FIRST QUARTER 2007

Report to shareholders for the period ended March 31, 2007

FIRST IN oil sands
STILL taking the lead

Suncor Energy reports strong financial performance Oil sands growth plans on schedule and on budget

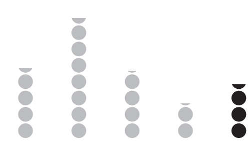
All financial figures are unaudited and in Canadian dollars unless noted otherwise. Certain financial measures referred to in this document are not prescribed by generally accepted accounting principles (GAAP). For a description of these measures, see "Non-GAAP Financial Measures" in Suncor's 2007 first quarter management's discussion and analysis. This document makes reference to barrels of oil equivalent (boe). A boe conversion ratio of six thousand cubic feet of natural gas: one barrel of crude oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Accordingly, boe measures may be misleading, particularly if used in isolation.

Suncor Energy Inc. recorded first quarter 2007 net earnings of $551 million ($1.20 per common share), compared to $713 million ($1.56 per common share) in the first quarter of 2006. Excluding the impact of net insurance proceeds accrued in 2006 and the effects of unrealized foreign exchange gains on the company's U.S. dollar denominated long-term debt, first quarter 2007 net earnings were $539 million ($1.17 per common share), compared to $509 million ($1.11 per common share) in the first quarter of 2006. Cash flow from operations was $790 million in the first quarter of 2007, compared to $1.314 billion in the first quarter of 2006.

Excluding the impact of insurance proceeds accrued in 2006, the increase in net earnings was primarily due to strong retail and refining margins in downstream operations, lower Alberta Crown royalty expenses and lower effective federal and provincial income tax rates.

These positive factors were partially offset by lower oil sands production and higher operating expenses, both related to unplanned maintenance at the oil sands facility during the quarter. Reduced earnings in Suncor's Natural Gas business also negatively impacted earnings.

Earnings by Quarter
($ millions)

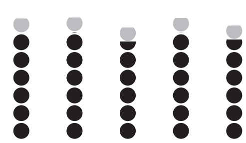


	2006 Q1	2006 Q2	2006 Q3	2006 Q4	**2007 Q1**
	713	1 218	682	358	**551**

Cash Flow from Operations by Quarter
($ millions)

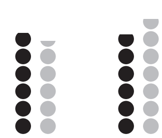
	2006 Q1	2006 Q2	2006 Q3	2006 Q4	**2007 Q1**
	1 314	1 320	1 153	746	**790**

Production
(thousands of barrels of oil equivalent per day)



	2006 Q1	2006 Q2	2006 Q3	2006 Q4	**2007 Q1**
Natural Gas	35.9	35.1	34.6	34.7	**34.9**
Oil Sands	264.4	267.3	242.8	266.4	**248.2**
Total	300.3	302.4	277.4	301.1	**283.1**

Ratios
(per cent)
for the twelve months ended March 31



	2006	**2007**
Return on average shareholder's equity	30.9	**30.5**
Return on capital employed	28.5	**35.1**

Suncor's total upstream production averaged 283,100 barrels of oil equivalent (boe) per day during the first quarter of 2007, compared to 300,300 boe per day in the first quarter of 2006. Oil sands production during the first quarter averaged 248,200 barrels per day (bpd) compared to first quarter 2006 production of 264,400 bpd. Natural gas production in the first quarter of 2007 was 209 million cubic feet equivalent (mmcfe) per day, compared to first quarter 2006 production of 215 mmcfe per day.

During the first quarter, oil sands cash operating costs averaged $26.30 per barrel, compared to $19.05 per barrel during the first quarter of 2006. The increase in cash operating costs was due to higher operating expenses being applied to a lower production volume.

As a result of lower than planned production in the first quarter, Suncor has revised its outlook for 2007. Production is now targeted at 255,000 bpd to 265,000 bpd, down slightly from original targets of 260,000 bpd to 270,000 bpd. Cash operating cost targets have been adjusted upward to $23.50 to $24.50 per barrel from $21.50 to $22.50 per barrel.

In Suncor's downstream operations, refining and retail margins were higher in the first quarter of 2007 compared to the first quarter of 2006 due to tighter supply of refined products in both the Ontario and U.S. Rocky Mountain markets. Total refinery throughput increased compared to the first quarter of 2006, when Suncor's U.S. operations were impacted by planned maintenance.

Growth update

Suncor's next major growth phase includes an expansion of existing upgrading facilities that targets an increase in production capacity to 350,000 bpd in 2008. Engineering on this portion of the project is substantially complete and construction is approximately 75% complete. The project remains on schedule and on budget.

A targeted 50-day shutdown to Upgrader 2 to tie-in new facilities related to the expansion is expected to begin on May 31. During the tie-in work, Upgrader 1 is expected to continue normal production.

Work underway also includes the expansion of Suncor's Firebag in-situ operations, with construction targeted for completion in 2007. The project, which is expected to increase the bitumen production capacity of Firebag Stages 1 and 2 by about 35%, also includes the addition of cogeneration facilities. The cogeneration portion of the project is complete with the balance of project construction approximately 65% complete.

"The current expansion of bitumen production and upgrading capacity is an important step in the Voyageur growth plan we launched in 2001," said Rick George, president and chief executive officer. "We are well on our way toward targeted production of more than half a million barrels per day."

Suncor's plans to increase production to 500,000 bpd to 550,000 bpd in 2010 to 2012 involve a number of investments including increased bitumen production from mining and in-situ sources, additional facility infrastructure and a third oil sands upgrader. Plans are proceeding on schedule, with fabrication of major vessels for the planned upgrader underway.

In Suncor's downstream operations, work continues on modifications to the company's Sarnia refinery, which are planned to enable the facility to process up to 40,000 bpd of oil sands sour crude. The budget for the project has been increased to $960 million from $800 million due to labour shortages and material supply issues. A shutdown to tie-in new facilities is planned for the third quarter with completion targeted for the fourth quarter. Portions of the refinery are expected to continue production during the shutdown period.

"Although our longer-term growth plans remain on track, we're continuing to see significant capital cost pressures across our business," said George. "We will maintain, with our business partners, a sharp focus on the pieces of the cost equation we can control."

As Suncor invests for future growth, prudent debt management remains a priority. Net debt levels increased to $2.3 billion at the end of the first quarter from $1.9 billion at year-end 2006.

"We are well on our way toward targeted production of more than half a million barrels per day." **Rick George,** president and chief executive officer

Outlook

Suncor's outlook provides management's targets for 2007 in certain key areas of the company's business. Outlook forecasts, which are updated quarterly, are subject to change.

	Three months ended March 31, 2007	2007 Full Year Outlook
Oil Sands		
Production (bpd) (1)	**248 200**	255 000 to 265 000
Diesel	**12%**	10%
Sweet	**41%**	42%
Sour	**44%**	43%
Bitumen	**3%**	5%
Realization on crude sales basket	**WTI @ Cushing less Cdn$2.44 per barrel**	WTI @ Cushing less Cdn$7.50 to $8.50 per barrel
Cash operating costs (2)	**$26.30 per barrel**	$23.50 to $24.50 per barrel
Natural Gas		
Natural gas production (3) (mmcf equivalent per day)	**209**	215 to 220

(1) The 2007 production outlook has been revised from original targets of 260,000 to 270,000 bpd. The 2007 oil sands production target includes approximately 5% non-upgraded bitumen sold directly to the market. In 2006, the production target referred only to synthetic crude oil production.

(2) The 2007 cash operating cost outlook has been revised from original targets of $21.50 to $22.50 per barrel. Cash operating cost estimates are based on the following assumptions: i) production of 255,000 bpd to 265,000 bpd; ii) a production sales mix as described in the chart above; and iii) a natural gas price of US$7.60 per thousand cubic feet (mcf) at Henry Hub. Cash operating costs per barrel are not prescribed by generally accepted accounting principles (GAAP). This non-GAAP financial measure does not have any standardized meaning and therefore is unlikely to be comparable to similar measures presented by other companies. Suncor includes this non-GAAP financial measure because investors may use this information to analyze operating performance. This information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. See "Non-GAAP Financial Measures" on page 13 Suncor's first quarter 2007 Report to Shareholders.

(3) The 2007 production target includes natural gas liquids (NGL) and crude oil converted into mmcf equivalent at a ratio of one barrel of NGL/crude oil: six thousand cubic feet of natural gas.

Factors that could potentially impact Suncor's financial performance include:

- Crude oil hedges. Suncor has hedging agreements for 60,000 bpd in 2007 and 10,000 bpd in 2008. These costless collar hedges have an average floor of approximately US$51.64 per barrel while allowing participation in higher crude oil prices with an average ceiling of approximately US$101.06 per barrel. The company will consider costless collars totalling up to 30% of annual planned crude oil production if strategic opportunities are available.
- Scheduled tie-ins of modified facilities at Suncor's oil sands operation are planned to begin May 31, 2007. Upgrader 2 is expected to be shutdown for approximately 50 days while this work is underway. During the outage, Upgrader 1 is expected to continue normal production. Although this shutdown is reflected in operational targets for the year, production estimates could be impacted if the work takes longer than planned or is impacted by labour or material supply issues. The tie-in work is required to enable production capacity to be increased to a planned 350,000 bpd in 2008.
- Scheduled tie-ins of modified facilities at Suncor's refineries. Suncor plans to begin a shutdown of the Sarnia refinery in the third quarter of 2007 (with completion scheduled in the fourth quarter of 2007) to tie-in modified facilities that are expected to enable the facility to process up to 40,000 bpd of oil sands sour crude.

Information on risks, uncertainties and other factors that could affect these plans is included in Suncor's annual report to shareholders and other documents filed with regulatory authorities.

Management's discussion and analysis

April 26, 2007

This Management's Discussion and Analysis (MD&A) contains forward-looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. See page 15 for additional information.

This MD&A should be read in conjunction with our March 31, 2007 unaudited interim consolidated financial statements and notes. Readers should also refer to our MD&A on pages 18 to 60 of our 2006 Annual Report and to our Annual Information Form (AIF), dated February 28, 2007. All financial information is reported in Canadian dollars (Cdn$) and in accordance with Canadian generally accepted accounting principles (GAAP) unless noted otherwise. The financial measures cash flow from operations, return on capital employed (ROCE) and cash and total operating costs per barrel referred to in this MD&A are not prescribed by GAAP and are outlined and reconciled in Non-GAAP Financial Measures on page 58 of our 2006 Annual Report and page 13 of this MD&A.

Certain amounts in prior years have been reclassified to enable comparison with the current year's presentation.

Barrels of oil equivalent (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet (mcf) of natural gas: one barrel of crude oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

References to "we," "our," "us," "Suncor," or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships and joint venture investments, unless the context otherwise requires.

The tables and charts in this document form an integral part of this MD&A.

Additional information about Suncor filed with Canadian securities commissions and the United States Securities and Exchange Commission (SEC), including periodic quarterly and annual reports and the AIF filed with the SEC under cover of Form 40-F, is available on-line at www.sedar.com, www.sec.gov and our website www.suncor.com. Information contained in or otherwise accessible through our website does not form a part of this MD&A. All such references are inactive textual references only.

In order to provide shareholders with full disclosure relating to potential future capital expenditures, we have provided cost estimates for significant capital projects that, in some cases, are still in the early stages of development. These costs are estimates only. The actual amounts may differ and these differences may be material. For a further discussion of our significant capital projects and the range of cost estimates associated with an "on-budget" project, see the "Significant Capital Project Update" on page 11.

Selected financial information

Industry Indicators (average for the period)	3 months ended March 31 **2007**	 2006
West Texas Intermediate (WTI) crude oil US$/barrel at Cushing	**58.15**	63.50
Canadian 0.3% par crude oil Cdn$/barrel at Edmonton	**67.45**	69.10
Light/heavy crude oil differential US$/barrel WTI Cushing less Lloyd Blend at Hardisty	**16.95**	29.00
Natural Gas US$/mcf at Henry Hub	**6.95**	9.05
Natural Gas (Alberta spot) Cdn$/mcf at AECO	**7.45**	9.25
New York Harbour 3-2-1 crack (1) US$/barrel	**11.35**	7.10
Exchange rate: Cdn$:US$	**0.85**	0.87

(1) New York Harbour 3-2-1 crack is an industry indicator measuring the margin on a barrel of oil for gasoline and distillate. It is calculated by taking two times the New York Harbour gasoline margin plus one times the New York Harbour distillate margin and dividing by three.

Outstanding Share Data (as at March 31, 2007)	
Common shares	460 218 676
Common share options – total	21 388 830
Common share options – exercisable (1)	9 636 762

(1) Options which have vested and are available for exercise.

Summary of Quarterly Results

($ millions, except per share data)	2007 quarter ended Mar. 31	2006 quarter ended Dec. 31	Sept. 30	June 30	Mar. 31	2005 quarter ended Dec. 31	Sept. 30	June 30
Revenues	**3 951**	3 787	4 114	4 070	3 858	3 521	3 149	2 385
Net earnings	**551**	358	682	1 218	713	693	315	83
Net earnings attributable to common shareholders per share								
Basic	**1.20**	0.78	1.48	2.65	1.56	1.52	0.69	0.18
Diluted	**1.17**	0.76	1.45	2.59	1.52	1.48	0.67	0.18

Analysis of Consolidated Statements of Earnings and Cash Flows

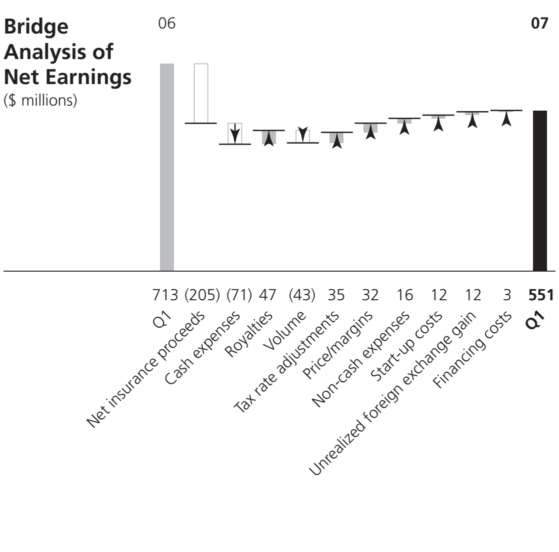
Net earnings for the first quarter of 2007 were $551 million, compared to $713 million for the first quarter of 2006 ($509 million after adjusting for unrealized foreign exchange gains and $205 million in insurance proceeds accrued in the first quarter of 2006 related to the January 2005 fire at our oil sands facility). Excluding the impact of net insurance proceeds accrued in 2006, the increase in comparable net earnings was primarily due to strong refining and retail margins in our downstream operations, lower Alberta Crown royalty expenses and lower effective federal and provincial income tax rates.

These positive factors were partially offset by lower oil sands production and higher operating expenses, both related to unplanned maintenance at the oil sands facility during the quarter. Lower earnings in our Natural Gas business as a result of lower natural gas prices reflecting lower benchmark commodity prices, also negatively impacted earnings in the first quarter of 2007.

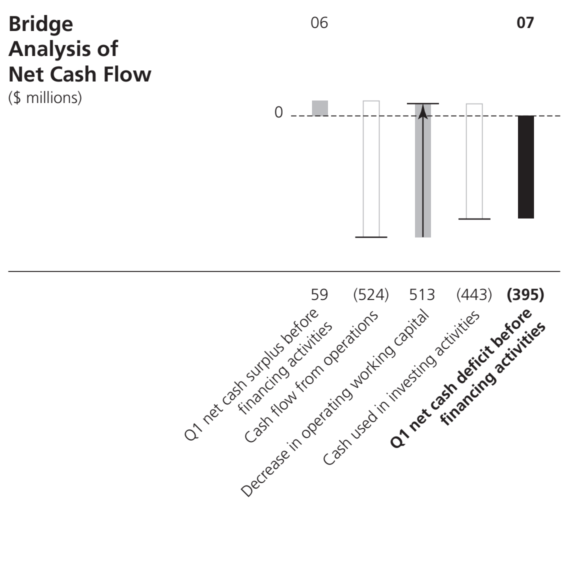
Cash flow from operations in the first quarter of 2007 was $790 million, compared to $1,314 million in the same period of 2006. Cash flow from operations was lower due to the same factors that impacted net earnings, as well as an increase in cash income tax expenses in all of our operating business segments in the first quarter of 2007 compared to the first quarter of 2006 notwithstanding a decrease in our effective income tax rate.

Our effective tax rate for the first three months of 2007 was 30%, compared to 37% in the first three months of 2006. The first quarter 2007 effective tax rate is consistent with our expectations. The lower effective tax rate in 2007 was due to reductions in both the federal and provincial rates enacted in the second quarter of 2006. During 2007, we expect our Oil Sands and Natural Gas businesses will be partially cash taxable. During the first quarter we recorded $162 million in current income tax expense compared to a recovery of $1 million in the first quarter of 2006 (see page 7 for a more detailed discussion).

Bridge Analysis of Net Earnings
($ millions)



Bridge Analysis of Net Cash Flow
($ millions)



Net Earnings Components

This table explains some of the factors impacting net earnings on an after-tax basis. For comparability purposes, readers should rely on the reported net earnings presented in our unaudited interim consolidated financial statements and notes in accordance with Canadian GAAP.

($ millions, after-tax)	**Q1 2007**	Q1 2006
Net earnings before the following items	**539**	522
Firebag in-situ start-up costs	**—**	(13)
Oil Sands fire accrued insurance proceeds (1)	**—**	205
Unrealized foreign exchange gain (loss) on U.S. dollar denominated long-term debt	**12**	(1)
Net earnings as reported	**551**	713

(1) Accrued business interruption proceeds net of income taxes and Alberta Crown royalties.

Analysis of Segmented Earnings and Cash Flow

Oil Sands

Oil Sands recorded 2007 first quarter net earnings of $453 million, compared with $707 million in the first quarter of 2006 ($502 million excluding net insurance proceeds of $205 million). Net earnings were lower primarily as a result of lower oil sands production and sales volumes combined with higher operating expenses, both related to unplanned maintenance at the oil sands facility during the quarter.

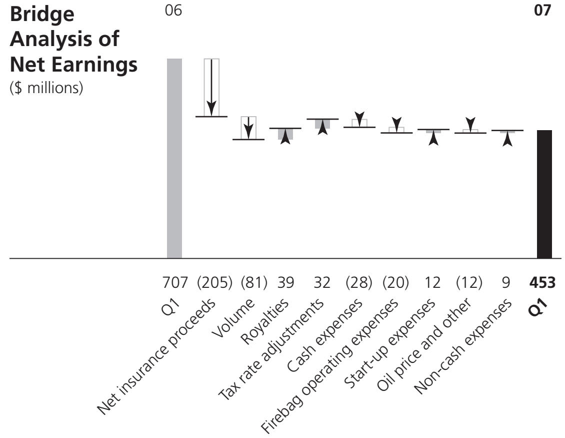
These negative impacts were partially offset by:

- Lower Alberta Crown royalty expense as a result of lower production, higher operating and capital costs, and the absence of insurance proceeds subject to Crown royalties.
- Lower effective federal and Alberta provincial income taxes as a result of the reduction of federal and provincial rates in the second quarter of 2006. In addition, the absence of taxable insurance proceeds in 2007 also reduced our effective income tax rates.

Operating expenses before tax were $612 million in the first quarter of 2007 compared to $526 million in the first quarter of 2006. The increase in operating expenses was primarily due to unplanned maintenance in the first quarter of 2007. Operating expenses in the first quarter of 2007 also increased due to the inclusion of three months of costs associated with Firebag Stage 2; in 2006, Firebag Stage 2 was in commercial operations for only part of the first quarter. These factors were partly offset by lower sales volumes in the first quarter of 2007 compared to the first quarter of 2006.

Depreciation, depletion and amortization expense was $100 million in the first quarter of 2007 compared to $93 million during the same period in 2006. The increase resulted from continued growth in the depreciable cost base for our oil sands facilities.

Bridge Analysis of Net Earnings
($ millions)



Alberta Crown royalty expense was $157 million in the first quarter of 2007 compared to $285 million in the first quarter of 2006. The decrease was due mainly to the lower sales revenues during the first three months of 2007 compared to the same period in 2006, an increase in anticipated eligible expenditures for 2007, and the absence of insurance proceeds subject to Crown royalties. See page 7 for a discussion of Alberta Oil Sands Crown royalties.

Cash flow from operations was $578 million in the first quarter of 2007, compared to $1,209 million in the first quarter of 2006. Excluding the impact of depreciation, depletion and amortization, the decrease was due to the same factors that impacted net earnings, in addition to cash taxes incurred during the first three months of 2007 that were not present in the first quarter of 2006.

Oil Sands production averaged 248,200 barrels per day (bpd). First quarter production was lower than full capacity due to unplanned maintenance. Comparative production during the first quarter of 2006 averaged 264,400 bpd. As a result of the production issues encountered during the first quarter of 2007, we have revised our 2007 annual production outlook downward to 255,000 bpd to 265,000 bpd from 260,000 bpd to 270,000 bpd.

Sales volumes during the first quarter of 2007 averaged 254,500 bpd, compared with 275,300 bpd during the first quarter of 2006. The proportion of higher value diesel fuel and sweet crude products decreased to 53% of total sales volumes in the first quarter of 2007, compared to 56% in the first quarter of 2006, reflecting operational constraints.

The average price realization for Oil Sands crude products was relatively unchanged at $65.70 per barrel in the first quarter of 2007, compared to $65.75 per barrel in the first quarter of 2006. An 8% decrease in average benchmark WTI crude oil prices was offset by the narrowing of differentials on our sweet and sour crude blends as a result of production issues at both our facility and at other oil sands producers during the first quarter of 2007. As a result, per barrel prices for our oil sands synthetic crude oil averaged $2.44 below WTI, compared to our outlook expectations of $7.50 to $8.50 below WTI for 2007. We have not adjusted our full year outlook for sales realizations.

During the first quarter of 2007, cash operating costs averaged $26.30 per barrel, compared to $19.05 per barrel during the first quarter of 2006. The increase in cash operating costs per barrel is due to a combination of higher cash operating expenses, reflecting unplanned maintenance, being applied to a lower production volume. As a result, we have revised our full year outlook for 2007 cash operating costs per barrel upward to $23.50 to $24.50 from $21.50 to $22.50. Refer to page 13 for further details on cash operating costs as a non-GAAP financial measure, including the calculation and reconciliation to GAAP measures.

Oil Sands Growth Update

Suncor's next major growth phase includes an expansion of existing upgrading facilities that targets an increase in production capacity to 350,000 bpd in 2008. Engineering on this portion of the project is substantially complete and construction is approximately 75% complete. The project remains on schedule and on budget. A targeted 50-day shutdown to Upgrader 2 to tie in new facilities related to the expansion is expected to begin on May 31. During the tie-in work, Upgrader 1 is expected to continue normal production.

Work underway also includes the expansion of Suncor's Firebag in-situ operations, with construction targeted for completion in 2007. The project, which is expected to increase the bitumen production capacity of Firebag Stages 1 and 2 by about 35%, also includes addition of cogeneration facilities. The cogeneration component of the project began commissioning and start-up in February 2007. Construction of the expansion component of the project was approximately 65% complete at the end of the first quarter.

Suncor's plans to increase production to 500,000 bpd to 550,000 bpd in 2010 to 2012, which were announced in 2001, involve a number of investments including increased bitumen production from mining and in-situ sources, additional facility infrastructure and a third oil sands upgrader. Plans are proceeding on schedule, with fabrication of major vessels for the planned upgrader underway.

In February 2007 Suncor filed a public disclosure document outlining our intent to apply for permission to develop our proposed Voyageur South mining and extraction project. If approved, construction could commence as early as 2009.

While approval of final cost estimates for portions of planned growth from 2008 through 2012 are still pending, Suncor capital spending plans of $5.3 billion for 2007 includes spending of approximately $2.5 billion this year on various components of the 500,000 bpd to 550,000 bpd expansion phase.

For an update on our significant growth projects currently in progress see page 11.

Oil Sands Crown Royalties and Cash Income Taxes

For a description of the Alberta Crown royalty regimes in effect for Suncor Oil Sands operations, see page 29 of our 2006 Annual Report.

In the first quarter of 2007, we recorded a pretax royalty estimate of $157 million ($110 million after tax) compared to $285 million ($182 million after tax) for the first quarter of 2006. We estimate 2007 annualized Crown royalties to be approximately $665 million ($465 million after tax) based on three months of actual results and the balance of the year estimated on 2007 forward crude pricing of US$63.14 per barrel as at March 31, 2007; current forecasts of production, capital and operating costs for the remainder of 2007; and a Cdn$/US$ exchange rate of $0.87. Accordingly, actual results may differ, and these differences may be material. Alberta Crown royalties payable in 2007 are highly sensitive to, among other factors, changes in crude oil and natural gas pricing, foreign exchange rates, the valuation of bitumen, and total capital and operating costs for each project.

The following table sets forth our estimates of royalties in the years 2008 through 2012, and certain assumptions on which we have based our estimates.

Anticipated Royalty Expense Based on Certain Assumptions

For the period from 2008-2012

WTI Price/bbl (US$)	**40**	**50**	**60**
Natural gas price per mcf at Henry Hub (US$)	6.75	8.25	10.00
Light/heavy oil differential of WTI at Cushing less Maya at the U.S. Gulf Coast (US$)	9.60	12.60	15.10
Cdn$/US$ exchange rate	0.80	0.85	0.90
Crown Royalty Expense (based on percentage of total Oil Sands revenue) (%)			
2008	8	10	12
2009-2012 (1)	4-5	5-7	6-8

(1) During 2006, we exercised our option to transition our base operations in 2009 to the generic bitumen-based royalty regime.

In 2007, we estimate we will incur cash taxes of approximately 70% to 100% of the expected 2007 provision for income tax expense. During the first quarter of 2007, Oil Sands recorded $143 million in current income expense reflecting this expectation. The increase in current income tax expense impacted cash flow from operations for all business segments, excluding our U.S. downstream operations presented in our Refining and Marketing segment.

We do not expect any significant cash tax in subsequent years until the next decade. In any particular year, our Oil Sands and Natural Gas operations may be subject to some cash income tax due to sensitivity to crude oil and natural gas commodity price volatility and the timing of recognition of capital expenditures for income tax purposes.

The forward-looking information in the preceding paragraphs and table under "Oil Sands Crown Royalties and Cash Income Taxes" incorporates operating and capital cost assumptions included in our current budget and long-range plan, and is not an estimate, forecast or prediction of actual events or circumstances.

As with the estimate of 2007 Alberta Crown royalties, anticipated royalty and cash taxes are highly sensitive to, among other factors, changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each oil sands project. In addition, all aspects of the current Alberta Oil Sands Crown royalty regime (including royalty rates, the royalty base and the value of bitumen for royalty purposes), and income tax legislation (including taxation rates), are subject to alteration by the government.

The Government of Alberta has undertaken a review of Crown royalties and other revenues paid to government by industry. This review is scheduled for completion in late 2007. For a more complete discussion, please see page 29 of our 2006 Annual Report.

The 2007 federal budget proposes to phase out the accelerated capital cost allowance that was originally intended to offset some of the risk associated with the large capital investment required to bring oil sands projects to production. The current accelerated capital cost allowance will continue to be available for assets acquired before 2011, and assets acquired before 2012 on projects where major construction commenced before March 19, 2007. We believe Suncor's Voyageur expansion phase, targeted for completion in 2012, will fall under the current accelerated capital cost allowance provisions.

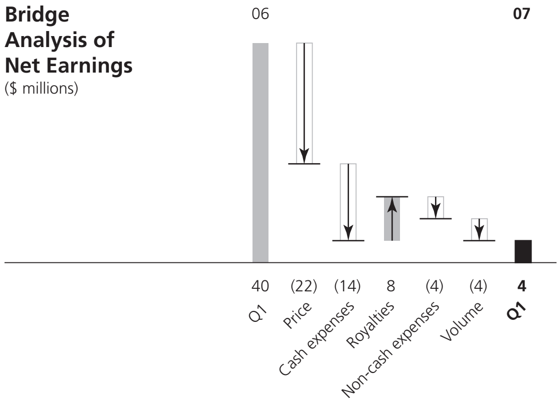
In light of proposed legislative changes, other uncertainties, and the potential for unanticipated events, we strongly caution it is impossible to accurately predict even a range of annualized royalty expense as a percentage of revenues or approximate cash tax, or the impact these royalties and cash taxes may have on our financial results. Differences may be material.

Natural Gas

Natural Gas recorded 2007 first quarter net earnings of $4 million, compared with $40 million during the first quarter of 2006. The decrease in net earnings was primarily as a result of lower price realizations. In addition, higher lifting costs, depreciation, depletion and amortization expense as a result of increased finding and development costs as well as higher dry hole exploration expenses negatively impacted earnings in the first quarter of 2007 compared to the first quarter of 2006. These negative impacts were partially offset by lower royalty expenses.

Cash flow from operations for the first quarter of 2007 was $64 million compared to $100 million from the first quarter of 2006. The decrease is due to the same factors affecting net earnings, excluding depreciation, depletion and amortization expense and dry hole costs.

Bridge Analysis of Net Earnings
($ millions)



Realized natural gas prices in the first quarter of 2007 were $7.01 per thousand cubic feet (mcf) compared to $9.03 per mcf in the first quarter of 2006, reflecting lower benchmark commodity prices.

Natural gas and liquids production in the first quarter of 2007 was 209 million cubic feet equivalent (mmcfe) per day, compared to 215 mmcfe per day in the first quarter of 2006. Our 2007 production outlook targets an average of 215 to 220 mmcfe per day for the year, offsetting Suncor's projected purchases for internal consumption at our oil sands and refining operations.

During the first quarter 2007, Suncor acquired developed and undeveloped lands in British Columbia for future development for approximately $160 million.

Refining & Marketing

Consistent with the company's organizational restructuring during the first quarter of 2007, results from our Canadian and U.S. downstream refining and marketing operations have been combined into a single business segment – Refining & Marketing. Comparative figures have been reclassified to reflect the combination of the previously disclosed Energy Marketing & Refining – Canada (EM&R) and Refining & Marketing – U.S.A. (R&M) segments. There was no impact to previously reported net earnings as a result of the combination. The results of company-wide energy marketing and trading activities will continue to be included in this segment. The financial results relating to the sales of Oil Sands and Natural Gas production will continue to be reported in their respective business segments.

Refining & Marketing recorded 2007 first quarter net earnings of $99 million, compared to net earnings of $11 million in the first quarter of 2006. Net earnings were higher as a result of:

- Stronger refining and retail margins in our downstream operations due to tighter supply of refined products in both the Ontario and U.S. Rocky Mountain markets.
- Increased sales volumes at our Commerce City refinery in the first quarter of 2007. Comparative first quarter 2006 sales volumes were significantly reduced due to a planned maintenance shutdown.

These positive impacts were partially offset by increased depreciation, depletion and amortization costs associated with the completion of major capital projects during 2006.

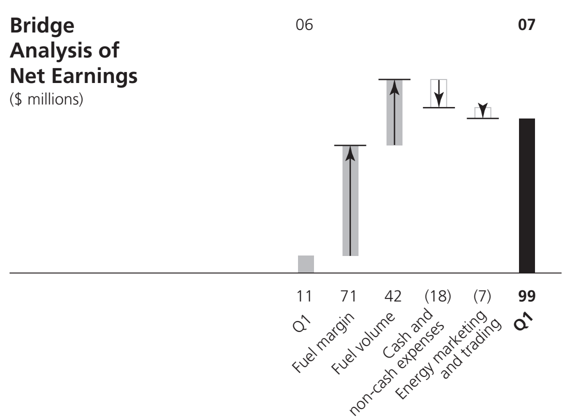
Energy marketing and trading activities, including physical and financial trading activities, resulted in a pretax net loss of $2 million in the first quarter of 2007, compared to an $8 million pretax gain in the first quarter of 2006.

Cash flow from operations was $171 million in the first quarter of 2007, compared to $51 million in the first quarter of 2006. This increase reflects the impact of the same factors affecting net earnings excluding depreciation, depletion and amortization expense.

During the first quarter of 2007, refinery utilization was 97%, compared to 74% in the first quarter of 2006. The lower utilization rate in the first quarter of 2006 was due to the planned maintenance shutdown at our Commerce City refinery.

Work continues on our oil sands integration project at our Sarnia, Ontario refinery. Original cost estimates have been revised upward to $960 million from the previous estimate of $800 million due to labour shortages and material supply issues. Suncor plans to begin a shutdown

Bridge Analysis of Net Earnings
($ millions)



of the Sarnia refinery in the third quarter of 2007 (with completion scheduled in the fourth quarter of 2007) to tie-in modified facilities that are expected to enable the facility to process up to 40,000 bpd of oil sands sour crude. Portions of the refinery will continue production during the shutdown period.

For an update on our significant growth projects currently in progress see page 11.

Corporate

During the first quarter of 2007, the company began allocating stock-based compensation expense from the Corporate segment to each of the reportable business segments. Comparative figures have been reclassified to reflect the allocation of stock-based compensation. There was no impact to consolidated net earnings as a result of the allocation.

Corporate recorded net expenses of $5 million in the first quarter of 2007, compared to net expenses of $45 million during the first quarter of 2006. After-tax unrealized foreign exchange gains on U.S. dollar denominated long-term debt were $12 million in the first quarter of 2007 compared to a loss of $1 million in the first quarter of 2006.

Net expenses decreased mainly due to the following:

- a reduction in stock-based compensation expense reflecting a decline in our share price during the first quarter of 2007 compared to an increase in the same period in 2006.
- higher costs incurred during the first quarter of 2006 relating to the implementation of our new Enterprise Resource Planning system.

Cash used in operations was $23 million in the first quarter of 2007 compared to $46 million in the first quarter of 2006. Cash used in operations is lower primarily due to the earnings factors described above.

Breakdown of Net Corporate Expense

Three months ended March 31 ($ millions)	**2007**	2006
Corporate expenses	**(3)**	(45)
Group eliminations	**(2)**	—
Total	**(5)**	(45)

Analysis of Financial Condition and Liquidity

Excluding cash and cash equivalents, short-term debt and future income taxes, Suncor had an operating working capital deficiency of $447 million at the end of the first quarter of 2007, compared to a surplus of $254 million at the end of the first quarter of 2006.

During the first three months of 2007, net debt increased to approximately $2.3 billion from $1.9 billion at December 31, 2006. The increase in net debt levels was primarily a result of capital spending on our growth program in the first quarter of 2007. In March 2007, Suncor issued $600 million of 5.39% Medium Term Notes under an outstanding $2 billion debt shelf prospectus. The proceeds were used to repay outstanding commercial paper borrowings.

At March 31, 2007 our undrawn lines of credit were approximately $1.8 billion. We believe we have the capital resources from our undrawn lines of credit, cash flow from operations, and access to debt capital markets, to fund the remainder of our 2007 capital spending program and to meet our current working capital requirements. If additional capital is required, we believe adequate additional financing will continue to be available at market terms and rates. We anticipate capital spending of approximately $5.3 billion for 2007.

Significant Capital Project Update

A summary of the progress on our significant projects under construction is provided below. All projects listed below have received Board of Directors approval.

Description	Cost Estimate (1) ($ millions)	Spent 2007 Year to date ($ millions)	Total spent to date ($ millions)	Status (1)
Oil Sands				
Coker unit	$2 100	$160	$1 750	Project is on schedule and on budget.
Millennium naphtha unit (2)	$650	$40	$125	Project is on schedule and on budget.
Steepbank extraction plant (3)	$880	$45	$110	Project is on schedule and on budget.
Firebag cogeneration and expansion	$400	$25	$340	Cogeneration component completed in Q1 2007. Full project is on schedule and on budget.
Refining and Marketing				
Diesel desulphurization and oil sands integration	$960	$35	$835	Diesel desulphurization component complete. Oil sands integration component is scheduled for completion in Q4 2007. (4)

(1) Estimating and budgeting for major capital projects is a process that involves uncertainties and that evolves in stages, each with progressively more refined data and a correspondingly narrower range of uncertainty. At very early stages, when broad engineering design specifications are developed, the level of uncertainty can result in price ranges with -30%/+50% (or similar) levels of uncertainty. As project engineering progresses, vendor bids are studied, goods and materials ordered and we move closer to the build stage, the level of uncertainty narrows. Generally, when projects receive final approval from our Board of Directors,our cost estimates have a range of uncertainty that has narrowed to the -10%/+10% or similar range. These ranges establish an expected high and low capital cost estimate for a project. When we say that a project is "on budget", we mean that we still expect the final project capital cost to fall within the current range of uncertainty for the project. Even at this stage, the uncertainties in the estimating process and the impact of future events, can and will cause actual results to differ, in some cases materially, from our estimates.

(2) The Millennium naphtha unit project is expected to enhance the product mix of our oil sands production.

(3) The Steepbank extraction plant will replace and enhance originally constructed extraction facilities.

(4) See page 9 for discussion.

The addition of a third upgrader has not received final approval by Suncor's Board of Directors. Suncor has not yet announced a firm capital cost estimate for this project as the cost estimates, together with the final configuration of the project, are still under development. However, preliminary cost figures included in Suncor's Voyageur regulatory approval application are under upward pressure. Initial engineering is expected in late 2007, at which time final approval to proceed with the project will be considered by Suncor's Board of Directors. Subject to final Board approval, the project will be included in the above table at that time.

To date approximately $900 million has been approved by the Board of Directors for preparatory work related to project design for the third upgrader, including engineering, site preparation and fabrication of some major vessels.

Suncor's Firebag Stage 3 project is expected to be submitted for final Board of Director's approval in the third quarter of 2007. To date approximately $550 million has been approved for planning and scoping initiatives related to project design.

Derivative Financial Instruments

Effective January 1, 2007, new accounting standards were implemented relating to financial instruments. For a more detailed discussion, see Change in Accounting Policies on page 13. These changes did not significantly impact earnings as a result of the adoption.

The company has hedged a portion of its forecasted Canadian and U.S. dollar denominated cash flows subject to U.S. dollar West Texas Intermediate (WTI) commodity price risk for 2007 and 2008. At March 31, 2007, costless collar crude oil hedges totaling 60,000 bpd of production were outstanding for the remainder of 2007 and 10,000 bpd for 2008. Prices for these barrels are fixed within a range from an average of US$51.64/bbl up to an average of US$101.06/bbl.

We intend to consider additional costless collars to a total of up to approximately 30% of our annual planned crude oil production if strategic opportunities are available.

We realized $2 million of hedging gains from our crude oil hedges in the first quarter of 2007 compared to no hedging gains for the comparable period in 2006.

The fair value of strategic derivative hedging instruments is the estimated amount, based on brokers' quotes and/or internal valuation models, the company would receive (pay) to terminate the contracts. In addition to our strategic hedging program, we also use derivative instruments to hedge risks specific to individual transactions. Such amounts, which also represent the unrecognized and unrecorded gain (loss), on the contracts, were as follows at March 31:

Fair Value of Hedging Derivative Financial Instruments

($ millions)	**2007**	2006
Revenue hedge swaps and collars	**6**	(22)
Interest rate and cross-currency interest rate swaps	**13**	13
Specific cash flow hedges of individual transactions	**2**	5
Total	**21**	(4)

Energy Marketing and Trading Activities

The net pretax earnings (loss) for the three months ended March 31, were as follows:

Net Pretax Earnings (Loss)

($ millions)	**2007**	2006
Physical energy contracts trading activity	**3**	10
Financial energy contracts trading activity	**(4)**	(1)
General and administrative costs	**(1)**	(1)
Total	**(2)**	8

The fair value of unsettled financial energy trading assets and liabilities at March 31, 2007 and December 31, 2006 were as follows:

Fair Value of Unsettled Financial Energy Trading Assets and Liabilities

($ millions)	**2007**	2006
Energy trading assets	**3**	16
Energy trading liabilities	**10**	13
Net trading assets (liabilities)	**(7)**	3

Environmental Regulation and Risk

On March 8, 2007 the Alberta government introduced the Climate Change and Emissions Management Amendment Act, which places intensity (emissions per unit of production) limits on facilities emitting more than 100,000 tonnes of CO_2 equivalent per year. Suncor's oil sands operations and several of our natural gas facilities would be included in this legislation. The Act calls for intensity reductions at these facilities of 12% by July 1, 2007 from an average 2003 to 2005 baseline.

The actual costs to Suncor will be dependent on a variety of factors that are not yet certain, including baseline calculation, facilities definition and potential offset credits.

The Canadian federal government is also considering greenhouse gas management legislation and regulation. At this time, no such legislation has been tabled and any potential impacts are unknown.

While there remains uncertainty around the outcome and impacts of climate change regulation, we continue to actively manage our emissions and to advance opportunities such as carbon capture and sequestration, and renewable energy development.

Control Environment

Based on their evaluation as of March 31, 2007, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures (as defined in Rules 13(a) – 15(e) and 15(d) – 15(e) under the United States Securities and Exchange Act of 1934 (the Exchange Act)) are effective to ensure that information required to be disclosed in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms. In addition, other than as described below, as of March 31, 2007, there were no changes in our internal control over financial reporting that occurred during the three month period ended March 31, 2007 that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting. We will continue to periodically evaluate our disclosure controls and procedures and internal control over financial reporting and will make any modifications from time to time as deemed necessary.

Change in Accounting Policies

On January 1, 2007 the company adopted CICA Handbook Section 3855 "Financial Instruments, Recognition and Measurement", Section 1530 "Comprehensive Income" and Section 3865 "Hedging". These sections establish the accounting and reporting standards for financial instruments and hedging activities and require the initial recognition of financial instruments at fair value on the balance sheet. The comparative interim consolidated financial statements have not been restated, except for the presentation of the cumulative foreign currency translation adjustment.

Transaction costs and the related cash flow impacts are included in the fair value assessments of each financial asset and financial liability instrument.

Generally, all derivatives, whether designated in hedging relationships or not, excluding those considered as normal purchases and normal sales, are required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Earnings. If the derivative is designated as a cash flow hedge each period, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income and are recognized in the Consolidated Statements of Earnings when the hedged item is recognized. Ineffective portions of changes in the fair value of hedging instruments are recognized in the Consolidated Statements of Earnings immediately for both fair value and cash flow hedges.

Gains or losses arising from hedging activities, including the ineffective portion, are reported in the same Consolidated Statement of Earnings caption as the hedged item. The determination of hedge effectiveness and the measurement of hedge ineffectiveness for cash flow hedges are based on internally derived valuations. The company uses these valuations to estimate the fair values of the underlying physical commodity contracts.

In addition to containing the effective portions of the gains/losses on our cash flow hedges, the accumulated other comprehensive income account also contains the cumulative foreign currency translation adjustment of our foreign operations.

Upon implementation and initial measurement under the new standards at January 1, 2007, the following adjustments were recorded to the balance sheet:

Financial assets	$42 million
Financial liabilities	$29 million
Retained earnings	$5 million
Accumulated other comprehensive loss	$63 million

The comparative interim consolidated financial statements have not been restated, except for presentation of the cumulative foreign currency translation adjustment of $71 million.

Non-GAAP Financial Measures

Certain financial measures referred to in this MD&A, namely cash flow from operations, return on capital employed (ROCE) and Oil Sands cash and total operating costs per barrel, are not prescribed by GAAP. These non-GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. Suncor includes these non-GAAP financial measures because investors may use this information to analyze operating performance, leverage and liquidity. The additional information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Suncor provides a detailed numerical reconciliation of ROCE on an annual basis in the company's annual MD&A, which is to be read in conjunction with the company's annual consolidated financial statements. For a summarized narrative reconciliation of ROCE calculated on a March 31, 2007 interim basis, please refer to page 29 of the first quarter 2007 Report to Shareholders.

Cash flow from operations is expressed before changes in non-cash working capital. A reconciliation of net earnings to cash flow from operations is provided in the Schedules of Segmented Data, which are an integral part of Suncor's March 31, 2007 unaudited interim consolidated financial statements.

A reconciliation of cash flow from operations on a per common share basis is presented in the following table:

For the three months ended March 31		**2007**	2006
Cash flow from operations ($ millions)	A	**790**	1 314
Weighted number of shares outstanding (millions of shares)	B	**460.1**	458.2
Cash flow from operations (per share)	(A / B)	**1.72**	2.87

The following tables outline the reconciliation of Oil Sands cash and total operating costs to expenses included in the Schedules of Segmented Data in the company's financial statements. Amounts included in the tables below for base operations and In-situ bitumen production reconcile to the schedules of segmented data when combined.

Oil Sands Operating Costs – Total Operations

		Quarter ended March 31			
		2007		2006	
(unaudited)		$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses		**612**		526	
Less: natural gas costs, stock-based compensation, and inventory changes		**(116)**		(125)	
Less: non-monetary transactions		**(32)**		(48)	
Accretion of asset retirement obligations		**10**		7	
Taxes other than income taxes		**12**		10	
Cash costs		**486**	**21.75**	370	15.55
Natural gas		**100**	**4.50**	82	3.45
Imported bitumen (net of other reported product purchases)		**1**	**0.05**	1	0.05
Total cash operating costs	A	**587**	**26.30**	453	19.05
In-situ (Firebag) start-up costs	B	**—**	**—**	21	0.90
Total cash operating costs after start-up costs	A+B	**587**	**26.30**	474	19.95
Depreciation, depletion and amortization		**100**	**4.45**	93	3.90
Total operating costs		**687**	**30.75**	567	23.85
Production (thousands of barrels per day)		**248.2**		264.4	

Oil Sands Operating Costs – In-situ Bitumen Production Only

(unaudited)	Quarter ended March 31 2007 $ millions	2007 $/barrel	2006 $ millions	2006 $/barrel
Operating, selling and general expenses	**69**		32	
Less: natural gas costs and inventory changes	**(35)**		(19)	
Taxes other than income taxes	**1**		1	
Cash costs	**35**	**11.05**	14	5.70
Natural gas	**35**	**11.05**	19	7.70
Cash operating costs	**70**	**22.10**	33	13.40
In-situ (Firebag) start-up costs	**—**	**—**	21	8.50
Total cash operating costs after start-up costs	**70**	**22.10**	54	21.90
Depreciation, depletion and amortization	**17**	**5.35**	17	6.90
Total operating costs	**87**	**27.45**	71	28.80
Production (thousands of barrels per day)	**35.3**		27.4	

Legal notice – forward-looking information

This management's discussion and analysis contains certain forward-looking statements that are based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of its experience and its perception of historical trends.

All statements that address expectations or projections about the future, including statements about Suncor's strategy for growth, expected and future expenditures, commodity prices, costs, schedules, production volumes, operating and financial results and expected impact of future commitments, are forward-looking statements. Some of the forward-looking statements may be identified by words like "expects," "anticipates," "estimates," "plans," "scheduled," "intends," "believes," "projects," "indicates," "could," "focus," "goal," "proposed," "target," "objective," "may," "outlook," "on our way," "investigating," "continue," and similar expressions. These statements are not guarantees of future performance and involve a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Suncor. Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements and readers are cautioned not to place undue reliance on them.

The risks, uncertainties and other factors that could influence actual results include but are not limited to changes in the general economic, market and business conditions; fluctuations in supply and demand for Suncor's products; commodity prices and currency exchange rates; Suncor's ability to respond to changing markets and to receive timely regulatory approvals; the successful and timely implementation of capital projects including growth projects (for example the Firebag in-situ development and Voyageur) and regulatory projects; the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering needed to reduce the margin of error and increase the level of accuracy; the integrity and reliability of Suncor's capital assets; the cumulative impact of other resource development; future environmental laws; the accuracy of Suncor's reserve, resource and future production estimates and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venture partners; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; uncertainties resulting from potential delays or changes in plans with respect to projects or capital expenditures; actions by governmental authorities including the imposition of taxes or changes to fees and royalties, changes in environmental and other regulations (for example, the Government of Alberta's current review of the Crown Royalty regime, and the Government of Canada's current review of greenhouse gas emission regulations); the ability and willingness of parties with whom we have material relationships to perform their obligations to us; and the occurrence of unexpected events such as blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor.

The foregoing important factors are not exhaustive. Many of these risk factors are discussed in further detail throughout this Management's Discussion and Analysis and in the company's Annual Information Form/Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission (SEC) at www.sec.gov. Readers are also referred to the risk factors described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

Consolidated statements of earnings

(unaudited)

($ millions)	Three months ended March 31 2007	2006
Revenues (note 4)	**3 951**	3 858
Expenses		
Purchases of crude oil and products	**1 138**	951
Operating, selling and general (notes 4 and 7)	**840**	772
Energy marketing and trading activities (note 4)	**571**	262
Transportation and other costs	**46**	51
Depreciation, depletion and amortization	**190**	158
Accretion of asset retirement obligations	**12**	8
Exploration	**32**	31
Royalties (note 10)	**189**	329
Taxes other than income taxes	**158**	140
Gain on disposal of assets	**—**	(4)
Project start-up costs	**3**	21
Financing expenses (note 5)	**(11)**	7
	3 168	2 726
Earnings Before Income Taxes	**783**	1 132
Provision for (Recovery of) Income Taxes		
Current	**162**	(1)
Future	**70**	420
	232	419
Net Earnings	**551**	713
Per Common Share (dollars), (note 6)		
Basic	**1.20**	1.56
Diluted	**1.17**	1.52
Cash dividends	**0.08**	0.06

See accompanying notes.

Consolidated balance sheets

(unaudited)

($ millions)	March 31 2007	December 31 2006 (restated) (note 2)
Assets		
Current assets		
Cash and cash equivalents	**468**	521
Accounts receivable (notes 2 and 4)	**1 194**	1 050
Inventories	**600**	589
Income taxes receivable	**—**	33
Future income taxes	**64**	109
Total current assets	**2 326**	2 302
Property, plant and equipment, net	**17 122**	16 189
Deferred charges and other (notes 2 and 4)	**306**	290
Total assets	**19 754**	18 781
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**6**	7
Accounts payable and accrued liabilities (notes 2, 4 and 10)	**2 082**	2 111
Taxes other than income taxes	**50**	40
Income taxes payable	**109**	—
Total current liabilities	**2 247**	2 158
Long-term debt	**2 740**	2 385
Accrued liabilities and other (notes 2 and 4)	**1 178**	1 214
Future income taxes (notes 2 and 4)	**4 100**	4 072
Shareholders' equity (see below)	**9 489**	8 952
Total liabilities and shareholders' equity	**19 754**	18 781

Shareholders' Equity

	Number (thousands)		Number (thousands)	
Share capital	**460 219**	**804**	459 944	794
Contributed surplus		**116**		100
Accumulated other comprehensive income (notes 2 and 4)		**(80)**		(71)
Retained earnings (note 2)		**8 649**		8 129
Total shareholders' equity		**9 489**		8 952

See accompanying notes.

Consolidated statements of cash flows

(unaudited)

($ millions)	Three months ended March 31 **2007**	2006
Operating Activities		
Cash flow from operations	**790**	1 314
Decrease (increase) in operating working capital		
Accounts receivable	**(139)**	(417)
Inventories	**(11)**	76
Accounts payable and accrued liabilities	**(87)**	(241)
Taxes payable	**152**	(16)
Cash flow from operating activities	**705**	716
Cash Used in Investing Activities	**(1 100)**	(657)
Net Cash Surplus (Deficiency) Before Financing Activities	**(395)**	59
Financing Activities		
Decrease in short-term debt	**(1)**	(20)
Proceeds from issuance of long-term debt	**601**	—
Net decrease in long-term debt	**(231)**	(94)
Issuance of common shares under stock option plan	**5**	22
Dividends paid on common shares	**(33)**	(25)
Deferred revenue	**3**	10
Cash provided by (used in) financing activities	**344**	(107)
Increase (Decrease) in Cash and Cash Equivalents	**(51)**	(48)
Effect of Foreign Exchange on Cash and Cash Equivalents	**(2)**	—
Cash and Cash Equivalents at Beginning of Period	**521**	165
Cash and Cash Equivalents at End of Period	**468**	117

See accompanying notes.

Consolidated statements of changes in shareholders' equity

(unaudited)

($ millions)	Share Capital	Contributed Surplus	Cumulative Foreign Currency Translation	Retained Earnings	Accumulated Other Comprehensive Income (AOCI)
At December 31, 2005, as previously reported	732	50	(81)	5 295	—
Retroactive adjustment for change in accounting policy (note 2)	—	—	81	—	(81)
At December 31, 2005, as restated	732	50	—	5 295	(81)
Net earnings	—	—	—	713	—
Dividends paid on common shares	—	—	—	(25)	—
Issued for cash under stock option plan	25	(3)	—	—	—
Issued under dividend reinvestment plan	2	—	—	(2)	—
Stock-based compensation expense	—	9	—	—	—
Change in AOCI related to foreign currency translation	—	—	—	—	3
At March 31, 2006	759	56	—	5 981	(78)
At December 31, 2006, as previously reported	794	100	(71)	8 129	—
Retroactive adjustment for change in accounting policy (note 2)	—	—	71	—	(71)
At December 31, 2006, as restated	794	100	—	8 129	(71)
Net earnings	**—**	**—**	**—**	**551**	**—**
Dividends paid on common shares	**—**	**—**	**—**	**(33)**	**—**
Issued for cash under stock option plan	**7**	**(2)**	**—**	**—**	**—**
Issued under dividend reinvestment plan	**3**	**—**	**—**	**(3)**	**—**
Stock-based compensation expense	**—**	**18**	**—**	**—**	**—**
Adjustment to opening retained earnings arising from ineffective portion of cash flow hedges at January 1, 2007	**—**	**—**	**—**	**5**	**—**
Adjustment to opening AOCI arising from effective portion of cash flow hedges at January 1, 2007	**—**	**—**	**—**	**—**	**8**
Change in AOCI related to foreign currency translation	**—**	**—**	**—**	**—**	**(13)**
Change in AOCI related to derivative hedging activities	**—**	**—**	**—**	**—**	**(4)**
At March 31, 2007	**804**	**116**	**—**	**8 649**	**(80)**

See accompanying notes.

Schedules of segmented data

(unaudited)

Three months ended March 31

($ millions)	Oil Sands 2007	Oil Sands 2006	Natural Gas 2007	Natural Gas 2006	Refining and Marketing (note 3) 2007	Refining and Marketing (note 3) 2006	Corporate and Eliminations 2007	Corporate and Eliminations 2006	Total 2007	Total 2006
EARNINGS										
Revenues										
Operating revenues	**1 443**	1 550	**144**	174	**1 786**	1 478	**2**	1	**3 375**	3 203
Energy marketing and trading activities	**—**	—	**—**	—	**571**	274	**(1)**	(5)	**570**	269
Net insurance proceeds	**—**	385	**—**	—	**—**	—	**—**	—	**—**	385
Intersegment revenues	**151**	185	**—**	6	**—**	—	**(151)**	(191)	**—**	—
Interest	**—**	—	**—**	—	**3**	—	**3**	1	**6**	1
	1 594	2 120	**144**	180	**2 360**	1 752	**(147)**	(194)	**3 951**	3 858
Expenses										
Purchases of crude oil and products	**9**	3	**—**	—	**1 279**	1 141	**(150)**	(193)	**1 138**	951
Operating, selling and general (note 3)	**612**	526	**38**	26	**175**	174	**15**	46	**840**	772
Energy marketing and trading activities	**—**	—	**—**	—	**573**	266	**(2)**	(4)	**571**	262
Transportation and other costs	**32**	37	**7**	6	**7**	8	**—**	—	**46**	51
Depreciation, depletion and amortization	**100**	93	**41**	34	**39**	24	**10**	7	**190**	158
Accretion of asset retirement obligations	**10**	7	**2**	1	**—**	—	**—**	—	**12**	8
Exploration	**13**	22	**19**	9	**—**	—	**—**	—	**32**	31
Royalties (note 10)	**157**	285	**32**	44	**—**	—	**—**	—	**189**	329
Taxes other than income taxes	**21**	21	**—**	—	**137**	119	**—**	—	**158**	140
Gain on disposal of assets	**—**	—	**—**	(4)	**—**	—	**—**	—	**—**	(4)
Project start-up costs	**2**	21	**—**	—	**1**	—	**—**	—	**3**	21
Financing expenses	**—**	—	**—**	—	**—**	—	**(11)**	7	**(11)**	7
	956	1 015	**139**	116	**2 211**	1 732	**(138)**	(137)	**3 168**	2 726
Earnings (loss) before income taxes	**638**	1 105	**5**	64	**149**	20	**(9)**	(57)	**783**	1 132
Income taxes	**(185)**	(398)	**(1)**	(24)	**(50)**	(9)	**4**	12	**(232)**	(419)
Net earnings (loss)	**453**	707	**4**	40	**99**	11	**(5)**	(45)	**551**	713
As at March 31										
TOTAL ASSETS	**14 365**	12 096	**1 716**	1 367	**4 040**	3 352	**(367)**	(734)	**19 754**	16 081

Schedules of segmented data (continued)

(unaudited)

	Oil Sands		Natural Gas		Refining and Marketing (note 3)		Corporate and Eliminations		Total	
Three months ended March 31										
($ millions)	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006
CASH FLOW BEFORE FINANCING ACTIVITIES										
Cash flow from (used in) operating activities:										
Cash flow from (used in) operations										
Net earnings (loss)	**453**	707	**4**	40	**99**	11	**(5)**	(45)	**551**	713
Exploration expenses	**—**	—	**15**	5	**—**	—	**—**	—	**15**	5
Non-cash items included in earnings										
Depreciation, depletion and amortization	**100**	93	**41**	34	**39**	24	**10**	7	**190**	158
Future income taxes	**42**	398	**—**	24	**27**	9	**1**	(11)	**70**	420
Gain on disposal of assets	**—**	—	**—**	(4)	**—**	—	**—**	—	**—**	(4)
Stock-based compensation expense	**8**	4	**1**	1	**5**	2	**4**	2	**18**	9
Other	**(20)**	12	**3**	—	**2**	8	**(33)**	1	**(48)**	21
Increase (decrease) in deferred credits and other	**(5)**	(5)	**—**	—	**(1)**	(3)	**—**	—	**(6)**	(8)
Total cash flow from (used in) operations	**578**	1 209	**64**	100	**171**	51	**(23)**	(46)	**790**	1 314
Decrease (increase) in operating working capital	**13**	(200)	**13**	18	**(36)**	(63)	**(75)**	(353)	**(85)**	(598)
Total cash flow from (used in) operating activities	**591**	1 009	**77**	118	**135**	(12)	**(98)**	(399)	**705**	716
Cash from (used in) investing activities:										
Capital and exploration expenditures	**(793)**	(407)	**(275)**	(115)	**(57)**	(226)	**(6)**	(4)	**(1 131)**	(752)
Deferred maintenance shutdown expenditures	**—**	—	**(1)**	—	**(1)**	(42)	**—**	—	**(2)**	(42)
Deferred outlays and other investments	**—**	—	**—**	—	**—**	—	**(1)**	(2)	**(1)**	(2)
Proceeds from disposals	**—**	—	**—**	13	**—**	—	**—**	—	**—**	13
Decrease (increase) in investing working capital	**73**	117	**—**	—	**(39)**	9	**—**	—	**34**	126
Total cash (used in) investing activities	**(720)**	(290)	**(276)**	(102)	**(97)**	(259)	**(7)**	(6)	**(1 100)**	(657)
Net cash surplus (deficiency) before financing activities	**(129)**	719	**(199)**	16	**38**	(271)	**(105)**	(405)	**(395)**	59

Notes to the consolidated financial statements

(unaudited)

1. ACCOUNTING POLICIES

These interim consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and follow the same accounting policies and methods of computation as, and should be read in conjunction with, the most recent annual financial statements, except for the accounting policy changes as described in note 2, Changes in Accounting Policies and note 3, Change in Segmented Disclosures.

In the opinion of management, these interim consolidated financial statements contain all adjustments of a normal and recurring nature necessary to present fairly Suncor Energy Inc.'s (Suncor) financial position at March 31, 2007 and the results of its operations and cash flows for the three month periods ended March 31, 2007 and 2006.

Certain prior period comparative figures have been reclassified to conform to the current period presentation.

2. CHANGES IN ACCOUNTING POLICIES

Financial Instruments

On January 1, 2007 the company adopted CICA Handbook Section 3855 "Financial Instruments, Recognition and Measurement", Section 1530 "Comprehensive Income" and Section 3865 "Hedging". These sections establish the accounting and reporting standards for financial instruments and hedging activities, and require the initial recognition of financial instruments at fair value on the balance sheet. The comparative interim consolidated financial statements have not been restated, except for the presentation of the cumulative foreign currency translation adjustment.

Transaction costs and the related cash flow impacts are included in the fair value assessments of each financial asset and financial liability instrument.

Generally, all derivatives, whether designated in hedging relationships or not, excluding those considered as normal purchases and normal sales, are required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge each period, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Earnings. If the derivative is designated as a cash flow hedge each period, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income and are recognized in the Consolidated Statements of Earnings when the hedged item is recognized. Ineffective portions of changes in the fair value of hedging instruments are recognized in the Consolidated Statements of Earnings immediately for both fair value and cash flow hedges.

Gains or losses arising from hedging activities, including the ineffective portion, are reported in the same Consolidated Statement of Earnings caption as the hedged item. The determination of hedge effectiveness and the measurement of hedge ineffectiveness for cash flow hedges are based on internally derived valuations. The company uses these valuations to estimate the fair values of the underlying physical commodity contracts.

In addition to containing the effective portions of the gains/losses on our cash flow hedges, the accumulated other comprehensive income account will also contain the cumulative foreign currency translation adjustment of our foreign operations.

Upon implementation and initial measurement under the new standards at January 1, 2007, the following adjustments were recorded to the balance sheet:

Financial Assets	$42 million
Financial Liabilities	$29 million
Retained Earnings	$5 million
Accumulated Other Comprehensive Loss	$63 million

The comparative interim consolidated financial statements have not been restated, except for the presentation of the cumulative foreign currency translation adjustment of $71 million.

Additional disclosure requirements for financial instruments have been approved by the CICA, and will be required disclosure for the company beginning January 1, 2008.

See Note 4 for a summary of financial instrument disclosures at March 31, 2007.

3. CHANGE IN SEGMENTED DISCLOSURES

Consistent with the company's organizational restructuring during the first quarter of 2007, results from our Canadian and U.S. downstream refining and marketing operations have been combined into a single business segment – Refining & Marketing. Comparative figures have been reclassified to reflect the combination of the previously disclosed Energy Marketing & Refining – Canada (EM&R) and Refining & Marketing – U.S.A. (R&M) segments. The results of company-wide energy marketing and trading activities will continue to be included in this segment. The financial results relating to the sales of Oil Sands and Natural Gas production will continue to be reported in their respective business segments. There was no impact to consolidated net earnings as a result of the restructuring.

Effective January 1, 2007, the company began allocating stock-based compensation expense to each of the reportable business segments. Comparative figures have been reclassified to reflect the allocation of stock-based compensation. There was no impact to consolidated net earnings as a result of the allocation.

4. FINANCIAL INSTRUMENTS

Balance Sheet Financial Instruments

The company's financial instruments recognized in the Consolidated Balance Sheet consist of cash and cash equivalents, accounts receivable, derivative contracts, substantially all current liabilities (except for the current portions of asset retirement and pension obligations), and long-term debt. Unless otherwise noted, carrying values reflect the current fair value of the company's financial instruments.

The estimated fair values of recognized financial instruments have been determined based on the company's assessment of available market information and appropriate valuation methodologies, or through comparisons to similar debt instruments; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The company's fixed-term debt is accounted for under the amortized cost method. Upon initial recognition, the cost of the debt is its fair value, adjusted for any associated transaction costs. We do not recognize gains or losses arising from changes in the fair value of this debt until the gains or losses are realized. At March 31, 2007, the carrying value of our fixed-term debt was $2.4 billion (fair value – $2.6 billion).

Hedges

Fair Value Hedges

The company periodically enters into derivative financial instrument contracts such as interest rate swaps as part of its risk management strategy to minimize exposure to changes in cash flows of interest-bearing debt. At March 31, 2007, the company had interest rate derivatives classified as fair value hedges outstanding for up to five years relating to fixed rate debt.

There was no ineffectiveness recognized on derivative contracts designated as fair value hedges during the three month period ended March 31, 2007.

Cash Flow Hedges

Suncor operates in a global industry where the market price of its produced petroleum and natural gas products is determined based on floating benchmark indices denominated in U.S. dollars. The company periodically enters into derivative financial instrument contracts such as forwards, futures, swaps, options and costless collars to hedge against the potential adverse impact of changing market prices due to changes in the underlying indices. Specifically, the company manages crude sales price variability by entering into West Texas Intermediate (WTI) derivative transactions. The company also manages variability in market interest rates during periods of debt issuance through the use of interest rate swap transactions.

At March 31, 2007, the company had hedged a portion of its forecasted Canadian and U.S. dollar denominated cash flows subject to U.S. dollar WTI commodity risk for 2007 and 2008, as well as cash flows related to natural gas production and refinery operations in 2007 and 2008, and a portion of its Euro currency exposure created by the anticipated purchase of equipment payable in Euros in 2007.

The earnings impact associated with realized and unrealized hedge ineffectiveness on derivative contracts designated as cash flow hedges during the three month period ended March 31, 2007 was a gain of $2 million.

For the three month period ended March 31, 2007, assets increased by $20 million and liabilities increased by $9 million as a result of recording derivative instruments at fair value in accordance with the new standards.

The fair value of hedging derivative financial instruments as recorded, is the estimated amount, based on broker quotes and/or internal valuation models, that the company would receive (pay) to terminate the contracts. Such amounts were as follows:

($ millions)	**March 31 2007**	December 31 2006
Revenue hedge swaps and collars	**6**	22
Interest rate and cross-currency interest rate swaps	**13**	16
Specific cash flow hedges of individual transactions	**2**	(4)
Fair value of outstanding hedging derivative financial instruments	**21**	34

Accumulated Other Comprehensive Income (OCI)

A reconciliation of changes in accumulated OCI attributable to derivative hedging activities for the three month period ending March 31, 2007 is as follows:

($ millions)	**2007**
OCI attributable to derivatives and hedging activities, recorded upon initial adoption, net of income taxes of $5	**8**
Current period net changes arising from cash flow hedges, net of income taxes of $5	**(5)**
Net unrealized hedging gains at the beginning of the period reclassified to earnings during the period, net of income taxes of $1	**1**
OCI attributable to derivatives and hedging activities, end of period, net of income taxes of $1	**4**

Energy Marketing and Trading Activities

In addition to the financial derivatives used for hedging activities, the company uses physical and financial energy contracts, including swaps, forwards and options, to earn trading and marketing revenues. These energy trading activities are accounted for using the mark-to-market method and, as such, all financial instruments are recorded at fair value at each balance sheet date. Physical energy marketing contracts involve activities intended to enhance prices and satisfy physical deliveries to customers. The results of these activities are reported as revenue and as energy trading and marketing expenses in the Consolidated Statements of Earnings. The net pretax earnings (loss) for the three month period ended March 31 were as follows:

Net Pretax Earnings (Loss)

($ millions)	Three months ended March 31 **2007**	2006
Physical energy contracts trading activity	**3**	10
Financial energy contracts trading activity	**(4)**	(1)
General and administrative costs	**(1)**	(1)
Total	**(2)**	8

The fair value of unsettled (unrealized) financial energy trading assets and liabilities are as follows:

($ millions)	**March 31 2007**	December 31 2006
Energy trading assets	**3**	16
Energy trading liabilities	**10**	13
Net energy trading assets (liabilities)	**(7)**	3

Change in Fair Value of Net Assets

($ millions)	2007
Fair value of contracts outstanding at December 31, 2006	3
Fair value of contracts realized during the period	**(6)**
Fair value of contracts entered into during the period	**(5)**
Changes in values attributable to market price and other market changes	**1**
Fair value of contracts outstanding at March 31, 2007	**(7)**

The source of the valuations of the above contracts is based on actively quoted prices and/or internal model valuations.

5. FINANCING EXPENSES

	Three months ended March 31	
($ millions)	**2007**	2006
Interest on debt	**38**	39
Capitalized interest	**(38)**	(33)
Net interest expense	**—**	6
Foreign exchange loss (gain) on long-term debt	**(12)**	1
Other foreign exchange gain	**1**	—
Total financing expenses (income)	**(11)**	7

6. RECONCILIATION OF BASIC AND DILUTED EARNINGS PER COMMON SHARE

	Three months ended March 31	
($ millions)	**2007**	2006
Net earnings	**551**	713
(millions of common shares)		
Weighted-average number of common shares	**460**	458
Dilutive securities:		
Options issued under stock-based compensation plans	**11**	12
Weighted-average number of diluted common shares	**471**	470
(dollars per common share)		
Basic earnings per share [(a)]	**1.20**	1.56
Diluted earnings per share [(b)]	**1.17**	1.52

Note: An option will have a dilutive effect under the treasury stock method only when the average market price of the common stock during the period exceeds the exercise price of the option.

(a) Basic earnings per share is net earnings divided by the weighted-average number of common shares.

(b) Diluted earnings per share is net earnings, divided by the weighted-average number of diluted common shares.

7. STOCK-BASED COMPENSATION

A common share option gives the holder the right, but not the obligation, to purchase common shares at a predetermined price over a specified period of time.

After the date of grant, employees that hold options must earn the right to exercise them. This is done by the employee fulfilling a time requirement for service to the company, and with respect to certain options, is subject to accelerated vesting should the company meet predetermined performance criteria. Once this right has been earned, these options are considered vested.

The predetermined price at which an option can be exercised is equal to or greater than the market price of the common shares on the date the option is granted.

A performance vesting share unit is an award entitling employees to receive cash to varying degrees contingent upon Suncor's shareholder return relative to a peer group of companies.

(a) Stock Option Plans

Under the SunShare long-term incentive plan, the company granted 312,000 options to new employees in the first quarter of 2007 (260,000 options granted during the first quarter of 2006).

On April 30, 2008, 50% of the outstanding, unvested SunShare options will vest. The remaining 50% of the outstanding, unvested SunShare options may vest on April 30, 2008 if the final predetermined performance criterion is met. If the performance criteria is not met, the unvested options that have not previously expired or been cancelled, will automatically vest on January 1, 2012. Management believes that it is highly likely the final performance criterion will be met and that all unvested SunShare options at April 30, 2008 will therefore vest. Stock-based compensation expense has been recorded to reflect this assumption.

Under the company's other plans, 1,615,000 options were granted in the first quarter of 2007 (1,509,000 options granted during the first quarter of 2006).

The fair values of all common share options granted during the period are estimated as at the grant date using the Black-Scholes option-pricing model. The weighted-average fair values of the options granted during the various periods and the weighted-average assumptions used in their determination are as noted below:

	Three months ended March 31	
	2007	2006
Quarterly dividend per share	**$0.08**	$0.06
Risk-free interest rate	**4.08%**	4.08%
Expected life	**6 years**	6 years
Expected volatility	**28%**	29%
Weighted-average fair value per option	**$28.85**	$32.30

Stock-based compensation expense recognized in the first quarter of 2007 related to stock options plans was $18 million (2006 – $9 million).

Common share options granted prior to January 1, 2003 are not recognized as compensation expense in the Consolidated Statements of Earnings. The company's reported net earnings attributable to common shareholders and earnings per share prepared in accordance with the fair value method of accounting for stock-based compensation would have been reduced for all common share options granted prior to 2003 to the pro forma amounts stated below:

	Three months ended March 31	
($ millions, except per share amounts)	**2007**	2006
Net earnings – as reported	**551**	713
Less: compensation cost under the fair value method for pre-2003 options	**3**	2
Pro forma net earnings	**548**	711
Basic earnings per share		
As reported	**1.20**	1.56
Pro forma	**1.19**	1.55
Diluted earnings per share		
As reported	**1.17**	1.52
Pro forma	**1.16**	1.51

(b) Performance Share Units (PSUs)

In the first quarter of 2007 the company issued 399,000 (2006 – 390,000) PSUs. Expense recognized in the first quarter of 2007 was $19 million (2006 – $24 million).

8. EMPLOYEE FUTURE BENEFITS LIABILITY

The company's pension plans and other post-retirement benefits programs are described in note 8 of the company's 2006 Annual Report. The following is the status of the net periodic benefit cost for the three months ended March 31.

	Pension Benefits		Other Post-retirement Benefits	
	2007	2006	**2007**	2006
Current service costs	**13**	11	**1**	1
Interest costs	**11**	10	**2**	2
Expected return on plan assets	**(11)**	(8)	**—**	—
Amortization of net actuarial loss	**6**	7	**—**	—
Net periodic benefit cost	**19**	20	**3**	3

9. SUPPLEMENTAL INFORMATION

	Three months ended March 31	
($ millions)	**2007**	2006
Interest paid	**55**	53
Income taxes paid	**17**	11

Revenue Hedges

Strategic Crude Oil at March 31, 2007

	Quantity (bpd)	Average Price (US$/bbl) [a]	Revenue Hedged (Cdn$ millions) [b]	Hedge Period [c]
Costless collars	60 000	51.64 – 93.26	982 – 1 774	2007
Costless collars	10 000	59.85 – 101.06	253 – 426	2008

Natural Gas at March 31, 2007

	Quantity (GJ/day)	Average Price (Cdn$/GJ)	Revenue Hedged (Cdn$ millions)	Hedge Period [c]
Swaps	4 000	6.11	7	2007
Costless collars	10 000	7.00 – 7.90	6 – 7	2007 [d]
Costless collars	5 000	7.00 – 8.05	7 – 9	2007 [e]
Costless collars	5 000	7.25 – 8.92	8 – 10	2007 [f]

Foreign Currency Hedges at March 31, 2007

	Notional (Euro millions)	Average Forward Rate	Dollars Hedged (Cdn$ millions)	Hedge Period [c]
Euro/Cdn forwards	21	1.41	29	2007 [g]

(a) Average price for crude oil costless collars is US$ WTI per barrel at Cushing, Oklahoma.
(b) The revenue and margin hedged is translated to Cdn$ at the March 31, 2007 exchange rate and is subject to change as the Cdn$/US$ exchange rate fluctuates during the hedge period.
(c) Original hedge term is for the full year unless otherwise noted.
(d) For the period August to October 2007, inclusive.
(e) For the period April to October 2007, inclusive.
(f) For the period April to October 2007, inclusive.
(g) Settlements for applicable forwards occurring within the period April to September 2007.

10. ROYALTY ESTIMATE MEASUREMENT UNCERTAINTY

Alberta Crown royalties in effect for each Oil Sands project require payments to the Government of Alberta based on annual gross revenues less related transportation costs (R) less allowable costs (C), including the deduction of certain capital expenditures (the 25% R-C royalty), subject to a minimum payment of 1% of R.

Oil Sands royalties payable in 2007 are highly sensitive to, among other factors, changes in crude oil and natural gas pricing, foreign exchange rates and total capital and operating costs for each project. Oil Sands pretax royalty estimate was $157 million ($110 million after tax) for the first three months of 2007 compared to $285 million ($182 million after tax) for the first three months of 2006. We estimate 2007 annualized Crown Royalties to be approximately $665 million ($465 million after tax) based on three months of actual results together with 2007 forward crude oil pricing of US$63.14 per barrel as at March 31, 2007; current forecasts of production, capital and operating costs for the remainder of 2007; and a Canadian/US foreign exchange rate of $0.87. Accordingly, actual results will differ, and these differences may be material. The balance of the consolidated royalty expense is in respect of natural gas royalties of $32 million ($26 million after tax).

11. LONG-TERM DEBT AND CREDIT FACILITIES

On March 5, 2007, the company repaid maturing 6.80% $250 million Medium Term Notes. The company used commercial paper to repay the notes.

On March 26, 2007, the company issued 5.39% Medium Term Notes with a principal amount of $600 million, under an outstanding $2 billion debt shelf prospectus. These notes bear interest, which is paid semi-annually, and mature on March 26, 2037. The net proceeds received were used to repay commercial paper.

At March 31, 2007, undrawn lines of credit were approximately $1,767 million, as follows:

($ millions)	
Facility that is fully revolving for 364 days, has a term period of one year and expires in 2008	300
Facility that is fully revolving for a period of five years and expires in 2011	2 000
Facilities that can be terminated at any time at the option of the lenders	30
Total available credit facilities	2 330
Credit facilities supporting outstanding commercial paper and standby letters of credit	563
Total undrawn credit facilities	1 767

As at March 31, 2007, the company had issued $265 million in letters of credit to various third parties and had outstanding commercial paper of $298 million.

Highlights

(unaudited)

	2007	2006
Cash Flow from Operations		
(dollars per common share – basic)		
For the three months ended March 31		
Cash flow from operations (1)	**1.72**	2.87
Ratios		
For the twelve months ended March 31		
Return on capital employed (%) (2)	**35.1**	28.5
Return on capital employed (%) (3)	**26.5**	21.0
Net debt to cash flow from operations (times) (4)	**0.6**	0.8
Interest coverage on long-term debt (times)		
Net earnings (5)	**23.3**	18.4
Cash flow from operations (6)	**28.2**	22.5
As at March 31		
Debt to debt plus shareholders' equity (%) (7)	**22.51**	30.46
Common Share Information		
As at March 31		
Share price at end of trading		
Toronto Stock Exchange – Cdn$	**87.85**	89.63
New York Stock Exchange – US$	**76.35**	77.02
Common share options outstanding (thousands)	**21 389**	19 809
For the three months ended March 31		
Average number outstanding, weighted monthly (thousands)	**460 074**	458 230

Refer to the Quarterly Operating Summary for a discussion of financial measures not prepared in accordance with generally accepted accounting principles (GAAP).

(1) Cash flow from operations for the period; divided by the weighted average number of common shares outstanding during the period.

(2) For the twelve month period ended; net earnings (2007 – $2,821 million; 2006 – $1,787 million) adjusted for after-tax financing expenses (2007 – income of $12 million; 2006 – income of $17 million) divided by average capital employed (2007 – $8,040 million; 2006 – $6,279 million). Average capital employed is the sum of shareholders' equity and short-term debt plus long-term debt less cash and cash equivalents, at the beginning and end of the year, divided by two, less capitalized costs related to major projects in progress (as applicable). Return on capital employed (ROCE) for Suncor operating segments as presented in the Quarterly Operating Summary is calculated in a manner consistent with consolidated ROCE. For a detailed reconciliation of ROCE prepared on an annual basis, see page 58 of Suncor's 2006 Annual Report to Shareholders.

(3) If capital employed were to include capitalized costs related to major projects in progress (average capital employed including major projects in progress: 2007 – $10,660 million; 2006 – $8,510 million), the return on capital employed would be as stated on this line.

(4) Short-term debt plus long-term debt less cash and cash equivalents, divided by cash flow from operations for the twelve month period then ended.

(5) Net earnings plus income taxes and interest expense, divided by the sum of interest expense and capitalized interest.

(6) Cash flow from operations plus current income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

(7) Short-term debt plus long-term debt; divided by the sum of short-term debt, long-term debt and shareholders' equity.

Quarterly operating summary

(unaudited)

	For the quarter ended					Total year
	Mar 31 2007	Dec 31 2006	Sept 30 2006	June 30 2006	Mar 31 2006	Dec 31 2006
OIL SANDS						
Production (1),(a)						
Total production	**248.2**	266.4	242.8	267.3	264.4	260.0
Firebag	**35.3**	35.1	37.2	35.0	27.4	33.7
Sales (a)						
Light sweet crude oil	**105.5**	113.7	84.9	124.7	119.2	110.5
Diesel	**29.5**	24.0	20.7	32.9	35.1	28.2
Light sour crude oil	**112.7**	126.8	125.8	99.2	121.0	118.2
Bitumen	**6.8**	9.7	6.6	8.5	—	6.2
Total sales	**254.5**	274.2	238.0	265.3	275.3	263.1
Average sales price (2),(b)						
Light sweet crude oil	**68.63**	64.51	78.11	78.27	69.00	71.98
Other (diesel, light sour crude oil and bitumen)	**63.62**	57.91	68.60	72.75	63.28	65.17
Total	**65.70**	60.65	71.99	75.34	65.75	68.03
Total *	**65.61**	60.65	71.99	75.34	65.75	68.03
Cash operating costs and Total operating costs – Total operations						
Cash costs	**21.75**	22.65	21.00	15.65	15.55	18.70
Natural gas	**4.50**	3.00	2.60	2.55	3.45	2.90
Imported bitumen	**0.05**	—	0.10	0.10	0.05	0.10
Cash operating costs (3),(c)	**26.30**	25.65	23.70	18.30	19.05	21.70
Firebag start-up costs	**—**	—	—	—	0.90	0.20
Total cash operating costs (4),(c)	**26.30**	25.65	23.70	18.30	19.95	21.90
Depreciation, depletion and amortization	**4.45**	4.25	4.30	3.80	3.90	4.05
Total operating costs (5),(c)	**30.75**	29.90	28.00	22.10	23.85	25.95
Cash operating costs and Total operating costs – In-situ bitumen production only						
Cash costs	**11.05**	8.05	5.55	8.50	5.70	8.95
Natural gas	**11.05**	9.90	7.60	8.15	7.70	8.35
Cash operating costs (6),(c)	**22.10**	17.95	13.15	16.65	13.40	17.30
Firebag start-up costs	**—**	—	—	—	8.50	1.70
Total cash operating costs (7),(c)	**22.10**	17.95	13.15	16.65	21.90	19.00
Depreciation, depletion and amortization	**5.35**	6.20	5.55	3.75	6.90	5.55
Total operating costs (8),(c)	**27.45**	24.15	18.70	20.40	28.80	24.55
(for the period ended)						
Capital employed (i)	**5 134**	5 015	5 491	5 486	5 401	
(for the twelve months ended)						
Return on capital employed (j)	**47.6**	53.5	57.7	53.6	35.1	
Return on capital employed (j)****	**34.7**	40.1	43.6	40.2	25.9	

Quarterly operating summary (continued)

(unaudited)

	For the quarter ended					Total year
	Mar 31 2007	Dec 31 2006	Sept 30 2006	June 30 2006	Mar 31 2006	Dec 31 2006
NATURAL GAS						
Gross production **						
Natural gas (d)	**191**	192	191	189	196	191
Natural gas liquids (a)	**2.4**	2.1	2.1	2.6	2.4	2.3
Crude oil (a)	**0.7**	0.5	0.7	0.9	0.8	0.7
Total gross production (e)	**34.9**	34.7	34.6	35.1	35.9	34.8
Total gross production (f)	**209**	208	208	211	215	209
Average sales price (2)						
Natural gas (g)	**7.01**	6.55	6.33	6.38	9.03	7.15
Natural gas (g)*	**7.14**	6.40	6.13	6.22	8.75	6.95
Natural gas liquids (b)	**54.12**	44.20	53.11	60.14	51.75	44.96
Crude oil – Conventional (b)	**65.49**	51.20	84.95	74.18	60.30	74.83
Net wells drilled						
Conventional – Exploratory ***	**4**	4	1	1	5	11
– Development	**8**	6	6	2	4	18
	12	10	7	3	9	29
(for the period ended)						
Capital employed (i)	**1 063**	857	775	767	587	
(for the twelve months ended)						
Return on capital employed (j)	**8.5**	14.9	27.7	30.4	31.4	
REFINING AND MARKETING						
Refined product sales (h)						
Transportation fuels						
Gasoline						
Retail	**5.4**	5.5	5.3	5.3	5.1	5.3
Other	**11.8**	11.0	11.4	11.9	8.9	10.6
Distillate	**10.3**	8.8	8.5	9.0	7.9	8.5
Total transportation fuel sales	**27.5**	25.3	25.2	26.2	21.9	24.4
Petrochemicals	**0.8**	0.4	1.0	0.9	1.2	0.9
Asphalt	**1.3**	0.8	1.6	1.3	1.0	1.2
Other	**2.0**	2.6	3.6	3.2	2.5	3.0
Total refined product sales	**31.6**	29.1	31.4	31.6	26.6	29.5
Crude oil supply and refining						
Processed at refineries (h)	**24.6**	19.4	24.2	24.5	18.8	21.7
Utilization of refining capacity (j)	**97**	76	95	96	74	85
(for the period ended)						
Capital employed (i)	**1 928**	1 818	1 629	804	854	
(for the twelve months ended)						
Return on capital employed (j)	**22.7**	20.4	30.1	32.0	21.8	
Return on capital employed (j)****	**15.6**	12.5	16.5	16.3	12.4	

Quarterly operating summary (continued)

Non-GAAP Financial Measures

Certain financial measures referred to in the Highlights and Quarterly Operating Summary are not prescribed by Canadian generally accepted accounting principles (GAAP). Suncor includes cash flow from operations, return on capital employed and cash and total operating costs per barrel data because investors may use this information to analyze operating performance, leverage and liquidity. The additional information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Definitions

(1) Total operations production	– Total operations production includes total production from both mining and in-situ operations.
(2) Average sales price	– This operating statistic is calculated before royalties and net of related transportation costs (including or excluding the impact of hedging activities as noted).
(3) Cash operating costs – Total operations	– Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense, taxes other than income taxes and the cost of bitumen imported from third parties. Per barrel amounts are based on total production volumes. For a reconciliation of this non GAAP financial measure see Management's Discussion and Analysis.
(4) Total cash operating costs – Total operations	– Include cash operating costs – Total operations as defined above and cash start-up costs for in-situ operations. Per barrel amounts are based on total production volumes.
(5) Total operating costs – Total operations	– Include total cash operating costs – Total operations as defined above and non-cash operating costs. Per barrel amounts are based on total production volumes.
(6) Cash operating costs – In-situ bitumen production	– Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense and taxes other than income taxes. Per barrel amounts are based on in-situ production volumes only.
(7) Total cash operating costs – In-situ bitumen production	– Include cash operating costs – In-situ bitumen production as defined above and cash start-up operating costs. Per barrel amounts are based on in-situ production volumes only.
(8) Total operating costs – In-situ bitumen production	– Include total cash operating costs – In-situ bitumen production as defined above and non-cash operating costs. Per barrel amounts are based on in-situ production volumes only.

Explanatory Notes

* Excludes the impact of hedging activities.

** Currently Natural Gas production is located in the Western Canada Sedimentary Basin.

*** Excludes exploratory wells in progress.

**** If capital employed were to include capitalized costs related to major projects in progress, the return on capital employed would be as stated on this line.

(a) thousands of barrels per day
(b) dollars per barrel
(c) dollars per barrel rounded to the nearest $0.05
(d) millions of cubic feet per day
(e) thousands of barrels of oil equivalent per day
(f) millions of cubic feet equivalent per day
(g) dollars per thousand cubic feet
(h) thousands of cubic metres per day
(i) $ millions
(j) percentage

Metric conversion

Crude oil, refined products, etc. 1m^3 (cubic metre) = approx. 6.29 barrels