third quarter 2006

Report to shareholders for the period ended September 30, 2006

> growing strategically

Higher crude oil prices drive solid earnings for Suncor Energy

All financial figures are unaudited and in Canadian dollars unless noted otherwise. Certain prior period amounts have been restated to conform to the current year's presentation. Certain financial measures referred to in this document are not prescribed by Canadian generally accepted accounting principles (GAAP). For a description of these measures, see "Non-GAAP Financial Measures" in Suncor's 2006 third 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 third quarter 2006 net earnings of $682 million ($1.48 per common share), compared to $315 million ($0.69 per common share) in the third quarter of 2005. There was no unrealized foreign exchange adjustment in the third quarter of 2006. Excluding the effects of unrealized foreign exchange gains on the company's U.S. dollar denominated long-term debt in the third quarter of 2005, net earnings were $262 million ($0.57 per common share). Cash flow from operations was $1.153 billion in the third quarter of 2006, compared to $651 million in the third quarter of 2005.

Earnings by Quarter
($ millions)

2006 Q3	2005 Q3	2006 YTD	2005 YTD
682	315	**2 613**	465

Cash Flow from Operations by Quarter
($ millions)

2006 Q3	2005 Q3	2006 YTD	2005 YTD
1 153	651	**3 787**	1 250

Production
(thousands of barrels of oil equivalent per day)

	2006 Q3	2005 Q3	2006 YTD	2005 YTD
Natural Gas	**34.6**	36.3	**35.2**	34.8
Oil Sands	**242.8**	148.2	**258.1**	138.8
Total	**277.4**	184.5	**293.3**	173.6

Ratios
(per cent)
for the twelve months ended September 30

	2006	2005
Return on average shareholder's equity	**47.7**	16.0
Return on capital employed	**47.1**	12.6

"We are well positioned for a strong finish to the year and expect improved reliability going into 2007." **Rick George** president and chief executive officer

The increase in net earnings was primarily due to higher oil sands production, stronger commodity prices and higher refining margins in U.S. downstream operations. These positive impacts were partially offset by the stronger Canadian dollar and higher total oil sands operating costs as a result of increased production. The same factors impacted cash flow from operations.

Net earnings for the first nine months of 2006 were $2.613 billion ($5.69 per common share), compared to $465 million ($1.02 per common share) for the same period in 2005. Excluding the impacts of insurance proceeds, income tax revaluations and unrealized foreign exchange gains, net earnings for the first nine months of 2006 were $1.946 billion compared to $235 million in the same period of 2005. Cash flow from operations for the first nine months of 2006 was $3.787 billion, compared to $1.250 billion in the first nine months of 2005.

Suncor's total upstream production averaged 277,400 barrels of oil equivalent (boe) per day during the third quarter of 2006, compared to 184,500 boe per day in the third quarter of 2005. Natural gas production in the third quarter of 2006 was 191 million cubic feet (mmcf) per day, compared to third quarter 2005 production of 200 mmcf per day. Oil sands production during the third quarter of 2006 averaged 242,800 barrels per day (bpd), consisting of 236,200 bpd of synthetic crude oil and 6,600 bpd of bitumen, which was sold directly to the market. Third quarter oil sands production was lower than full capacity due to unplanned maintenance. Comparative production during the third quarter of 2005, which was reduced due to damage from a fire earlier in the year, averaged 148,200 bpd, including 23,000 bpd of bitumen.

Subsequent to the end of the quarter, in early October, additional maintenance was required in Suncor's upgrading operations. With the combined impact of these operational issues, Suncor has revised its annual average oil sands production target to 255,000 to 260,000 bpd of synthetic crude oil.

"Our capital investment projects are continuing forward on schedule," said Rick George, president and chief executive officer. "We are well positioned for a strong finish to the year and expect improved reliability going into 2007."

Oil sands cash operating costs for the third quarter of 2006 averaged $23.70 per barrel, compared to $27.65 per barrel during the third quarter of 2005. The decrease in cash operating costs per barrel is due to operating expenses being spread over significantly more barrels of production. This was partially offset by increased insurance expense and lower than capacity production in the third quarter of 2006.

As a result of increased insurance premiums and lower production volumes, Suncor has revised its full year outlook for 2006 cash operating costs per barrel upward to a range of $20.50 to $21.00.

In Suncor's Canadian downstream operations, lower refining margins and refinery utilization were offset by higher trading gains resulting in consistent earnings quarter over quarter. Utilization decreased in the third quarter of 2006 due to planned maintenance and facility modifications that began in early September which are expected to conclude in November.

Earnings increased in the company's U.S. downstream operations due to higher refining margins and consistent refinery utilization compared to the third quarter of 2005.

GROWTH UPDATE

Suncor's growth plans target oil sands production of 500,000 to 550,000 bpd in the 2010 to 2012 timeframe. The next major milestone in the company's plans is an increase in oil sands production capacity to 350,000 bpd in 2008. The centrepiece of this expansion is the addition of a third pair of cokers to Upgrader 2. Engineering on this portion of the project is nearing completion and construction is approximately 65% complete. This project is on schedule and on budget.

"In 2008, we expect to see a 35% increase in daily oil production," said George. "That's an important step on the way to our longer term goal of half a million barrels per day."

Work under way also includes the expansion of Suncor's 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, includes the addition of cogeneration facilities. This project is also on schedule and on budget, with construction approximately 25% complete for the expansion project and approximately 80% complete for the cogeneration project. As Suncor continues to develop its in-situ operations, management expects to seek final Board of Directors' approval for Firebag Stage 3 in 2007.

In July 2006, a regulatory hearing was held on Suncor's planned third upgrader and Steepbank Mine extension.

Decisions on these project applications are expected at the end of the year. The company expects to advance project development plans and cost estimates to a level appropriate to seek Board approval in 2007. Pending regulatory and final Board approval, Suncor plans to begin site preparation for both projects in 2007.

In Suncor's Canadian downstream operations, work continues on the second phase of a planned upgrade to the company's Sarnia refinery. As planned, phase two of the project will continue into 2007. However, labour shortages and material supply issues have put upward cost pressures on the overall project. As a result, the $800 million cost estimate for both phases of the project will likely increase. When completed in 2007, modifications are expected to increase the refinery's capacity to process sour crude oil from Suncor's oil sands operations.

As Suncor invests for future growth, prudent debt management remains a priority. Net debt was reduced to $1.8 billion at the end of the third quarter of 2006, compared with $2.9 billion at December 31, 2005.

OUTLOOK FOR 2006

Suncor's outlook provides management's targets for 2006 in certain key areas of the company's business. Production and financial targets have been revised. See the notes to this table and Suncor's third quarter 2006 management's discussion and analysis for further details.

	Nine months ended September 30, 2006	2006 full year outlook
Oil Sands		
Production (bpd) (1)	**252 800**	255 000 – 260 000
Diesel	**11%**	11%
Sweet	**43%**	45%
Sour	**46%**	44%
Realization on crude sales basket (2)	**WTI @ Cushing less Cdn$6.29 per barrel**	WTI @ Cushing less Cdn$6.00 – $7.00 per barrel
Cash operating costs (3)	**$20.25 per barrel**	$20.50 – $21.00 per barrel
Natural Gas (4)		
Natural gas production (mmcf/d)	**192**	195 to 200

(1) The 255,000 to 260,000 bpd production outlook target consists entirely of synthetic crude oil barrels. Suncor-produced bitumen may be sold directly to the market depending on certain market or operational conditions. In addition to the average production of 252,800 bpd of synthetic crude oil during the first nine months of 2006, 5,300 bpd of bitumen was sold directly to the market. The original estimate for 2006 was 260,000 bpd.

(2) Suncor has reduced its original target for realizations on its crude oil sales basket from WTI less Cdn$5.50 to $6.50 to WTI less Cdn$6.00 to $7.00. The lower realization reflects the impact of lower than expected market prices for sweet synthetic crude oil in the fourth quarter of 2006.

(3) Effective January 1, 2006, cash operating costs per barrel, before commissioning and start-up costs, reflect a change in accounting policy to expense overburden costs as incurred (see page 13 of Suncor's third quarter 2006 MD&A). The change in accounting policy for overburden resulted in non-cash costs being reclassified to cash costs. However, total operating costs are not significantly impacted. All comparative balances have been retroactively restated for these changes in all 2006 Reports to Shareholders.

Cash operating costs are sensitive to natural gas prices. The estimate of $20.50 to $21.00 per barrel assumes a natural gas price of US$6.75 per thousand cubic feet (mcf) at Henry Hub. The original estimate for 2006 was $18.75 to $19.50 per barrel. Cash operating costs per barrel are not prescribed by 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" in Suncor's 2006 third quarter MD&A.

(4) Suncor has reduced its original natural gas production target of 205 to 210 mmcf/d due to shut-in production as a result of pipeline and processing facility constraints.

For a discussion of risks and uncertainties that may affect our financial performance, see pages 33 to 40 in our Annual Information Form, dated March 1, 2006.

MANAGEMENT'S DISCUSSION AND ANALYSIS

October 25, 2006

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 September 30, 2006 unaudited interim consolidated financial statements and notes. Readers should also refer to our MD&A on pages 17 to 58 of our 2005 Annual Report and to our Annual Information Form, dated March 1, 2006. All financial information is reported in Canadian dollars 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 56 of our 2005 Annual Report, and page 14 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. Any reference to "year-to-date" or "YTD" means the nine month period ended September 30.

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 Annual Information Form 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 12.

SELECTED FINANCIAL INFORMATION

Industry Indicators	3 months ended September 30		9 months ended September 30	
(average for the period)	**2006**	2005	**2006**	2005
West Texas Intermediate (WTI) crude oil US$/barrel at Cushing	**70.50**	63.20	**68.20**	55.40
Canadian 0.3% par crude oil Cdn$/barrel at Edmonton	**79.40**	76.40	**75.60**	68.30
Light/heavy crude oil differential US$/barrel				
WTI at Cushing less Lloyd Blend at Hardisty	**17.25**	19.20	**21.40**	19.90
Natural Gas US$/mcf at Henry Hub	**6.55**	8.25	**7.45**	7.10
Natural Gas (Alberta spot) Cdn$/mcf at AECO	**6.05**	8.15	**7.20**	7.40
New York Harbour 3-2-1 crack (1) US$/barrel	**10.20**	14.45	**10.65**	9.60
Exchange rate: Cdn$:US$	**0.89**	0.84	**0.89**	0.82

(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 the New York Harbour distillate margin and dividing by three.

Outstanding Share Data (as at September 30, 2006)	
Common shares	**459 595 964**
Common share options – total	**19 783 179**
Common share options – exercisable (1)	**8 934 086**

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

Summary of Quarterly Results

($ millions, except per share data)	2006 quarter ended Sept. 30	Jun. 30	Mar. 31	2005 quarter ended Dec. 31	Sept. 30	Jun. 30	Mar. 31	2004 quarter ended Dec. 31
Revenues	**4 114**	4 070	3 858	3 521	3 149	2 385	2 074	2 333
Net earnings	**682**	1 218	713	693	315	83	67	326
Net earnings attributable to common shareholders per share								
Basic	**1.48**	2.65	1.56	1.52	0.69	0.18	0.15	0.72
Diluted	**1.45**	2.59	1.52	1.48	0.67	0.18	0.14	0.71

ANALYSIS OF CONSOLIDATED STATEMENTS OF EARNINGS AND CASH FLOWS

Net earnings for the third quarter of 2006 were $682 million, compared to $315 million for the third quarter of 2005. The increase in net earnings was primarily due to:

- an increase in Oil Sands crude oil production following recovery work to repair portions of the plant damaged in a January 2005 fire and the subsequent expansion of synthetic crude oil production capacity to 260,000 barrels per day (bpd) in October 2005. While production in the third quarter of 2006 was higher than the third quarter of 2005, it was below capacity due to unplanned maintenance.
- an increase in the average price realization for Oil Sands crude oil to $71.99 per barrel in the third quarter of 2006 from $56.01 per barrel during the third quarter of 2005.
- higher refining margins in our U.S. downstream operations.
- a reduction in stock-based compensation expense, primarily reflecting the decline in our share price.

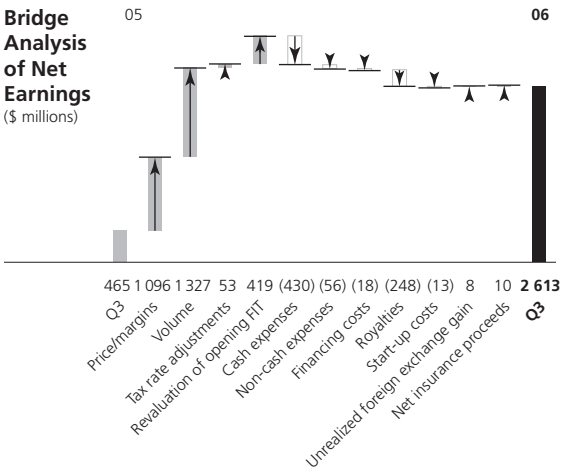
These positive net earnings impacts were partially offset by higher insurance premiums assessed during the third quarter of 2006 (see page 6), lower earnings in our Natural Gas business due primarily to lower price realizations, and the absence of fire insurance receipts during the third quarter of 2006 (compared to $105 million after-tax insurance proceeds received during the third quarter of 2005).

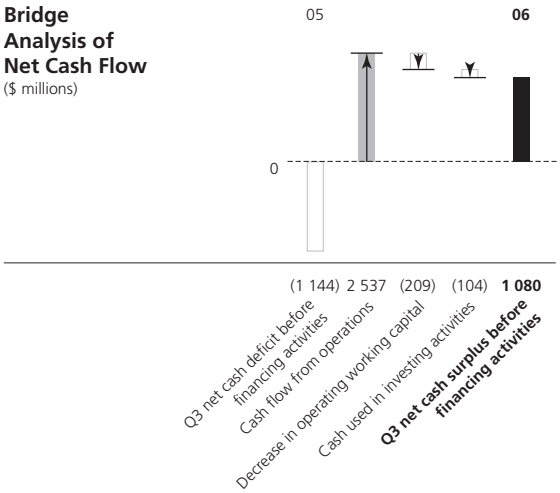
Cash flow from operations in the third quarter of 2006 was $1,153 million, compared to $651 million in the same period of 2005. Cash flow from operations was higher due primarily to the same factors that impacted net earnings.

Net earnings for the first nine months of 2006 were $2,613 million compared to $465 million in the same period of 2005. In addition to the factors listed above, the increase in net earnings was also due to reductions in the federal and Alberta income tax rates during the second quarter of 2006.

Cash flow from operations for the first nine months of 2006 was $3,787 million, compared to $1,250 million in the first nine months of 2005. Excluding the impact of the income tax rate reductions, the increase was primarily due to the same factors that impacted net earnings for the first nine months of 2006.

Excluding the revaluation impact of the federal and Alberta tax rate reductions on opening future taxes, our effective tax rate for the first nine months of 2006 was 33%, compared to 39% in the first nine months of 2005. The year-to-date effective tax rate is consistent with our full year expectations. The higher effective tax rate in 2005 was due to proportionately lower Oil Sands earnings relative to consolidated earnings. As a result, earnings subject to a higher effective tax rate (our Natural Gas business unit), and the large corporations tax (which was a capital tax insensitive to earnings), had a greater impact on the overall effective tax rate.





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 that are presented in our unaudited interim consolidated financial statements and notes in accordance with Canadian GAAP.

	3 months ended September 30 (Q3)		9 months ended September 30	
($ millions, after tax)	**2006**	2005	**2006**	2005
Net earnings before the following items	**682**	157	**1 959**	235
Firebag Stage 2 start-up costs	**—**	—	**(13)**	—
Oil Sands fire accrued insurance proceeds (1)	**—**	105	**205**	195
Impact of income tax rate reductions on opening future income tax liabilities (2)	**—**	—	**419**	—
Unrealized foreign exchange gains on U.S. dollar denominated long-term debt	**—**	53	**43**	35
Net earnings as reported	**682**	315	**2 613**	465

(1) Accrued business interruption proceeds net of income taxes and Alberta Crown Royalties. For discussion see page 8.

(2) Impacts of the Federal and Alberta income tax rate changes enacted in the second quarter of 2006.

ANALYSIS OF SEGMENTED EARNINGS AND CASH FLOW

Oil Sands

Oil Sands recorded 2006 third quarter net earnings of $583 million, compared with $225 million in the third quarter of 2005. Net earnings were higher primarily as a result of:

- the increase in production and sales volumes following completion in September 2005 of recovery work to repair portions of the facilities damaged in a January 2005 fire and the subsequent expansion of crude oil production capacity to 260,000 bpd in October 2005.
- an increase in the average price realization for Oil Sands crude products. The price increase reflects an 11.5% increase in average benchmark WTI crude oil prices, and the absence of crude oil hedging losses in the third quarter of 2006 (see "Derivative Financial Instruments" on page 12), compared to a $102 million after-tax loss in the third quarter of 2005.

These positive impacts were partially offset by operational issues and unplanned maintenance during the third quarter of 2006 that resulted in production volumes below plant capacity, and a decrease of higher value diesel fuel and sweet crude products in our sales mix. In addition, the 6% strengthening of the Canadian dollar compared to the U.S. dollar reduced net earnings. Because our crude oil is sold based on U.S. dollar benchmark prices, the stronger Canadian dollar reduces the realized value of Suncor's products.

Purchases of crude oil and products were $71 million in the third quarter of 2006 compared to $8 million in the third quarter of 2005. The increase was due to the purchase of additional finished products to meet plant and customer demands during unplanned maintenance that occurred during the third quarter of 2006.

Operating expenses before tax were $510 million in the third quarter of 2006 compared to $353 million in the third quarter of 2005. The increase in operating costs was primarily due to the following factors:

- higher total production levels.
- higher contract mining costs in order to manage the impact of the worldwide heavy vehicle tire shortage.
- higher costs associated with unplanned maintenance.
- a change in accounting policy for non-monetary transactions (see page 13) whereby certain natural gas costs and offsetting revenues of $25 million were recorded in the third quarter of 2006.
- higher insurance premium expense in Oil Sands resulting from:

  i) additional premium expenses related to losses incurred by one of our business interruption insurers as a result of claims stemming from losses in the Gulf of Mexico during the summer of 2005 (see page 11)

  ii) insurance premiums paid to a newly formed self-insurance entity, all of which are fully offset in the corporate segment, and do not impact consolidated results (see page 11)

Transportation and other costs were $41 million in the third quarter of 2006 compared to $23 million in the third quarter of 2005. The increase in transportation costs was due primarily to increased volumes shipped out of the Fort McMurray area.

Depreciation, depletion and amortization expense was $96 million in the third quarter of 2006 compared to $83 million during the same period in 2005. The increase was due primarily to the inclusion of newly commissioned upgrading facilities and Firebag Stage 2 operations in our depreciable cost base during the fourth quarter of 2005 and first quarter of 2006, respectively.

Alberta Crown royalty expense was $119 million in the third quarter of 2006 compared to $136 million in the third quarter of 2005. The decrease was due mainly to the year-to-date adjustment of estimated royalty expense as a result of the lower forward curve for crude commodity prices for the balance of the year, partially offset by the net impact of higher sales volumes. See page 8 for a discussion of Alberta Oil Sands Crown royalties.

Cash flow from operations was $926 million in the third quarter of 2006, compared to $441 million in the third quarter of 2005. Excluding the impact of depreciation, depletion and amortization, the decrease was primarily due to the same factors that impacted net earnings.

Net earnings for the nine months ended September 30, 2006 were $2,412 million, compared to $393 million for the nine months ended September 30, 2005. This increase is due to the same factors that impacted the third quarter 2006 net earnings, as well as federal and Alberta income tax rate reductions enacted in the second quarter of 2006 that resulted in a $419 million increase to net earnings.

Cash flow from operations for the first nine months of 2006 was $3,234 million compared to $899 million in the first nine months of 2005. The increase was primarily due to the same factors that impacted net earnings, excluding the impact of depreciation, depletion and amortization, and the revaluation of future tax balances resulting from the reduction of federal and Alberta income tax rates.

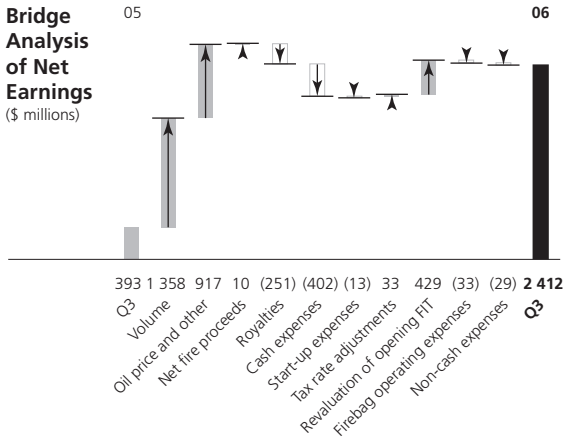
Oil Sands production during the third quarter of 2006 averaged 242,800 barrels per day (bpd), consisting of 236,200 bpd of synthetic crude oil and 6,600 bpd of bitumen, which was sold directly to the market. Third quarter oil sands production was lower than full capacity due to unplanned maintenance. Comparative production during the third quarter of 2005, which was reduced due to damage from a fire earlier in the year, averaged 148,200 bpd, including 23,000 bpd of bitumen.

Subsequent to the end of the quarter, in early October, additional maintenance was required. With the combined impact of these maintenance issues, Suncor has revised our annual oil sands production target for 2006. The original target of 260,000 bpd of synthetic crude oil has been revised to 255,000 to 260,000 bpd of synthetic crude oil.

Sales during the third quarter averaged 238,000 bpd, compared with 144,500 bpd during the third quarter of 2005. The proportion of higher value diesel fuel and sweet crude products decreased to 44% of the total sales in the third quarter of 2006, compared to 56% in the third quarter of 2005, due to operational limitations and unplanned maintenance. Sales prices averaged $71.99 per barrel during the third quarter of 2006 compared to $56.01 per barrel in the third quarter of 2005.

Effective January 1, 2006, cash operating costs per barrel, before commissioning and start-up costs, reflect a change in accounting policy to expense overburden costs as incurred (see page 13), as well as the inclusion of research and development costs. The change in accounting policy for overburden resulted in higher cash costs and lower non-cash costs. Therefore, recorded cash operating costs per barrel have increased, but total operating costs were not significantly impacted by this accounting change. Commencing in the first quarter of 2006, cash operating costs per barrel now reflect total Oil Sands operations including mining and in-situ production costs. In the past, operating costs per barrel for base (mining and upgrading) operations and in-situ operations were disclosed separately. All comparative balances have been retroactively restated for these changes in all 2006 Reports to Shareholders.

During the third quarter, cash operating costs averaged $23.70 per barrel, compared to $27.65 per barrel during



the third quarter of 2005. The decrease in cash operating costs per barrel is due to our cash operating expenses being applied to significantly more barrels of production. However, cash operating costs during the third quarter of 2006 were higher than our original full year outlook of $18.75 to $19.50, due mainly to increased insurance premiums and lower than capacity production volumes. As a result, we have revised our full year outlook for 2006 cash operating costs per barrel upward to $20.50 to $21.00. Refer to page 14 for further details on cash operating costs as a non-GAAP financial measure, including the calculation and reconciliation to GAAP measures.

We have also revised our original target for the price realization on our Oil Sands crude sales basket outlook downward from Cdn$5.50 to Cdn$6.50 below WTI to Cdn$6.00 to Cdn$7.00 below WTI. The lower price realization reflects the impact of lower than expected market prices for sweet synthetic crude.

Oil Sands Fire Insurance Update

There were no additional insurance proceeds received during the third quarter of 2006. Final settlement of our business interruption policy was received in the second quarter of 2006 and only our property loss policy claim remains outstanding. Final settlement of this claim is anticipated early in 2007. To date we have received $148 million (US$125 million) in proceeds from our property loss insurers.

Oil Sands Growth Update

Suncor's growth plans target oil sands production of 500,000 to 550,000 bpd in the 2010 to 2012 timeframe. The next major milestone in the company's plans is an increase in oil sands production capacity to 350,000 bpd in 2008. The centrepiece of this expansion is the addition of a third pair of cokers to Upgrader 2. Engineering on this portion of the project is nearing completion and construction is approximately 65% complete. This project is on schedule and on budget.

Work under way also includes the expansion of Suncor's 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, also includes the addition of cogeneration facilities. This project is also on schedule and on budget, with construction approximately 25% complete for the expansion project and approximately 80% complete for the cogeneration project. As Suncor continues to develop its in-situ operations, we expect to seek Board of Directors' approval for Firebag Stage 3 in 2007.

In July 2006, a regulatory hearing was held on Suncor's planned third upgrader and Steepbank Mine extension. A decision on the project application is expected before the end of the year. The company expects to advance project development plans and cost estimates to a level appropriate to seek Board of Directors' approval in 2007. Pending regulatory and Board approval, Suncor plans to begin construction of both projects in 2007.

For an update on our significant growth projects currently in progress see page 12.

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 27 of our 2005 Annual Report.

In the third quarter of 2006 we recorded a pretax royalty estimate of $119 million ($81 million after tax) compared to $136 million ($88 million after tax) for the third quarter of 2005. We estimate 2006 annualized Crown Royalties to be approximately $880 million ($600 million after tax), compared to $406 million ($259 million after tax) paid in 2005. The 2006 estimate is based on:

- nine months of actual results including the final $385 million in business interruption insurance proceeds
- the balance of the year estimate on 2006 forward average crude oil pricing of US$64.36 as at September 30, 2006
- current production, capital and operating cost estimates for the remainder of 2006
- a Canadian/US foreign exchange rate of $0.89, and
- no further receipts of property loss insurance proceeds other than those recorded to date.

Because our 2006 annualized Crown royalties estimates are based on these and other assumptions, our actual royalties may be materially different. Our Alberta Crown royalties payable in 2006 are highly sensitive to, among other factors, changes in crude oil and natural gas pricing, timing of the receipt of property damage insurance proceeds, 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 expense in the years 2006 through 2012, and certain assumptions on which we have based our estimates.

ANTICIPATED ROYALTY EXPENSE BASED ON CERTAIN ASSUMPTIONS

(For the period from 2006 – 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) (%)			
2006 – 08	8 – 10	10 – 12	12 – 14
2009 – 12 (1)	5 – 7	6 – 8	6 – 8

(1) Assuming we exercise our option to transition our base operations in 2009 to the generic bitumen-based royalty regime.

For 2007, we estimate we will have partial cash taxes in the range of 70-100% of expected effective tax rates, based on current prices, current forecasts of production, capital and operating costs for the remainder of 2006 and 2007 and no further receipts of property loss insurance proceeds other than those recorded to date. Any cash tax in 2007 would be due in February 2008. We do not expect any significant cash tax in subsequent years until some time in 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.

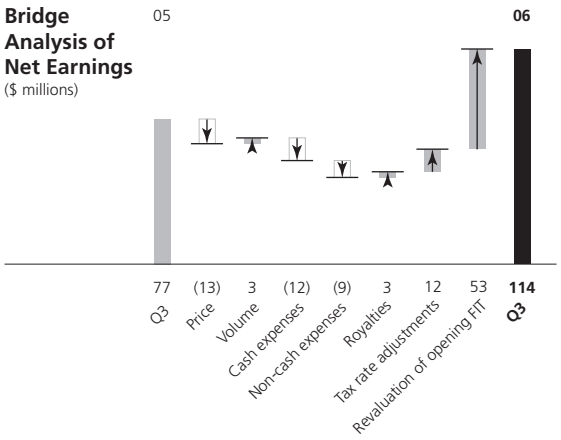
As with the estimate of 2006 Oil Sands royalties, anticipated royalty and cash taxes are highly sensitive to, among other factors, changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs (for each oil sands project in the case of Alberta Crown royalties). In addition, all aspects of the current Alberta oil sands royalty regime, including royalty rates and the royalty base, including the value of bitumen, and the income tax legislation, including taxation rates, are subject to alteration and interpretation by the government. In light of these uncertainties and the potential for unanticipated events to occur, we strongly caution that 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. Actual differences may be material.

Natural Gas

Natural Gas recorded 2006 third quarter net earnings of $12 million, compared with $24 million during the third quarter of 2005. The decrease in net earnings was primarily as a result of lower price realizations partially offset by lower dry hole costs and lower royalties. Realized natural gas prices in the third quarter of 2006 were $6.33 per thousand cubic feet (mcf) compared to $8.32 per mcf in the third quarter of 2005, reflecting lower benchmark commodity prices.

Cash flow from operations for the third quarter of 2006 was $68 million compared to $104 million from the third quarter of 2005. The decrease is due to the same factors affecting net earnings, excluding dry hole costs and depreciation, depletion and amortization expenses.

Year-to-date net earnings were $114 million, compared to $77 million in the first nine months of 2005. The increase in year-to-date earnings resulted primarily from the reduction in the federal and Alberta income tax rates enacted in the second quarter of 2006. Excluding the tax adjustment, net earnings were $61 million for the first nine months of 2006 compared to $77 million for the same period in 2005. The decrease in 2006 compared to 2005 resulted from higher seismic expenses and dry hole costs, higher operating costs and higher depreciation, depletion and amortization costs. Realized natural gas prices and production volumes year-to-date were in line with those in 2005.



Cash flow from operations for the first nine months of 2006 was $233 million, compared to $268 million for the first nine months of 2005, reflecting the same factors that affected net earnings excluding dry hole costs and depreciation, depletion and amortization expenses and the revaluation of future tax balances resulting from the reduction of federal and Alberta income tax rates.

Natural gas production in the third quarter of 2006 was 191 million cubic feet (mmcf) per day, compared to 200 mmcf per day in the third quarter of 2005. Our 2006 production outlook targets have been adjusted to an average of 195 to 200 mmcf per day for the year, from the originally disclosed estimates of 205 to 210 mmcf per day, due to shut-in production as a result of pipeline and processing facility constraints.

Energy Marketing & Refining – Canada (EM&R)

EM&R recorded 2006 third quarter net earnings of $17 million, unchanged from the third quarter of 2005. Higher physical trading profits were offset by lower refining margins and lower refinery utilization as a result of a major planned maintenance shutdown beginning in September 2006. Higher depreciation, depletion and amortization costs associated with the completion of capital projects, was fully offset by a reduction in operating costs during the third quarter of 2006. During the third quarter of 2006, refinery utilization was 85%, compared to 96% in the third quarter of 2005. The lower utilization rate was due to planned maintenance in September of 2006.

Energy marketing and trading activities, including physical trading activities, resulted in net earnings of $8 million in the third quarter of 2006, compared to $2 million in the third quarter of 2005.

Cash flow from operations was $51 million in the third quarter of 2006, compared to $44 million in the third quarter of 2005. This increase reflects the impact of the same factors affecting net earnings excluding depreciation, depletion and amortization costs.

EM&R recorded net earnings of $98 million for the first nine months of 2006 compared to $19 million during the first nine months of 2005. The increase reflects strong refining margins, the one-time federal income tax rate reduction enacted in the second quarter of 2006, and the favourable judgment to Suncor of an outstanding vendor legal action in the second quarter of 2006. The decision is currently under appeal.

Cash flow from operations for the first nine months of 2006 was $204 million, compared to $92 million in the first nine months of 2005. The increase was primarily due to the same factors that affected net earnings, excluding the revaluation of deferred tax balances resulting from the reduction of federal income tax rates.

The first phase of our diesel desulphurization and oil sands integration project began commissioning in June 2006 and was completed in July 2006. As planned, phase two of the project will continue into 2007. However, labour shortages and material supply issues have put upward cost pressures on the overall project. As a result, the cost estimate for both phases of the project will likely increase.

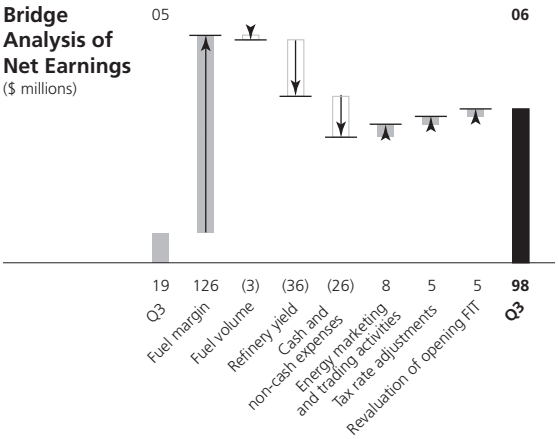
As of September 2006 a major maintenance shutdown was under way and is expected to affect our fourth quarter 2006 earnings. A significant portion of the shutdown work is directly related to phase two of our diesel desulphurization and oil sands integration project, and is impacted by the same labour and material supply pressures as noted above.

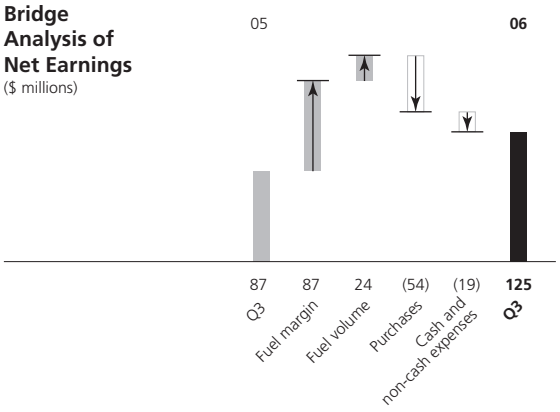
Our new ethanol facility began production on July 1, 2006. The facility, the largest of its kind in Canada, is expected to produce approximately 200 million litres of ethanol annually. The ethanol produced will be used for blending purposes in specific types of our gasoline products. The facility was completed on time and below budget, and is currently operating at design specifications.

For an update on our significant growth projects currently in progress see page 12.

Refining & Marketing – U.S.A. (R&M)

R&M recorded net earnings of $70 million in the third quarter of 2006 compared to net earnings of $50 million during the third quarter of 2005. The increase in net earnings for 2006 was primarily due to stronger refining margins. The increase was partially offset by lower retail margins and increased depreciation, depletion and





amortization costs after the completion of our maintenance shutdown in the second quarter of 2006, and our diesel desulphurization and oil sands integration project. During the third quarter of 2006 refinery utilization was 104%, consistent with the third quarter of 2005.

Cash flow from operations for the third quarter of 2006 was $118 million compared to $82 million in the third quarter of 2005. The increase was due to the same factors that increased net earnings, excluding depreciation, depletion and amortization.

R&M recorded net earnings of $125 million for the first nine months of 2006, compared to $87 million for the first nine months of 2005. The increase in net earnings was due to higher refining margins, a stronger sales mix of higher value diesel fuel, and the increased production volumes resulting from the acquisition of our second Commerce City refinery on May 31, 2005.

Cash flow from operations was $214 million for the nine months ended September 30, 2006, compared to $152 million during the same period in 2005. The increase in cash flow from operations was due to the same factors that increased net earnings.

With the completion of the diesel desulphurization and oil sands integration project during the second quarter of 2006, R&M is now expected to be capable of processing up to 15,000 bpd of sour synthetic crude oil from Suncor's oil sands operations.

Corporate

Corporate recorded net expenses in the third quarter of 2006 of $Nil, compared to net expenses of $1 million during the third quarter of 2005. After-tax unrealized foreign exchange on U.S. dollar denominated long-term debt was $Nil in the third quarter of 2006 compared to a $53 million gain in the third quarter of 2005.

The following corporate expenses for the nine month period ending September 2006, were higher than during the same period in 2005: financing expenses (no unrealized foreign exchange gains on U.S. dollar denominated long-term debt compared to a gain in 2005); depreciation, depletion and amortization for our new enterprise resource planning system implemented in January 2006; and eliminations of intersegment profits. These higher expenses were totally offset by a reduction in our stock-based compensation in the third quarter of 2006 compared to 2005 resulting from the decline in our share price, and insurance premium revenue earned by our wholly-owned self-insurance company. The self-insurance premium revenue is fully offset in the Oil Sands segment, and does not impact consolidated results (see page 6).

Cash used in operations was $10 million in the third quarter of 2006 compared to $20 million in the third quarter of 2005. Cash used in operations is lower primarily due to insurance related costs.

Corporate had net expenses of $136 million in the first nine months of 2006, compared to net expenses of $111 million in the same period of 2005. The increase in expenses, excluding unrealized foreign exchange, was primarily due to the same factors affecting net expenses during the third quarter of 2006 after the additional benefit of the revaluation of future tax balances resulting from the reduction of federal and Alberta income tax rates in the second quarter of 2006.

Cash flow used in operations was $98 million in the nine months ended September 30, 2006 compared to cash flow used in operations of $161 million in the nine months ended September 30, 2005. The decrease was due to the same factors that impacted third quarter 2006 cash flow from operations.

Analysis of Financial Condition and Liquidity

Excluding cash and cash equivalents, short-term debt and future income taxes, Suncor had an operating working capital surplus of $35 million at the end of the third quarter, compared to a deficiency of $223 million at the end of the third quarter of 2005.

During the first nine months of 2006, net debt decreased to approximately $1.8 billion from $2.9 billion at December 31, 2005. The decrease in debt levels was primarily a result of higher cash flow from operations and unrealized foreign exchange gains on U.S. dollar denominated long-term debt.

At September 30, 2006 our undrawn lines of credit were approximately $2.1 billion. We believe we have the capital resources from our undrawn lines of credit, cash flow from operations, and if necessary additional sources of financing to fund our 2006 capital spending program and to meet our current working capital requirements. If additional capital is required, we believe adequate additional financing is available at market terms and rates. As reported in our 2005 Annual Report, we anticipate capital spending of approximately $3.5 billion for 2006.

Effective May 15, 2006 one of our business interruption insurance providers discontinued operations. During the third quarter 2006, our Oil Sands business recorded additional premium expenses for losses incurred by this insurer for claims relating to activity in the Gulf of Mexico during the summer of 2005. We continue to evaluate options to replace this coverage and anticipate having resolution by early 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 final Board of Directors' approval.

(all amounts in $ millions)	Cost estimate [1]	Spent YTD in 2006	Total spent to date	Status [1]
Oil Sands				
Coker unit [2]	$2 100	$485	$1 425	Project is on schedule and on budget.
Firebag cogeneration and expansion	$400	$140	$260	Project is on schedule and on budget.
EM&R				
Diesel desulphurization and oil sands integration	$800	$230	$705	Diesel desulphurization component complete. Oil sands integration component is under upward cost pressures. Project cost estimate is under review.[3]
R&M				
Diesel desulphurization and oil sands integration	$540 (US$445)	$115 (US$95)	$530 (US$435)	Project complete.[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. The projects noted in the above table have cost estimates within this range of uncertainty. 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) Excludes costs associated with bitumen feed

(3) See page 10 for discussion.

(4) In the first quarter of 2006, the project budget was increased to a final expected cost of US$445 million from then-current estimates of US$390 million.

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

To date approximately $900 million has been approved for planning and scoping initiatives related to project design for the third upgrader.

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

Derivative Financial Instruments

We have continued to enter into crude oil costless collar hedges during the third quarter of 2006. As at September 30, 2006, crude oil hedges totaling 50,000 bpd of production were outstanding for the remainder of 2006, 60,000 bpd for 2007, and 10,000 bpd for 2008. These costless collar hedges have a floor ranging between US$50 to US$60/bbl and a ceiling of approximately US$92/bbl in 2007 up to US$101/bbl in 2008.

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

We had no crude oil hedging losses in the third quarter of 2006 compared to an after-tax loss of $102 million in the third quarter of 2005. This was primarily as a result of crude oil swaps placed in prior years which expired by December 31, 2005.

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 September 30:

($ millions)	**2006**	2005
Revenue hedge swaps and collars	**14**	(184)
Margin hedge swaps	**—**	(17)
Interest rate and cross-currency interest rate swaps	**13**	27
Specific cash flow hedges of individual transactions	**(3)**	14
	24	(160)

Energy Marketing and Trading Activities

For the third quarter ended September 30, 2006, we recorded a net pretax loss of $2 million compared to $3 million of net pretax earnings recorded during the third quarter of 2005, related to the settlement and revaluation of financial energy trading contracts.

In the third quarter, the settlement of physical trading activities resulted in net pretax earnings of $14 million compared to $1 million of net pretax earnings in the third quarter of 2005. These balances were included as energy marketing and trading activities in the Consolidated Statement of Earnings.

The above amounts do not include the impact of related general and administrative costs. Total after-tax energy marketing and trading activities resulted in earnings of $8 million for the quarter ended September 30, 2006, compared to earnings of $2 million for the third quarter of 2005.

The fair value of unsettled financial energy trading assets and liabilities at September 30, 2006 and December 31, 2005 were as follows:

($ millions)	**2006**	2005
Energy trading assets	**24**	82
Energy trading liabilities	**17**	70
Net trading assets	**7**	12

Control Environment

Based on their evaluation as of September 30, 2006, 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 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 SEC rules and forms. In addition, other than as described below, as of September 30, 2006, there were no changes in our internal control over financial reporting that occurred during the three month period ended September 30, 2006 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.

Since the beginning of the 2006 fiscal year, our internal control over financial reporting has undergone significant changes and redesign as all our businesses have implemented our new ERP system, designed to support our growth plan. Implementing an ERP system on a widespread basis involves major changes in business processes and extensive organizational training. We believe our phased-in approach reduces the risks associated with making these changes. In addition, we are taking the steps we believe are necessary to monitor and maintain appropriate internal controls during this transition period. These steps include deploying resources to mitigate internal control risks and performing additional verifications and testing to ensure data integrity.

Change in Accounting Policies

(a) Overburden Removal Costs

On January 1, 2006, the company retroactively adopted EIC 160 "Stripping Costs Incurred in the Production Phase of a Mining Operation". Under the new standard, overburden removal costs should be deferred and amortized only in instances where the activity benefits future periods, otherwise the costs should be charged to earnings in the period incurred. At Suncor, overburden removal precedes mining of the oil sands deposit within the normal operating cycle, and is related to current production. In accordance with the new standard, overburden removal costs are treated as variable production costs and expensed as incurred. Previously overburden removal was deferred and amortized on a life of mine approach.

(b) Non-monetary Transactions

On January 1, 2006, the company prospectively adopted CICA Handbook section 3831 "Non-monetary Transactions". The standard requires all non-monetary transactions to be measured at fair value (if determinable) unless future cash flows are not expected to change significantly as a result of a transaction or the transaction is an exchange of a product held for sale in the ordinary course of business. The company was required to record the effects of an existing contract at Oil Sands that exchanges off-gas produced as a by-product of the upgrading operations

for natural gas. An equal amount of revenues for the sale of the off-gas, and purchases of crude oil and products for the purchase of the natural gas was recorded. The amount of the gross-up of revenues and purchases of crude oil and products in the third quarter of 2006 was $25 million. For the nine months ended September 30, 2006 the amount of total gross-up of revenues and purchases of crude oil and products was $104 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 September 30, 2006 interim basis, please refer to page 30 of the third quarter 2006 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 September 30, 2006 unaudited interim consolidated financial statements.

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

		3 months ended September 30		9 months ended September 30	
		2006	2005	**2006**	2005
Cash flow from operations ($ millions)	A	**1 153**	651	**3 787**	1 250
Weighted average number of common shares outstanding (millions of shares)	B	**459.4**	457.0	**458.9**	456.0
Cash flow from operations (per share)	(A / B)	**2.51**	1.42	**8.25**	2.74

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 Firebag in-situ reconcile to the schedules of segmented data when combined.

OIL SANDS OPERATING COSTS – TOTAL OPERATIONS

		Quarter ended September 30				Nine months ended September 30			
		2006		2005 [1]		**2006**		2005 [1]	
		$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses		**510**		353		**1 474**		966	
Less: natural gas costs and inventory changes		**(32)**		(73)		**(199)**		(178)	
Less: non-monetary transactions		**(25)**		—		**(104)**			
Accretion of asset retirement obligations		**7**		7		**21**		18	
Taxes other than income taxes		**9**		8		**28**		22	
Cash costs		**469**	**21.00**	295	21.65	**1 220**	**17.30**	828	21.85
Natural gas		**58**	**2.60**	82	6.00	**202**	**2.85**	192	5.05
Imported bitumen (net of other reported product purchases)		**3**	**0.10**	—	—	**6**	**0.10**	1	0.05
Total cash operating costs	A	**530**	**23.70**	377	27.65	**1 428**	**20.25**	1 021	26.95
In-situ (Firebag) start-up costs	B	**—**	**—**	—	—	**21**	**0.30**	—	—
Total cash operating costs after start-up costs	A+B	**530**	**23.70**	377	27.65	**1 449**	**20.55**	1 021	26.95
Depreciation, depletion and amortization		**96**	**4.30**	83	6.10	**281**	**4.00**	241	6.35
Total operating costs		**626**	**28.00**	460	33.75	**1 730**	**24.55**	1 262	33.30
Production (thousands of barrels per day)		**242.8**		148.2		**258.1**		138.8	

OIL SANDS OPERATING COSTS – IN-SITU BITUMEN PRODUCTION

		Quarter ended September 30				Nine months ended September 30			
		2006		2005 (1)		**2006**		2005 (1)	
		$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses		**44**		44		**128**		106	
Less: natural gas costs and inventory changes		**(26)**		(28)		**(71)**		(58)	
Taxes other than income taxes		**1**		—		**3**		—	
Cash costs		**19**	**5.55**	16	7.55	**60**	**6.60**	48	10.45
Natural gas		**26**	**7.60**	28	13.25	**71**	**7.80**	58	12.65
Cash operating costs	A	**45**	**13.15**	44	20.80	**131**	**14.40**	106	23.10
In-situ (Firebag) start-up costs	B	**—**	**—**	—	—	**21**	**2.30**	—	—
Total cash operating costs after start-up costs	A+B	**45**	**13.15**	44	20.80	**152**	**16.70**	106	23.10
Depreciation, depletion and amortization		**19**	**5.55**	9	4.25	**48**	**5.30**	23	5.00
Total operating costs		**64**	**18.70**	53	25.05	**200**	**22.00**	129	28.10
Production (thousands of barrels per day)		**37.2**		23.0		**33.3**		16.8	

(1) Firebag start-up costs have not previously been separately identified in past quarterly Reports to Shareholders. We have segregated these costs for comparable information purposes to provide additional detail to the individual components of cash costs.

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," "vision," "goal," "will likely," "may," "pending," "proposed," "target," "objective," 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 (for example, the clean fuels refinery modifications projects in our downstream businesses); 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; 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 the fires, 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)	Third quarter 2006	Third quarter 2005 (restated) (note 2)	Nine months ended Sept 30 2006	Nine months ended Sept 30 2005 (restated) (note 2)
Revenues	**4 114**	3 149	**12 042**	7 608
Expenses				
Purchases of crude oil and products	**1 472**	1 311	**3 656**	3 166
Operating, selling and general (notes 2 and 6)	**656**	602	**2 082**	1 682
Energy marketing and trading activities (note 3)	**427**	237	**1 043**	598
Transportation and other costs	**54**	35	**152**	102
Depreciation, depletion and amortization (note 2)	**180**	145	**504**	419
Accretion of asset retirement obligations	**9**	8	**26**	23
Exploration	**18**	29	**80**	48
Royalties (note 10)	**143**	172	**771**	410
Taxes other than income taxes	**156**	160	**438**	406
Gain on disposal of assets	**(2)**	—	**(5)**	(1)
Project start-up costs	**13**	7	**39**	13
Financing income (note 4)	**—**	(58)	**(13)**	(30)
	3 126	2 648	**8 773**	6 836
Earnings Before Income Taxes	**988**	501	**3 269**	772
Provision for (Recovery of) Income Taxes (notes 2 and 9)				
Current	**(2)**	(16)	**(11)**	37
Future	**308**	202	**667**	270
	306	186	**656**	307
Net Earnings	**682**	315	**2 613**	465
Per Common Share (dollars), (note 5)				
Basic	**1.48**	0.69	**5.69**	1.02
Diluted	**1.45**	0.67	**5.56**	1.00
Cash dividends	**0.08**	0.06	**0.22**	0.18

See accompanying notes.

CONSOLIDATED BALANCE SHEETS

(unaudited)

($ millions)	**September 30 2006**	December 31 2005 (restated) (note 2)
Assets		
Current assets		
Cash and cash equivalents	**290**	165
Accounts receivable	**1 210**	1 139
Inventories	**648**	523
Income taxes receivable	**22**	6
Future income taxes	**65**	83
Total current assets	**2 235**	1 916
Property, plant and equipment, net	**14 849**	12 966
Deferred charges and other (note 2)	**260**	267
Total assets	**17 344**	15 149
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**8**	49
Accounts payable and accrued liabilities (note 10)	**1 788**	1 830
Taxes other than income taxes	**57**	56
Total current liabilities	**1 853**	1 935
Long-term debt	**2 070**	3 007
Accrued liabilities and other	**1 017**	1 005
Future income taxes (notes 2 and 9)	**3 852**	3 206
Shareholders' equity (see below)	**8 552**	5 996
Total liabilities and shareholders' equity	**17 344**	15 149

Shareholders' Equity

	Number (thousands)		Number (thousands)	
Share capital	**459 596**	**784**	457 665	732
Contributed surplus		**76**		50
Cumulative foreign currency translation		**(117)**		(81)
Retained earnings (note 2)		**7 809**		5 295
		8 552		5 996

See accompanying notes.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)

($ millions)	Third quarter 2006	Third quarter 2005 (restated) (note 2)	Nine months ended Sept 30 2006	Nine months ended Sept 30 2005 (restated) (note 2)
Operating Activities				
Cash flow from operations	**1 153**	651	**3 787**	1 250
Decrease (increase) in operating working capital				
Accounts receivable	**49**	(429)	**(100)**	(604)
Inventories	**(98)**	44	**(125)**	4
Accounts payable and accrued liabilities	**219**	87	**(147)**	469
Taxes receivable	**(38)**	(19)	**(15)**	(47)
Cash flow from operating activities	**1 285**	334	**3 400**	1 072
Cash Used in Investing Activities	**(866)**	(769)	**(2 320)**	(2 216)
Net Cash Surplus (Deficiency) Before Financing Activities	**419**	(435)	**1 080**	(1 144)
Financing Activities				
Decrease in short-term debt	**—**	(6)	**(41)**	(26)
Net increase (decrease) in other long-term debt	**(270)**	483	**(886)**	1 141
Issuance of common shares under stock option plan	**7**	10	**40**	62
Dividends paid on common shares	**(34)**	(26)	**(92)**	(77)
Deferred revenue	**11**	11	**27**	41
Cash provided by (used in) financing activities	**(286)**	472	**(952)**	1 141
Increase (Decrease) in Cash and Cash Equivalents	**133**	37	**128**	(3)
Effect of Foreign Exchange on Cash and Cash Equivalents	**(1)**	—	**(3)**	—
Cash and Cash Equivalents at Beginning of Period	**158**	48	**165**	88
Cash and Cash Equivalents at End of Period	**290**	85	**290**	85

See accompanying notes.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(unaudited)

($ millions)	Share Capital	Contributed Surplus	Cumulative Foreign Currency Translation	Retained Earnings
At December 31, 2004, as previously reported	651	32	(55)	4 293
Retroactive adjustment for change in accounting policy, net of tax (note 2)	—	—	—	(47)
At December 31, 2004, as restated	651	32	(55)	4 246
Net earnings	—	—	—	465
Dividends paid on common shares	—	—	—	(77)
Issued for cash under stock option plan	67	(5)	—	—
Issued under dividend reinvestment plan	5	—	—	(5)
Stock-based compensation expense	—	16	—	—
Foreign currency translation adjustment	—	—	(28)	—
At September 30, 2005	723	43	(83)	4 629
At December 31, 2005, as previously reported	732	50	(81)	5 429
Retroactive adjustment for change in accounting policy, net of tax (note 2)	—	—	—	(134)
At December 31, 2005, as restated	732	50	(81)	5 295
Net earnings	**—**	**—**	**—**	**2 613**
Dividends paid on common shares	**—**	**—**	**—**	**(92)**
Issued for cash under stock option plan	**45**	**(5)**	**—**	**—**
Issued under dividend reinvestment plan	**7**	**—**	**—**	**(7)**
Stock-based compensation expense	**—**	**31**	**—**	**—**
Foreign currency translation adjustment	**—**	**—**	**(36)**	**—**
At September 30, 2006	**784**	**76**	**(117)**	**7 809**

See accompanying notes.

SCHEDULES OF SEGMENTED DATA

(unaudited)

											Third quarter	
	Oil Sands		Natural Gas		Energy Marketing and Refining – Canada		Refining and Marketing – U.S.A.		Corporate and Eliminations		Total	
($ millions)	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005
EARNINGS												
Revenues												
Operating revenues	**1 573**	623	**126**	164	**1 022**	982	**949**	924	**2**	—	**3 672**	2 693
Energy marketing and trading activities	**—**	—	**—**	—	**440**	245	**—**	—	**(2)**	—	**438**	245
Net insurance proceeds	**—**	211	**—**	—	**—**	—	**—**	—	**—**	—	**—**	211
Intersegment revenues	**135**	163	**6**	10	**—**	—	**—**	—	**(141)**	(173)	**—**	—
Interest	**—**	—	**1**	—	**—**	—	**2**	—	**1**	—	**4**	—
	1 708	997	**133**	174	**1 462**	1 227	**951**	924	**(140)**	(173)	**4 114**	3 149
Expenses												
Purchases of crude oil and products	**71**	8	**—**	—	**792**	740	**732**	731	**(123)**	(168)	**1 472**	1 311
Operating, selling and general	**510**	353	**29**	25	**94**	114	**44**	48	**(21)**	62	**656**	602
Energy marketing and trading activities	**—**	—	**—**	—	**429**	241	**—**	—	**(2)**	(4)	**427**	237
Transportation and other costs	**41**	23	**6**	5	**1**	1	**6**	6	**—**	—	**54**	35
Depreciation, depletion and amortization	**96**	83	**38**	36	**27**	18	**13**	6	**6**	2	**180**	145
Accretion of asset retirement obligations	**7**	7	**1**	1	**1**	—	**—**	—	**—**	—	**9**	8
Exploration	**—**	—	**18**	29	**—**	—	**—**	—	**—**	—	**18**	29
Royalties (note 10)	**119**	136	**24**	36	**—**	—	**—**	—	**—**	—	**143**	172
Taxes other than income taxes	**17**	20	**1**	1	**93**	86	**44**	53	**1**	—	**156**	160
Gain on disposal of assets	**—**	—	**(1)**	—	**—**	—	**(1)**	—	**—**	—	**(2)**	—
Project start-up costs	**8**	7	**—**	—	**—**	—	**5**	—	**—**	—	**13**	7
Financing expenses (income)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	(58)	**—**	(58)
	869	637	**116**	133	**1 437**	1 200	**843**	844	**(139)**	(166)	**3 126**	2 648
Earnings (loss) before income taxes	**839**	360	**17**	41	**25**	27	**108**	80	**(1)**	(7)	**988**	501
Income taxes	**(256)**	(135)	**(5)**	(17)	**(8)**	(10)	**(38)**	(30)	**1**	6	**(306)**	(186)
Net earnings (loss)	**583**	225	**12**	24	**17**	17	**70**	50	**—**	(1)	**682**	315

SCHEDULES OF SEGMENTED DATA (continued)

(unaudited)

($ millions)	Oil Sands 2006	Oil Sands 2005	Natural Gas 2006	Natural Gas 2005	Energy Marketing and Refining – Canada 2006	Energy Marketing and Refining – Canada 2005	Refining and Marketing – U.S.A. 2006	Refining and Marketing – U.S.A. 2005	Corporate and Eliminations 2006	Corporate and Eliminations 2005	Total 2006	Total 2005
											Third quarter	
CASH FLOW BEFORE FINANCING ACTIVITIES												
Cash flow from (used in) operating activities:												
Cash flow from (used in) operations												
Net earnings (loss)	**583**	225	**12**	24	**17**	17	**70**	50	**—**	(1)	**682**	315
Exploration expenses	**—**	—	**15**	29	**—**	—	**—**	—	**—**	—	**15**	29
Non-cash items included in earnings												
Depreciation, depletion and amortization	**96**	83	**38**	36	**27**	18	**13**	6	**6**	2	**180**	145
Income taxes	**256**	135	**5**	17	**8**	10	**38**	30	**1**	10	**308**	202
Gain on disposal of assets	**—**	—	**(1)**	—	**—**	—	**(1)**	—	**—**	—	**(2)**	—
Stock-based compensation expense	**—**	—	**—**	—	**—**	—	**—**	—	**12**	6	**12**	6
Other	**(4)**	2	**(1)**	(2)	**(2)**	(1)	**(2)**	(4)	**(13)**	(61)	**(22)**	(66)
Increase (decrease) in deferred credits and other	**(5)**	(4)	**—**	—	**1**	—	**—**	—	**(16)**	24	**(20)**	20
Total cash flow from (used in) operations	**926**	441	**68**	104	**51**	44	**118**	82	**(10)**	(20)	**1 153**	651
Decrease (increase) in operating working capital	**(73)**	(273)	**35**	(14)	**11**	13	**(12)**	103	**171**	(146)	**132**	(317)
Total cash flow from (used in) operating activities	**853**	168	**103**	90	**62**	57	**106**	185	**161**	(166)	**1 285**	334
Cash from (used in) investing activities:												
Capital and exploration expenditures	**(585)**	(563)	**(99)**	(87)	**(88)**	(114)	**(14)**	(95)	**(9)**	(17)	**(795)**	(876)
Acquisition of Denver refinery and related assets	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Deferred maintenance shutdown expenditures	**—**	(4)	**—**	(3)	**(4)**	—	**—**	(3)	**—**	—	**(4)**	(10)
Deferred outlays and other investments	**—**	—	**—**	—	**1**	1	**1**	—	**(12)**	2	**(10)**	3
Proceeds from disposals	**1**	—	**(1)**	2	**—**	1	**—**	—	**—**	—	**—**	3
Proceeds from property loss	**—**	44	**—**	—	**—**	—	**—**	—	**—**	—	**—**	44
Decrease (increase) in investing working capital	**(29)**	43	**—**	—	**(14)**	9	**(14)**	15	**—**	—	**(57)**	67
Total cash (used in) investing activities	**(613)**	(480)	**(100)**	(88)	**(105)**	(103)	**(27)**	(83)	**(21)**	(15)	**(866)**	(769)
Net cash surplus (deficiency) before financing activities	**240**	(312)	**3**	2	**(43)**	(46)	**79**	102	**140**	(181)	**419**	(435)

SCHEDULES OF SEGMENTED DATA (continued)

(unaudited)

											Nine months ended September 30	
	Oil Sands		Natural Gas		Energy Marketing and Refining – Canada		Refining and Marketing – U.S.A.		Corporate and Eliminations		Total	
($ millions)	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005
EARNINGS												
Revenues												
Operating revenues	**4 765**	1 636	**420**	412	**2 962**	2 634	**2 425**	1 910	**4**	1	**10 576**	6 593
Energy marketing and trading activities	**—**	—	**—**	—	**1 097**	627	**—**	—	**(25)**	—	**1 072**	627
Net insurance proceeds	**385**	387	**—**	—	**—**	—	**—**	—	**—**	—	**385**	387
Intersegment revenues	**581**	316	**23**	36	**—**	—	**—**	—	**(604)**	(352)	**—**	—
Interest	**—**	—	**1**	—	**—**	—	**3**	1	**5**	—	**9**	1
	5 731	2 339	**444**	448	**4 059**	3 261	**2 428**	1 911	**(620)**	(351)	**12 042**	7 608
Expenses												
Purchases of crude oil and products	**88**	29	**—**	—	**2 206**	1 959	**1 940**	1 513	**(578)**	(335)	**3 656**	3 166
Operating, selling and general	**1 474**	966	**80**	69	**315**	339	**128**	119	**85**	189	**2 082**	1 682
Energy marketing and trading activities	**—**	—	**—**	—	**1 072**	615	**—**	—	**(29)**	(17)	**1 043**	598
Transportation and other costs	**114**	68	**17**	16	**5**	4	**16**	14	**—**	—	**152**	102
Depreciation, depletion and amortization	**281**	241	**110**	97	**69**	54	**25**	18	**19**	9	**504**	419
Accretion of asset retirement obligations	**21**	18	**4**	4	**1**	1	**—**	—	**—**	—	**26**	23
Exploration	**22**	10	**58**	38	**—**	—	**—**	—	**—**	—	**80**	48
Royalties (note 10)	**682**	317	**89**	93	**—**	—	**—**	—	**—**	—	**771**	410
Taxes other than income taxes	**58**	34	**3**	2	**256**	258	**120**	112	**1**	—	**438**	406
Gain on disposal of assets	**—**	—	**(5)**	—	**—**	(1)	**—**	—	**—**	—	**(5)**	(1)
Project start-up costs	**32**	13	**—**	—	**2**	—	**5**	—	**—**	—	**39**	13
Financing income	**—**	—	**—**	—	**—**	—	**—**	—	**(13)**	(30)	**(13)**	(30)
	2 772	1 696	**356**	319	**3 926**	3 229	**2 234**	1 776	**(515)**	(184)	**8 773**	6 836
Earnings (loss) before income taxes	**2 959**	643	**88**	129	**133**	32	**194**	135	**(105)**	(167)	**3 269**	772
Income taxes	**(547)**	(250)	**26**	(52)	**(35)**	(13)	**(69)**	(48)	**(31)**	56	**(656)**	(307)
Net earnings (loss)	**2 412**	393	**114**	77	**98**	19	**125**	87	**(136)**	(111)	**2 613**	465
As at September 30												
TOTAL ASSETS	**12 933**	10 990	**1 370**	1 159	**2 930**	1 880	**1 290**	1 239	**(1 179)**	(720)	**17 344**	14 548

SCHEDULES OF SEGMENTED DATA (continued)

(unaudited)

											Nine months ended September 30	
	Oil Sands		Natural Gas		Energy Marketing and Refining – Canada		Refining and Marketing – U.S.A.		Corporate and Eliminations		Total	
($ millions)	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005
CASH FLOW BEFORE FINANCING ACTIVITIES												
Cash flow from (used in) operating activities:												
Cash flow from (used in) operations												
Net earnings (loss)	**2 412**	393	**114**	77	**98**	19	**125**	87	**(136)**	(111)	**2 613**	465
Exploration expenses	**—**	—	**40**	38	**—**	—	**—**	—	**—**	—	**40**	38
Non-cash items included in earnings												
Depreciation, depletion and amortization	**281**	241	**110**	97	**69**	54	**25**	18	**19**	9	**504**	419
Income taxes	**547**	250	**(26)**	52	**35**	13	**69**	48	**42**	(93)	**667**	270
Gain on disposal of assets	**—**	—	**(5)**	—	**—**	(1)	**—**	—	**—**	—	**(5)**	(1)
Stock-based compensation expense	**—**	—	**—**	—	**—**	—	**—**	—	**31**	16	**31**	16
Other	**10**	25	**—**	4	**1**	7	**(2)**	(1)	**(39)**	(54)	**(30)**	(19)
Increase (decrease) in deferred credits and other	**(16)**	(10)	**—**	—	**1**	—	**(3)**	—	**(15)**	72	**(33)**	62
Total cash flow from (used in) operations	**3 234**	899	**233**	268	**204**	92	**214**	152	**(98)**	(161)	**3 787**	1 250
Decrease (increase) in operating working capital	**(295)**	(201)	**(6)**	(41)	**(65)**	(29)	**20**	45	**(41)**	48	**(387)**	(178)
Total cash flow from (used in) operating activities	**2 939**	698	**227**	227	**139**	63	**234**	197	**(139)**	(113)	**3 400**	1 072
Cash from (used in) investing activities:												
Capital and exploration expenditures	**(1 547)**	(1 443)	**(341)**	(241)	**(323)**	(306)	**(178)**	(258)	**(23)**	(41)	**(2 412)**	(2 289)
Acquisition of Denver refinery and related assets	**—**	—	**—**	—	**—**	—	**—**	(62)	**—**	—	**—**	(62)
Deferred maintenance shutdown expenditures	**—**	(64)	**—**	(3)	**(5)**	—	**(51)**	(4)	**—**	—	**(56)**	(71)
Deferred outlays and other investments	**(2)**	(1)	**—**	—	**1**	(1)	**6**	—	**(5)**	1	**—**	(1)
Proceeds from disposals	**1**	21	**13**	2	**3**	2	**—**	—	**—**	—	**17**	25
Proceeds from property loss	**29**	44	**—**	—	**—**	—	**—**	—	**—**	—	**29**	44
Decrease (increase) in investing working capital	**154**	91	**—**	—	**—**	18	**(52)**	29	**—**	—	**102**	138
Total cash (used in) investing activities	**(1 365)**	(1 352)	**(328)**	(242)	**(324)**	(287)	**(275)**	(295)	**(28)**	(40)	**(2 320)**	(2 216)
Net cash surplus (deficiency) before financing activities	**1 574**	(654)	**(101)**	(15)	**(185)**	(224)	**(41)**	(98)	**(167)**	(153)	**1 080**	(1 144)

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.

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 September 30, 2006 and the results of its operations and cash flows for the three and nine month periods ended September 30, 2006 and 2005.

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

2. CHANGES IN ACCOUNTING POLICIES

(a) Overburden Removal Costs

On January 1, 2006, the company retroactively adopted EIC 160 "Stripping Costs Incurred in the Production Phase of a Mining Operation". Under the new standard, overburden removal costs should be deferred and amortized only in instances where the activity benefits future periods, otherwise the costs should be charged to earnings in the period incurred. At Suncor, overburden removal precedes mining of the oil sands deposit within the normal operating cycle, and is related to current production. In accordance with the new standard, overburden removal costs are treated as variable production costs and expensed as incurred. Previously overburden removal was deferred and amortized on a life-of-mine approach. The impact of adopting this accounting standard is as follows:

Change in Consolidated Balance Sheets

	As at September 30	
($ millions, (decrease))	**2006**	2005
Deferred charges and other	**(233)**	(199)
Total assets	**(233)**	(199)
Future income tax liabilities	**(78)**	(66)
Retained earnings	**(155)**	(133)
Total liabilities and shareholders' equity	**(233)**	(199)

Change in Consolidated Statements of Earnings

	Third quarter		Nine months ended September 30	
($ millions, increase/(decrease))	**2006**	2005	**2006**	2005
Operating, selling and general	**80**	68	**239**	220
Depreciation, depletion and amortization	**(91)**	(29)	**(208)**	(88)
Future income taxes	**3**	(13)	**(10)**	(46)
Net earnings	**8**	(26)	**(21)**	(86)
Per common share – basic (dollars)	**0.02**	(0.06)	**(0.05)**	(0.19)
Per common share – diluted (dollars)	**0.02**	(0.06)	**(0.04)**	(0.18)

(b) Non-monetary Transactions

On January 1, 2006, the company prospectively adopted CICA Handbook section 3831 "Non-monetary Transactions". The standard requires all non-monetary transactions to be measured at fair value (if determinable) unless future cash flows are not expected to change significantly as a result of a transaction or the transaction is an exchange of a product held for sale in the ordinary course of business. The company was required to record the effects of an existing contract at Oil Sands that exchanges off-gas produced as a by-product of the upgrading operations for natural gas. An equal amount of revenues for the sale of the off-gas, and purchases of crude oil and products for the purchase of the natural gas are recorded. The amount of the gross-up of revenues and purchases of crude oil and products for the three and nine month periods ending September 30, 2006 was $25 million and $104 million respectively.

3. ENERGY MARKETING AND TRADING ACTIVITIES

The company uses physical and financial energy contracts, including swaps, forwards and options to gain market information and 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. The results of these activities are reported as revenue and as energy marketing and trading expenses in the Consolidated Statements of Earnings.

Physical energy marketing contracts involve activities intended to enhance prices and satisfy physical deliveries to customers. For the quarter ended September 30, 2006, these activities resulted in net pretax earnings of $14 million (2005 – net pretax earnings of $1 million). For the nine months ended September 30, 2006, physical energy marketing contracts resulted in net pretax earnings of $30 million (2005 – net pretax earnings of $10 million).

In addition to the financial derivatives used for hedging activities, the company also enters into various financial energy contracts for trading activities. The following information presents all positions for the trading financial instruments only. For the quarter ended September 30, 2006, a net pretax loss of $2 million (2005 – net pretax earnings of $3 million) resulted from the settlement and revaluation of the financial energy contracts. For the nine months ended September 30, 2006 a net pretax loss of $3 million (2005 – net pretax earnings of $4 million) was recorded. The above amounts do not include the impact of related general and administrative costs.

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

($ millions)	**September 30 2006**	December 31 2005
Energy trading assets	**24**	82
Energy trading liabilities	**17**	70
Net energy trading assets	**7**	12

Change in Fair Value of Net Assets

($ millions)	**2006**
Fair value of contracts outstanding at December 31, 2005	12
Fair value of contracts realized during 2006	**(2)**
Fair value of contracts entered into during the period	**5**
Changes in values attributable to market price and other market changes	**(8)**
Fair value of contracts outstanding at September 30, 2006	**7**

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

4. FINANCING EXPENSES (INCOME)

	Third quarter		Nine months ended September 30	
($ millions)	**2006**	2005	**2006**	2005
Interest on debt	**35**	39	**112**	110
Capitalized interest	**(30)**	(34)	**(94)**	(91)
Net interest expense	**5**	5	**18**	19
Foreign exchange gain on long-term debt	**—**	(64)	**(51)**	(42)
Other foreign exchange loss (gain)	**(5)**	1	**20**	(7)
Total financing expenses (income)	**—**	(58)	**(13)**	(30)

5. RECONCILIATION OF BASIC AND DILUTED EARNINGS PER COMMON SHARE

($ millions)	Third quarter 2006	Third quarter 2005	Nine months ended September 30 2006	Nine months ended September 30 2005
Net earnings	**682**	315	**2 613**	465
(millions of common shares)				
Weighted-average number of common shares	**459**	457	**459**	456
Options issued under stock-based compensation plans	**11**	11	**11**	9
Weighted-average number of diluted common shares	**470**	468	**470**	465
(dollars per common share)				
Basic earnings per share [(a)]	**1.48**	0.69	**5.69**	1.02
Diluted earnings per share [(b)]	**1.45**	0.67	**5.56**	1.00

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.

6. 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 634,000 options to new employees in the third quarter of 2006, for a total of 1,232,000 options granted in the nine months ended September 30, 2006 (314,000 options granted during the third quarter of 2005; 991,000 options granted in the nine months ended September 30, 2005).

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.

Under the company's other plans, 11,000 options were granted in the third quarter of 2006, for a total of 1,582,000 options granted in the nine months ended September 30, 2006 (63,000 options granted during the third quarter of 2005; 1,418,000 granted in the nine months ended September 30, 2005).

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:

	Third quarter 2006	Third quarter 2005	Nine months ended September 30 2006	Nine months ended September 30 2005
Quarterly dividend per share	**$0.08**	$0.06	**$0.08**	$0.06
Risk-free interest rate	**4.14%**	3.42%	**4.11%**	3.68%
Expected life	**4 years**	5 years	**5 years**	6 years
Expected volatility	**30%**	28%	**29%**	28%
Weighted-average fair value per option	**$25.40**	$19.17	**$30.16**	$14.89

* In 2006, quarterly dividends of $0.06 per share were paid in the first quarter and $0.08 per share were paid in the second and third quarters.

Stock-based compensation expense recognized in the third quarter of 2006 related to stock options plans was $12 million (2005 – $6 million). For the nine months ended September 30, 2006 stock-based compensation expense recognized was $31 million (2005 – $16 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:

	Third quarter		Nine months ended September 30	
($ millions, except per share amounts)	**2006**	2005	**2006**	2005
Net earnings – as reported	**682**	315	**2 613**	465
Less: compensation cost under the fair value method for pre-2003 options	**2**	2	**7**	11
Pro forma net earnings	**680**	313	**2 606**	454
Basic earnings per share				
As reported	**1.48**	0.69	**5.69**	1.02
Pro forma	**1.48**	0.68	**5.68**	1.00
Diluted earnings per share				
As reported	**1.45**	0.67	**5.56**	1.00
Pro forma	**1.44**	0.67	**5.54**	0.98

(b) Performance Share Units (PSUs)

In the third quarter of 2006 the company issued 3,000 PSUs (2005 – 6,000). For the nine months ended September 30, 2006, the company issued 395,000 PSUs (2005 – 451,000). The reversal of previously recognized expense due to a decline in share price in the third quarter of 2006 was $10 million (2005 – expense recognized was $8 million). Expense recognized for the nine months ended September 30, 2006 was $25 million (2005 – $16 million).

7. EMPLOYEE FUTURE BENEFITS LIABILITY

The company's pension plans and other post-retirement benefits programs are described in note 8 of the company's 2005 Annual Report. The following is the status of the net periodic benefit cost for the quarter and nine months ended September 30.

	Pension Benefits			
	Third quarter		Nine months ended September 30	
($ millions)	**2006**	2005	**2006**	2005
Current service costs	**11**	8	**33**	24
Interest costs	**10**	10	**30**	29
Expected return on plan assets	**(8)**	(7)	**(24)**	(21)
Amortization of net actuarial loss	**7**	4	**21**	15
Net periodic benefit cost	**20**	15	**60**	47

	Other Post-retirement Benefits			
	Third quarter		Nine months ended September 30	
($ millions)	**2006**	2005	**2006**	2005
Current service costs	**1**	2	**4**	5
Interest costs	**2**	1	**6**	5
Amortization of net actuarial loss	**1**	1	**1**	1
Net periodic benefit cost	**4**	4	**11**	11

8. SUPPLEMENTAL INFORMATION

	Third quarter		Nine months ended September 30	
($ millions)	**2006**	2005	**2006**	2005
Interest paid	**48**	53	**123**	122
Income taxes paid (received)	**(12)**	6	**5**	61

Revenue Hedges

Strategic Crude Oil at September 30, 2006

	Quantity (bpd)	Average Price (US$/bbl) [a]	Revenue Hedged (Cdn$ millions) [b]	Hedge Period [c]
Costless collars	50 000	50.00 – 91.70	257 – 470	2006
Costless collars	60 000	51.64 – 93.26	1 261 – 2 278	2007
Costless collars	10 000	59.85 – 101.06	244 – 413	2008

Natural Gas at September 30, 2006

	Quantity (GJ/day)	Average Price (Cdn$/GJ)	Revenue Hedged (Cdn$ millions)	Hedge Period [c]
Swaps	4 000	6.58	2	2006
Costless collars	10 000	8.75 – 13.38	3 – 4	2006 [d]
Costless collars	20 000	6.13 – 8.00	7 – 10	2006 [e]
Swaps	4 000	6.11	9	2007

Foreign Currency Hedges at September 30, 2006

	Notional (Euro millions)	Average Forward Rate	Dollars Hedged (Cdn$ millions)	Hedge Period
Euro/Cdn forward	20.6	1.40	29	2007 [f]

(a) Average price for crude oil costless collars is US$ WTI per barrel at Cushing, Oklahoma.

(b) The revenue hedged is translated to Cdn$ at the September 30, 2006 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 October 1 to October 31, 2006, inclusive.

(e) For the period October to November 2006, inclusive.

(f) Settlements for applicable forwards occurring within the period April to September 2007.

9. INCOME TAXES

During the second quarter of 2006 the federal government substantively enacted a 3.1% reduction to its federal corporate tax rates. Accordingly, the company recognized a reduction in future income tax expense of $292 million related to the revaluation of its opening future income tax balances.

As well, the provincial government of Alberta substantively enacted a 1.5% reduction to its provincial corporate tax rates during the second quarter of 2006. Accordingly, the company recognized a reduction in future income tax expense of $127 million related to the revaluation of its opening future income tax balances.

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. Firebag is being treated by the Government of Alberta as a separate project from the rest of the Oil Sands operations for royalty purposes.

In February 2006, we advised the Government of Alberta we would not proceed with a July 2004 claim we filed against the Crown where we were seeking to overturn the government's decision on the royalty treatment of our Firebag in-situ operations.

Oil Sands royalties payable in 2006 are highly sensitive to, among other factors, changes in crude oil and natural gas pricing, timing of the receipt of property damage insurance proceeds, foreign exchange rates and total capital and operating costs for each project. Oil Sands pretax royalty estimate was $682 million ($464 million after tax) for the first nine months of 2006 compared to $317 million ($196 million after tax) for the first nine months of 2005. We estimate 2006 annualized oil sands royalties to be approximately $880 million ($600 million after tax) based on nine months of actual results including the final $385 million in business interruption insurance proceeds, together with 2006 forward crude oil pricing of US$64.36 as at September 30, 2006, current forecasts of production, capital and operating costs for the remainder of 2006, a Canadian/US foreign exchange rate of $0.89, and no further receipts of property loss insurance proceeds other than those recorded to date. 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 $89 million ($61 million after tax).

11. CREDIT FACILITIES

During the second quarter, a $1.5 billion credit facility agreement was renegotiated and extended by two years, to have a five year term maturing in June 2011. The credit limit of this facility was also increased by $500 million to $2 billion. In addition, a $200 million credit facility agreement was renegotiated and increased by $100 million to $300 million. As well, a $600 million credit facility agreement matured during the second quarter and was not renewed. At September 30, 2006, the company had available facilities 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 three 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

As at September 30, 2006, undrawn lines of credit were approximately $2,088 million.

HIGHLIGHTS

(unaudited)

	2006	2005
Cash Flow from Operations		
(dollars per common share)		
For the three months ended September 30		
Cash flow from operations (1)	**2.51**	1.42
For the nine months ended September 30		
Cash flow from operations (1)	**8.25**	2.74
Ratios		
For the twelve months ended September 30		
Return on capital employed (%) (2)	**47.1**	12.6
Return on capital employed (%) (3)	**34.9**	9.6
Net debt to cash flow from operations (times) (4)	**0.4**	1.8
Interest coverage on long-term debt (times)		
Net earnings (5)	**28.6**	8.9
Cash flow from operations (6)	**32.9**	12.8
As at September 30		
Debt to debt plus shareholders' equity (%) (7)	**19.6**	38.6
Common Share Information		
As at September 30		
Share price at end of trading		
Toronto Stock Exchange – Cdn$	**80.19**	70.42
New York Stock Exchange – US$	**72.05**	60.53
Common share options outstanding (thousands)	**19 783**	19 378
For the nine months ended September 30		
Average number outstanding, weighted monthly (thousands)	**458 859**	455 962

Refer to the Quarterly Operating Summary for a discussion of financial measures not prepared in accordance with Canadian 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) Net earnings (2006 – $3,300 million; 2005 – $734 million) adjusted for after-tax financing expenses (2006 – income of $6 million; 2005 – expense of $57 million) for the twelve month period ended; divided by average capital employed (2006 – $7,009 million; 2005 – $5,843 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 56 of Suncor's 2005 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: 2006 – $9,453 million; 2005 – $7,676 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					Nine months ended		Total year
	Sep 30 2006	June 30 2006	Mar 31 2006	Dec 31 2005	Sep 30 2005	**Sep 30 2006**	Sep 30 2005	Dec 31 2005
OIL SANDS								
Production (1),(a)								
Total production	**242.8**	267.3	264.4	267.7	148.2	**258.1**	138.8	171.3
Firebag	**37.2**	35.0	27.4	26.0	23.0	**33.3**	16.8	19.1
Sales (a)								
Light sweet crude oil	**84.9**	124.7	119.2	108.6	69.9	**109.4**	64.4	73.3
Diesel	**20.7**	32.9	35.1	30.7	10.6	**29.6**	10.5	15.6
Light sour crude oil	**125.8**	99.2	121.0	104.2	41.7	**115.3**	44.8	59.8
Bitumen	**6.6**	8.5	—	7.2	22.3	**5.1**	16.8	16.6
Total sales	**238.0**	265.3	275.3	250.7	144.5	**259.4**	136.5	165.3
Average sales price (2),(b)								
Light sweet crude oil	**78.11**	78.27	69.00	55.96	52.08	**74.90**	46.34	49.93
Other (diesel, light sour crude oil and bitumen)	**68.60**	72.75	63.28	63.84	59.70	**68.09**	52.48	56.90
Total	**71.99**	75.34	65.75	60.42	56.01	**70.96**	49.72	53.81
Total *	**71.99**	75.34	65.75	66.68	67.95	**70.96**	60.21	62.68
CASH OPERATING COSTS AND TOTAL OPERATING COSTS – TOTAL OPERATIONS								
Cash costs	**21.00**	15.65	15.55	16.20	21.65	**17.30**	21.85	19.60
Natural gas	**2.60**	2.55	3.45	4.65	6.00	**2.85**	5.05	4.90
Imported bitumen	**0.10**	0.10	0.05	0.05	—	**0.10**	0.05	0.05
Cash operating costs (3),(c)	**23.70**	18.30	19.05	20.90	27.65	**20.25**	26.95	24.55
Firebag start-up costs	**—**	—	0.90	0.30	—	**0.30**	—	0.10
Total cash operating costs (4),(c)	**23.70**	18.30	19.95	21.20	27.65	**20.55**	26.95	24.65
Depreciation, depletion and amortization	**4.30**	3.80	3.90	3.60	6.10	**4.00**	6.35	5.30
Total operating costs (5),(c)	**28.00**	22.10	23.85	24.80	33.75	**24.55**	33.30	29.95
CASH OPERATING COSTS AND TOTAL OPERATING COSTS – IN-SITU BITUMEN PRODUCTION								
Cash costs	**5.55**	8.50	5.70	6.70	7.55	**6.60**	10.45	9.15
Natural gas	**7.60**	8.15	7.70	13.80	13.25	**7.80**	12.65	13.05
Cash operating costs (6),(c)	**13.15**	16.65	13.40	20.50	20.80	**14.40**	23.10	22.20
Firebag start-up costs	**—**	—	8.50	—	—	**2.30**	—	—
Total cash operating costs (7),(c)	**13.15**	16.65	21.90	20.50	20.80	**16.70**	23.10	22.20
Depreciation, depletion and amortization	**5.55**	3.75	6.90	4.60	4.25	**5.30**	5.00	4.90
Total operating costs (8),(c)	**18.70**	20.40	28.80	25.10	25.05	**22.00**	28.10	27.10
(for the period ended)								
Capital employed (h)	**5 550**	5 544	5 450	4 472	4 334			
(for the twelve months ended)								
Return on capital employed (i)	**57.7**	53.8	35.5	22.7	15.1			
Return on capital employed (i) ****	**43.7**	40.5	26.3	16.3	11.2			

QUARTERLY OPERATING SUMMARY (continued)

(unaudited)

	For the quarter ended					Nine months ended		Total year
	Sep 30 2006	June 30 2006	Mar 31 2006	Dec 31 2005	Sep 30 2005	**Sep 30 2006**	Sep 30 2005	Dec 31 2005
NATURAL GAS								
Gross production **								
Natural gas [d]	**191**	189	196	193	200	**192**	189	190
Natural gas liquids [a]	**2.1**	2.6	2.4	2.3	2.2	**2.4**	2.5	2.4
Crude oil [a]	**0.7**	0.9	0.8	0.6	0.7	**0.8**	0.9	0.8
Total gross production [e]	**34.6**	35.1	35.9	35.0	36.3	**35.2**	34.8	34.8
Average sales price [2]								
Natural gas [f]	**6.33**	6.38	9.03	11.66	8.32	**7.16**	7.50	8.57
Natural gas [f] *	**6.13**	6.22	8.75	11.83	8.34	**6.94**	7.47	8.59
Natural gas liquids [b]	**53.11**	60.14	51.75	57.85	58.00	**55.20**	48.52	50.70
Crude oil – Conventional [b]	**84.95**	74.18	60.30	72.60	63.77	**72.79**	62.99	64.85
Net wells drilled								
Conventional – Exploratory ***	**1**	1	5	3	4	**7**	9	12
– Development	**6**	2	4	13	2	**12**	9	22
	7	3	9	16	6	**19**	18	34
(for the period ended)								
Capital employed [h]	**778**	770	590	563	598			
(for the twelve months ended)								
Return on capital employed [i]	**27.9**	30.6	31.7	30.7	22.7			
ENERGY MARKETING AND REFINING – CANADA								
Refined product sales [g]								
Transportation fuels								
Gasoline								
Retail	**4.6**	4.6	4.4	4.5	4.2	**4.5**	4.5	4.5
Other	**3.8**	3.9	3.6	3.3	4.2	**3.8**	4.1	3.9
Jet fuel	**0.7**	0.8	0.7	0.8	0.9	**0.7**	0.9	0.9
Diesel	**3.0**	3.5	3.2	3.4	3.7	**3.2**	3.2	3.3
Total transportation fuel sales	**12.1**	12.8	11.9	12.0	13.0	**12.2**	12.7	12.6
Petrochemicals	**1.0**	0.9	1.2	0.4	0.7	**1.0**	0.7	0.7
Heating oils	**0.4**	0.4	0.6	0.5	0.2	**0.5**	0.4	0.4
Heavy fuel oils	**0.9**	0.7	0.9	0.9	0.8	**0.8**	1.1	1.0
Other	**0.8**	0.6	0.7	0.5	0.9	**0.7**	0.5	0.5
Total refined product sales	**15.2**	15.4	15.3	14.3	15.6	**15.2**	15.4	15.2
Crude oil supply and refining								
Processed at Sarnia refinery [g]	**9.4**	9.9	9.6	10.6	10.7	**9.6**	10.6	10.6
Utilization of refining capacity [i]	**85**	89	86	95	96	**87**	96	95
(for the period ended)								
Capital employed [h]	**847**	490	535	486	547			
(for the twelve months ended)								
Return on capital employed [i]	**21.0**	23.9	11.5	8.1	7.7			
Return on capital employed [i] ****	**11.4**	12.4	6.8	5.2	5.6			

QUARTERLY OPERATING SUMMARY (continued)

(unaudited)

	For the quarter ended					Nine months ended		Total year
	Sep 30 2006	June 30 2006	Mar 31 2006	Dec 31 2005	Sep 30 2005	**Sep 30 2006**	Sep 30 2005	Dec 31 2005
REFINING AND MARKETING – U.S.A.								
Refined product sales (g)								
Transportation fuels								
Gasoline								
Retail	**0.7**	0.7	0.7	0.7	0.7	**0.7**	0.7	0.7
Other	**7.6**	8.0	5.3	7.1	8.9	**6.8**	5.9	6.2
Jet fuel	**1.0**	0.9	0.8	0.9	0.8	**0.9**	0.8	0.8
Diesel	**3.8**	3.8	3.2	3.6	3.9	**3.6**	3.2	3.3
Total transportation fuel sales	**13.1**	13.4	10.0	12.3	14.3	**12.0**	10.6	11.0
Asphalt	**1.6**	1.3	1.0	1.2	1.8	**1.3**	1.8	1.6
Other	**1.5**	1.5	0.3	1.0	1.2	**1.2**	1.1	1.1
Total refined product sales	**16.2**	16.2	11.3	14.5	17.3	**14.5**	13.5	13.7
Crude oil supply and refining								
Processed at Denver refinery (g)	**14.8**	14.6	9.2	13.0	14.9	**12.9**	12.3	12.1
Utilization of refining capacity (i)	**104**	102	65	91	104	**90**	102	98
(for the period ended)								
Capital employed (h)	**810**	340	341	327	354			
(for the twelve months ended)								
Return on capital employed (i)	**44.4**	45.7	42.2	49.4	32.2			
Return on capital employed (i) ****	**25.4**	23.1	22.7	28.9	21.6			

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 production volumes that are processed through the upgrader facilities. 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 all production volumes that are processed through the upgrader facilities.
(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 all production volumes that are processed through the upgrader facilities.
(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.
(7) Total cash operating costs – In-situ bitumen production	Include cash operating costs – Firebag as defined above and cash start-up operating costs. Per barrel amounts are based on in-situ production volumes.
(8) Total operating costs – In-situ bitumen production	Include total cash operating costs – Firebag as defined above and non-cash operating costs. Per barrel amounts are based on in-situ production volumes.

Explanatory Notes

* Excludes the impact of hedging activities.

** Currently all 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) dollars per thousand cubic feet
(g) thousands of cubic metres per day
(h) $ millions
(i) percentage

Metric Conversion

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