontrolling Interests in Consolidated Financial Statements*, an amendment of ARB. No 51. This statement clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. This statement is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption of this statement to materially impact 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 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 exploration and development.

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

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

In 2007, WTI averaged US\$72.31/bbl, reaching a high of US\$99.29/bbl and a low of US\$49.90/bbl. Dated Brent, on which approximately 80% of our production is priced, averaged \$72.52/bbl, reaching a high of US\$96.02/bbl and a low of US\$50.68/bbl. NYMEX natural gas prices averaged US\$7.12/mmbtu in 2007, reaching a high of US\$8.71/mmbtu and a low of US\$5.19/mmbtu. Our sensitivities to commodity prices and the expected impact on our 2008 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	39	36
WTI—US\$1/bbl change below US\$50	22	20
NYMEX Natural Gas—US\$0.50/mcf change	24	20

These sensitivities are based on our estimated 2008 oil and gas production and assume a Canadian/US dollar exchange rate of \$0.97. Our estimated oil and gas production range for 2008 is between 260,000 and 280,000 boe/d before royalties, of which approximately 16% is gas.

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

In 2007, we purchased Dated Brent put options to manage the commodity price risk exposure on a portion of our oil production in 2008, by establishing an annual average Dated Brent floor price of US\$50/bbl on 36 million barrels or about 100,000 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 \$0.93 in 2007, ranging from a low of \$0.84 to a high of \$1.09.

Our sensitivities to the US dollar and the expected impact of a one cent change on our 2008 cash flow from operating activities, net income, capital expenditures and long-term debt is as follows:

(Cdn\$ millions)	Cash Flow	Net Income	Capital Expenditures	Long-term Debt
\$0.01 Change in US to Cdn	28	17	15	44

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 2008. These estimates are based on a WTI price for crude oil of US\$70/bbl, a NYMEX natural gas price of US\$6.75/mmbtu, operating costs of \$10/boe and a Canadian/US dollar exchange rate of \$0.97.

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

Our chemicals operations are exposed to changes in the US-dollar exchange rate as part of their sales are denominated in US-dollars. Canexus periodically purchases US-dollar call options to reduce this exposure. Under outstanding option contracts at December 31, 2007, Canexus had the right to sell US\$5 million monthly and purchase Canadian dollars at an exchange rate of US\$0.95 to February 29, 2008.

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 2008 cash flow from operating activities and net income is as follows:

(Cdn\$ millions)	Cash Flow	Net Income
Interest Rates—1% change in rates	5	3

Our sensitivity to changes in interest rates is based on 2008 estimated average floating rate debt of \$475 million and a Canadian/US dollar exchange rate of \$0.97.

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, 2007, fixed-rate borrowings comprised 91% (2006—73%) of our long-term debt at an effective average rate of 6.3% (2006—6.3%). During the year, we periodically borrow under our committed, unsecured, term credit facilities and at December 31, 2007, floating-rate debt comprised 9% (2006—27%) of our long-term debt at an effective average rate of 5.8% (2006—5.7%) ranging from a low of 4.2% to a high of 8.75% during 2007.

We had no interest rate swaps outstanding in 2007 or 2006.

### TRADING

#### Commodity Price Risk

Our marketing group markets and trades crude oil, natural gas, NGLs, ethanol and power through 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. Our energy marketing group actively manages this risk by utilizing energy-related futures, forwards, swaps and options, as well as currency swaps or forwards. We typically take advantage of location, time and quality spreads using physical and financial contracts. The marketing group 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 change 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 when 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.

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 primarily by using the Variance-Covariance method based on historical commodity price volatility, correlation inputs where available and by historical simulation in other situations. Our estimate is based upon the following key assumptions:

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

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. 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 \$3.6 and \$6.1 million in 2007.

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

(Cdn\$ millions)	2007	2006	2005
<b>Value at Risk</b>			
Year End	26	26	24
High	38	33	28
Low	24	17	11
Average	30	23	21

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 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, 2007:

- over 96% of our credit exposures were investment grade; and
- only three counterparties individually made up more than 5% of our credit exposure, one of which made up more than 10%. All three 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*, constitute "forward-looking statements" (within the meaning of the United States *Private Securities Litigation Reform Act* of 1995, Section 21E of the United States *Securities Exchange Act of 1934*, as amended, and Section 27A of the United States *Securities Act of 1933*, as amended) or "forward-looking information" (within the meaning of applicable Canadian securities legislation). Such statements or information (together "forward-looking statements") are generally identifiable by the terminology used such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook" or other similar words and include statements relating to or associated with individual wells, regions or projects. Any statements regarding the following are forward-looking statements:

- future crude oil, natural gas or chemicals prices;
- future production levels;
- future cost recovery oil revenues from our Yemen operations;
- future capital expenditures and their allocation to exploration and development activities;
- future earnings;
- future asset dispositions;
- future sources of funding for our capital program;
- future debt levels;
- possible commerciality;
- development plans or capacity expansions;
- future ability to execute dispositions of assets or businesses;
- future cash flows and their uses;
- future drilling of new wells;
- ultimate recoverability of reserves or resources;
- expected finding and development costs;
- expected operating costs;
- future demand for chemicals products;
- estimates on a per share basis;
- sales;
- future expenditures and future allowances relating to environmental matters;
- dates by which certain areas will be developed or will come on stream; and
- changes in any of the foregoing.

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

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others:

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

These 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 factors are interdependent, and management's future course of action would depend on our assessment of all information at that time.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity and achievements. Undue reliance should not be placed on the statements contained herein, which are made as of the date hereof and, except as required by law, Nexen undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

**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 Canada, *National Instrument 51-101—Standards of Disclosure for Oil and Gas Activities* (NI 51-101) prescribes that Canadian companies follow certain standards for the preparation and disclosure of reserves and related information. Our disclosures may differ from other Canadian companies as we have received exemptions under NI 51-101 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 268 million barrels before royalties of proved bitumen reserves (234 million barrels after royalties) under SEC requirements, whereas under NI 51-101 we would have recognized 218 million barrels before royalties of proved synthetic reserves (210 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.

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

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

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