![Suncor Energy]

FIRST QUARTER 2009
Report to shareholders for the period ended March 31, 2009

Suncor Energy first quarter results

All financial figures are unaudited and in Canadian dollars unless noted otherwise. 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 2009 first quarter Management's Discussion and Analysis (MD&A). 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.

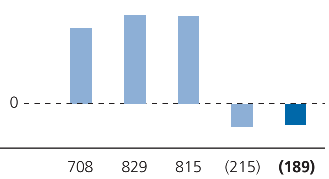
Suncor Energy Inc. recorded a first quarter 2009 net loss of $189 million ($0.20 per common share), compared to net earnings of $708 million ($0.77 per common share) in the first quarter of 2008. Excluding unrealized foreign exchange impacts on the company's U.S. dollar denominated long-term debt, mark-to-market accounting losses on commodity derivatives, and costs related to start-up or deferral of growth projects, first quarter 2009 earnings were $227 million ($0.24 per common share), compared to $805 million ($0.87 per common share) in the first quarter of 2008. Cash flow from operations was $479 million in the first quarter of 2009, compared to $1.161 billion in the first quarter of 2008.

The decrease in earnings was primarily due to lower price realizations, as benchmark commodity prices were significantly weaker in the first quarter of 2009 compared to the same period in 2008. This was partially offset by increased margins in our downstream business segment and reduced oil sands royalty expenses.

"If you back out the effects of accounting impacts from mark-to-market and foreign exchange losses, and the non-structural charges for deferred growth projects, you'll see that from an operational perspective we had a solid quarter, while financial performance was reflective of current economic conditions," said Rick George, president and chief executive officer. "Downstream margins were strong and we reported record quarterly production in the upstream."

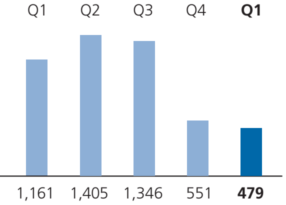
Suncor's total upstream production averaged 314,500 barrels of oil equivalent (boe) per day during the first quarter of 2009, compared to 286,200 boe per day in the first quarter of 2008. Higher production primarily reflects improved operational efficiency at the company's oil sands operations, as well as additional volumes processed on a fee-for-service contract for Petro-Canada, which came into effect on January 1, 2009.

Net Earnings by Quarter
($ millions)



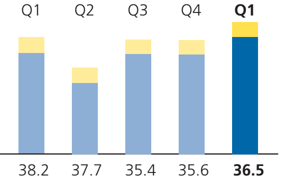
	2008 Q1	2008 Q2	2008 Q3	2008 Q4	**2009 Q1**
	708	829	815	(215)	**(189)**

Cash Flow from Operations by Quarter
($ millions)



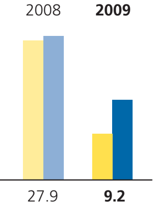
	2008 Q1	2008 Q2	2008 Q3	2008 Q4	**2009 Q1**
	1,161	1,405	1,346	551	**479**

Production
(thousands of barrels of oil equivalent per day)



	2008 Q1	2008 Q2	2008 Q3	2008 Q4	**2009 Q1**
Natural Gas	38.2	37.7	35.4	35.6	**36.5**
Oil Sands	248.0	174.6	245.6	243.8	**278.0**
Total	286.2	212.3	281.0	279.4	**314.5**

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



	2008	**2009**
Return on average shareholders' equity	27.9	**9.2**
Return on capital employed	28.8	**16.0**

Oil sands production contributed an average 278,000 barrels per day (bpd) in the first quarter of 2009, compared to first quarter 2008 production of 248,000 bpd. Natural gas production averaged 219 million cubic feet equivalent (mmcfe) per day in the first quarter of 2009, compared to 229 mmcfe per day in the first quarter of 2008.

"Over the past year, we've made concerted efforts and significant investments targeting improved reliability and increased efficiency at our oil sands operations," said George. "This quarter's production numbers are a real testament to this work and should position us well for good results in 2009, particularly if crude prices hold up."

Oil sands cash operating costs averaged $33.70 per barrel in the first quarter of 2009, compared to $31.55 per barrel during the first quarter of 2008. The increase in cash operating costs per barrel was primarily due to an increase in operational expenses, partially offset by lower energy input costs and reduced third-party bitumen purchases.

Growth update

On March 23, 2009, Suncor and Petro-Canada (TSX:PCA) (NYSE:PCZ) announced that they have agreed to merge the two companies. Upon completion of the transaction, which will require shareholder approval, regulatory approval, as well as a review by the Canadian Competition Bureau, the combined entity is expected to operate corporately and trade under the Suncor name while maintaining the strong brand presence and customer loyalty of Petro-Canada in refined products. The transaction is anticipated to close in the third quarter of 2009.

"This merger creates a made-in-Canada energy leader with the assets, cost structure and financial strength to compete globally," said George, who will continue in the role of president and chief executive officer with the merged company. "The combined portfolio boasts the largest oil sands resource position, a strong Canadian downstream brand, solid conventional exploration and production assets, and low-cost production from Canada's east coast and internationally."

While merger review and approval processes continue, work is ongoing on two significant capital projects at Suncor's oil sands operations. Construction of the Firebag sulphur plant, previously targeted for completion in the second quarter of 2009, is now scheduled for completion early in the third quarter of 2009, with the delay due to the delivery schedule of modules from key vendors. The project cost is expected to exceed the upper end of the original cost range (approximately $375 million) with a final estimated cost in excess of $400 million as a result of the increased cost of major equipment. When complete, the plant is expected to support sulphur emissions reductions for existing and planned in-situ developments.

In addition, the company is nearing completion of its Steepbank extraction plant. This plant, which is targeted for completion in the third quarter of 2009, is expected to provide improved reliability and productivity for the company's oil sands mining and extraction assets.

Suncor does not anticipate an update to growth project plans until after the close of the proposed merger with Petro-Canada. At that time, all capital projects from both companies are expected to be reviewed with a view to directing capital investment toward projects with the strongest near-term cash flow potential, highest anticipated return on capital and lowest risk.

Outlook

Suncor's outlook provides management's targets for 2009 in certain key areas of the company's business. Outlook forecasts are subject to change and do not reflect the proposed merger with Petro-Canada.

	Three Month Actuals Ended March 31, 2009	2009 Full Year Outlook
Oil Sands		
Production (bpd)(1)	**278 000**	300,000 (+5%/−10%)
Sales		
Diesel	**9%**	11%
Sweet	**45%**	39%
Sour	**42%**	48%
Bitumen	**4%**	2%
Realization on crude sales basket(2)	**WTI @ Cushing less Cdn$1.33 per barrel**	WTI @ Cushing less Cdn$4.50 to Cdn$5.50 per barrel
Cash operating costs(3)	**$33.70 per barrel**	$33.00 to $38.00 per barrel
Natural Gas		
Production(4) (mmcf equivalent per day)	**219**	210 (+5%/−5%)
Natural gas	**91%**	92%
Liquids	**9%**	8%

(1) Includes 23,000 bpd in the first three months of 2009 processed by Suncor for Petro-Canada for which Suncor receives a processing fee. Volumes received under this arrangement are not included as purchases for financial statement presentation.

(2) Excludes the impact of hedging activities.

(3) Cash operating cost estimates are based on the following assumptions: (i) production volumes and sales mix as described in the table above; and (ii) a natural gas price of $7.10 per gigajoule ($7.50 per mcf) at AECO. This goal also includes costs incurred for third-party bitumen processing, but does not include costs related to deferral of growth projects. Cash operating costs per barrel are not prescribed by Canadian generally accepted accounting principles (GAAP). This non-GAAP financial measure does not have any standardized meaning and therefore is unlikely to be comparable to similar measures presented by other companies. Suncor includes this non-GAAP financial measure because investors may use this information to analyze operating performance. This information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. See Non-GAAP Financial Measures on page 17.

(4) Production target includes natural gas liquids (NGL) and crude oil converted into mmcf equivalent at a ratio of one barrel of NGL/crude oil: six thousand cubic feet of natural gas. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This mmcf equivalent may be misleading, particularly if used in isolation.

The 2009 outlook is based on Suncor's current estimates, projections, assumptions and year-to-date performance for the 2009 fiscal year and is subject to change. Assumptions are based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be relevant. Assumptions of the 2009 outlook include implementing reliability and operational efficiency initiatives which we expect to minimize unplanned maintenance in 2009.

Factors that could potentially impact Suncor's operations and financial performance in 2009 include:

- Bitumen supply. Ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage and in-situ reservoir performance could impact 2009 production targets. Production could also be impacted by the availability of third-party bitumen.
- Performance of recently commissioned upgrading facilities. Production rates while new equipment is being lined out are difficult to predict and can be impacted by unplanned maintenance.
- Unplanned maintenance. Production estimates could be impacted if unplanned work is required at any of our mining, production, upgrading, refining or pipeline assets.
- Crude oil hedges. Suncor has hedging agreements for approximately 60% of targeted production in 2009 and for 50,000 bpd in 2010. For further details of our hedging activities, see page 12 in Suncor's first quarter MD&A.

For additional information on risk factors that could cause actual results to differ, please see page 19 of Suncor's 2008 Annual Report.

Management's Discussion and Analysis

April 22, 2009

This Management's Discussion and Analysis (MD&A) contains forward-looking information based on certain expectations, estimates, projections and assumptions. This information is subject to a number of risks and uncertainties, many of which are beyond the company's control. Users of this information are cautioned that actual results may differ materially. For information on material risk factors and assumptions underlying our forward-looking information, see page 19.

This MD&A should be read in conjunction with our March 31, 2009 unaudited interim consolidated financial statements and notes. Readers should also refer to our MD&A on pages 6 to 42 of our 2008 Annual Report and to our Annual Information Form (AIF) dated March 2, 2009. All financial information is reported in Canadian dollars (Cdn$) and in accordance with Canadian generally accepted accounting principles (GAAP) unless noted otherwise. The financial measures: cash flow from operations, return on capital employed (ROCE) and cash and total operating costs per barrel referred to in this MD&A are not prescribed by GAAP and are outlined and reconciled in Non-GAAP Financial Measures on page 40 of our 2008 Annual Report, and page 17 of this MD&A.

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

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

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

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

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

The information in this MD&A does not assume the completion of the merger between Suncor and Petro-Canada, and forward-looking information is presented for Suncor on a stand alone basis.

Selected Financial Information

Industry Indicators

(average for the period)	Three months ended March 31 **2009**	2008
West Texas Intermediate (WTI) crude oil US$/barrel at Cushing	**43.10**	97.90
Canadian 0.3% par crude oil Cdn$/barrel at Edmonton	**50.10**	98.25
Light/heavy crude oil differential US$/barrel WTI at Cushing less Western Canadian Select at Hardisty	**8.95**	21.55
Natural Gas US$/mcf at Henry Hub	**4.75**	8.10
Natural Gas (Alberta spot) Cdn$/mcf at AECO	**5.65**	7.15
New York Harbour 3-2-1 crack (1) US$/barrel	**9.85**	8.75
Exchange rate: US$/Cdn$	**0.80**	1.00

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

Outstanding Share Data (at March 31, 2009)

Common shares	936 687 415
Common share options – total	46 619 637
Common share options – exercisable	26 344 268

Summary of Quarterly Results

	2009	2008				2007		
	Three months ended	Three months ended				Three months ended		
($ millions, except per share)	**Mar 31**	Dec 31	Sept 30	June 30	Mar 31	Dec 31	Sept 30	June 30
Revenues	**4 814**	7 196	8 946	7 959	5 988	5 185	4 802	4 525
Net earnings (loss)	**(189)**	(215)	815	829	708	1 042	627	738
Net earnings (loss) per common share								
Basic	**(0.20)**	(0.24)	0.87	0.89	0.77	1.12	0.68	0.80
Diluted	**(0.20)**	(0.24)	0.86	0.87	0.75	1.10	0.66	0.78

Analysis of Consolidated Statements of Earnings and Cash Flows

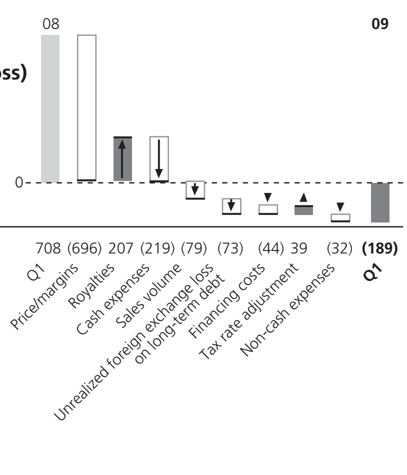
Net loss for the first quarter of 2009 was $189 million, compared to net earnings of $708 million for the first quarter of 2008. Excluding unrealized foreign exchange impacts on the company's U.S. dollar denominated long-term debt, mark-to-market accounting losses on commodity derivatives, and costs related to start-up or deferral of growth projects, first quarter 2009 earnings were $227 million ($0.24 per common share), compared to $805 million ($0.87 per common share) in the first quarter of 2008.

The decrease in earnings was primarily due to lower price realizations, as benchmark commodity prices were significantly weaker in the first quarter of 2009 compared to the same period in 2008. This was partially offset by increased margins in our downstream business segment and reduced oil sands royalty expenses.

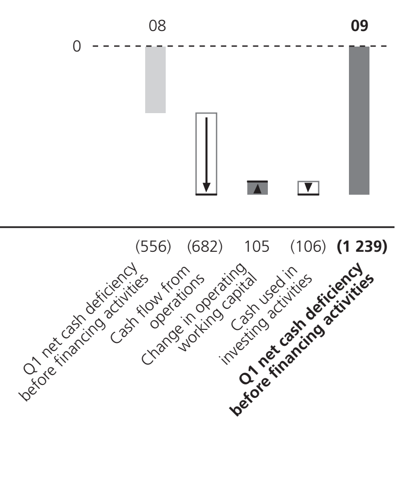
Cash flow from operations in the first quarter of 2009 was $479 million, compared to $1.161 billion in the same period of 2008. The decrease was due primarily to the same factors that impacted earnings.

Our effective tax rate for the first quarter of 2009 was 22%, compared to 30% in the first quarter of 2008. The lower effective tax rate in the first quarter of 2009 is primarily a result of our losses in the quarter. During the first three months of 2009, we recorded $90 million in current income tax expense compared to $156 million in the first three months of 2008 (see page 10 for a more detailed discussion).

Bridge Analysis of Consolidated Net Earnings (Loss)
($ millions)



Bridge Analysis of Consolidated Net Cash Flow
($ millions)



Net Earnings Components

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

($ millions, after-tax)	Three months ended March 31 **2009**	2008
Earnings before the following items:	**227**	805
Mark-to-market accounting loss on commodity derivatives	**(132)**	(17)
Costs related to deferral of growth projects	**(125)**	—
Unrealized foreign exchange loss on U.S. dollar denominated long-term debt	**(148)**	(75)
Project start-up costs	**(11)**	(5)
Net earnings as reported	**(189)**	708

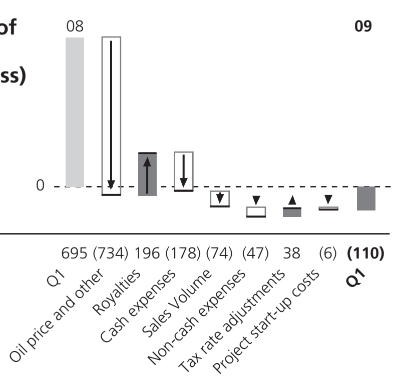
Analysis of Segmented Earnings and Cash Flows

Oil Sands

Oil sands recorded a net loss of $110 million in the first quarter of 2009, compared with net earnings of $695 million in the first quarter of 2008. Excluding the impact of mark-to-market accounting losses on commodity derivatives, and costs related to start-up or deferral of growth projects, earnings for the first quarter of 2009 were $158 million, compared to $717 million in the first quarter of 2008. Earnings decreased primarily as a result of lower average price realizations for oil sands crude products, partially offset by reduced royalty expenses.

The decrease in price realizations reflects significantly lower benchmark WTI crude oil prices and a decreased premium to WTI for our sweet crude blends, partially offset by the weaker Canadian dollar and a smaller discount to WTI for our sour crude blends.

Bridge Analysis of Oil Sands Net Earnings (Loss)
($ millions)



Purchases of crude oil and products were $62 million in the first quarter of 2009, compared to $47 million in the first quarter of 2008. The increase was primarily a result of purchases of product to facilitate bitumen sales. This increase was partially offset by a reduction in purchases of third-party bitumen, which had been higher in the first quarter of 2008 as a result of regulatory requirements that capped our in-situ production.

Operating expenses were $909 million in the first quarter of 2009, compared to $717 million in the first quarter of 2008. The increase was due primarily to costs resulting from deferring growth projects and putting them into "safe mode" as a result of current economic conditions. Safe mode is defined as the costs of deferring the projects and keeping the equipment and facilities in a safe manner in order to expedite remobilization. In addition, operating expenses increased partly due to a combination of higher maintenance expenses which resulted from efforts to improve reliability and an increase in size of our mining fleet, as well as increased employee costs and higher contract mining costs. These factors were partially offset by lower energy input costs.

Depreciation, depletion and amortization (DD&A) expense was $183 million in the first quarter of 2009, compared to $129 million during the same period in 2008. The increase resulted from continued growth in the depreciable cost base for our oil sands facilities.

Alberta Crown royalty expense was $8 million in the first quarter of 2009, compared to $282 million in the first quarter of 2008. The lower expense was due to a significant decrease in price realizations in the quarter, causing royalty-eligible operating costs and capital expenditures (C) to exceed revenues related to bitumen less related transportation costs (R). As a result, royalties were paid on 1% of R instead of 25% of R minus C. In addition, effective January 1, 2009, revenues from our base mine operations are now based on bitumen values (previously based on synthetic crude oil) with a corresponding exclusion of upgrading costs from royalty eligibility. For a further discussion of Crown royalties, see page 8.

Cash flow from operations was $179 million in the first quarter of 2009, compared to $910 million in the first quarter of 2008. Excluding the impact of DD&A, the decrease was due primarily to the same factors that impacted earnings.

Oil sands production was 278,000 barrels per day (bpd) in the first quarter of 2009, compared to 248,000 bpd during the first quarter of 2008. In addition to Suncor's proprietary production of sweet and sour synthetic crude oil, diesel and non-upgraded bitumen sold directly to the market, which had been lower in the first quarter of 2008 primarily due to a regulatory cap on Firebag production, reported production also includes products derived from bitumen received from Petro-Canada for processing on a fee-for-service basis. This processing arrangement with Petro-Canada became effective on January 1, 2009.

Sales volumes during the first quarter of 2009 averaged 243,400 bpd, compared with 245,100 bpd during the first quarter of 2008. With improved operational reliability, the proportion of higher value diesel fuel and sweet crude products increased to 54% of total sales volumes in the first quarter of 2009, compared to 51% in the first quarter of 2008.

The average price realization for oil sands crude products decreased to $57.97 per barrel in the first quarter of 2009, compared to $96.16 per barrel in the first quarter of 2008. A significant decrease in the average benchmark WTI crude oil price of about 56% and a decreased premium to WTI on our sweet crude blends were partially offset by a smaller discount to WTI for our sour crude blends and by a change in sales mix which reflected a larger portion of higher priced sweet products. In addition, the weaker Canadian dollar had a positive impact on our average price realization, as we received higher revenues for our production sold based on U.S. dollar benchmark prices.

During the first quarter of 2009, cash operating costs averaged $33.70 per barrel, compared to $31.55 per barrel during the first quarter of 2008. The increase in cash operating costs per barrel was primarily due to an increase in operational expenses, partially offset by lower energy input costs and reduced third-party bitumen purchases. Cash operating costs per barrel does not include costs related to deferral of growth projects. Refer to page 17 for further details on cash operating costs as a non-GAAP financial measure, including the calculation and reconciliation to GAAP measures.

Oil Sands Growth Update

Construction of the Firebag sulphur plant, previously targeted for completion in the second quarter of 2009, is now scheduled for completion early in the third quarter of 2009, with the delay due to the delivery schedule of modules from key vendors. The project cost is expected to exceed the upper end of the original cost range (approximately $375 million) with a final estimated cost in excess of $400 million as a result of the increased cost of major equipment. When complete, the plant is expected to support sulphur emissions reductions for existing and planned in-situ developments.

In addition, the company is nearing completion of its Steepbank extraction plant. Located on the east side of the Athabasca River, this plant, which is targeted for completion in the third quarter of 2009, is expected to provide improved reliability and productivity for the company's oil sands assets.

In response to current market uncertainty, we announced an update to our Voyageur program schedule on January 20, 2009. A revised capital budget has deferred the company's growth projects. We do not anticipate an update to growth project plans until after the close of the proposed merger with Petro-Canada. At that time, all capital projects from both companies are expected to be reviewed with a view to directing capital investment toward projects with the strongest near-term cash flow potential, highest anticipated return on capital and lowest risk.

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

As a result of placing the company's projects into safe mode, pretax costs of $175 million were incurred in the first quarter of 2009. These costs are expected to total between $400 million and $500 million on a pretax basis in 2009.

Oil Sands Crown Royalties

For a description of the Alberta Crown royalty regimes in effect for our oil sands operations, see page 15 of our 2008 Annual Report.

The following table sets forth our estimates of royalties in the years 2009 through 2013, and certain assumptions on which we have based our estimates.

WTI Price/bbl US$	**40**	**50**	**60**
Natural gas (Alberta spot) Cdn$/mcf at AECO	6.50	7.00	7.50
Light/heavy oil differential of WTI at Cushing less Maya at the U.S. Gulf Coast US$	8.00	9.00	11.00
Differential of Maya at the U.S. Gulf Coast less Western Canadian Select at Hardisty, Alberta US$	7.00	7.00	7.00
US$/Cdn$ exchange rate	0.75	0.80	0.85
Crown Royalty Expense (based on percentage of total oil sands revenue)%			
2009 – Bitumen (mining old rates – 25% and 1% min; in-situ new rates[(1)])	1	1	1
2010 to 2013 – Bitumen (new rates – with limits for mining only[(1)])	1	1	1-5

(1) Oil Sands royalty rates – see page 15 of our 2008 Annual Report.

The previous table contains forward-looking information and users of this information are cautioned that actual Crown royalty expense may vary from the percentages disclosed in the table. The percentages disclosed in the table were developed using the following assumptions: current agreements with the government of Alberta, royalty rates and other changes enacted effective January 1, 2009 by the government of Alberta, current forecasts of production, capital and operating costs, and the forward estimates of commodity prices and exchange rates described in the table.

The following material risk factors could cause actual royalty rates to differ materially from the rates contained in the foregoing table:

(i) The government has enacted new Bitumen Valuation Methodology regulations as part of the implementation of the New Royalty Framework effective January 1, 2009. While the interim bitumen valuation methodology in 2009 has been enacted, the permanent valuation methodology for 2010 has yet to be finalized. For our mining operations, the bitumen valuation methodology is based on our interpretation of the terms of our January 2008 Royalty Amending Agreement. That agreement places certain limitations on the bitumen valuation methodology as recently enacted. If our interpretations of these limitations changes, this could impact the royalties payable to the Crown.

(ii) The government enacted new Allowed Cost regulations as part of the implementation of the New Royalty Framework effective January 1, 2009. Further clarification of some Allowed Cost business rules is still expected. The terms of our January 2008 Royalty Amending Agreement shelter us through 2015 from the impact of many of these changes for our mining operations. In addition, since our in-situ operations are forecast to remain in pre-payout royalty for the near term, the changes in the Allowed Cost regulations will not have a near term impact on our payment of royalties. However, potential changes and the interpretation of the Allowed Cost regulations could, over time, have a significant impact on our calculation of royalties.

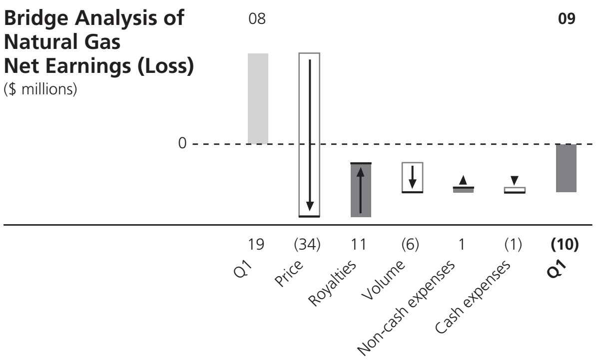
(iii) Changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each oil sands project; changes resulting from regulatory audits of prior year filings; further changes to applicable royalty regimes by the government of Alberta; changes in other legislation and the occurrence of unexpected events all have the potential to have an impact on royalties payable to the Crown.

For further information on risk factors related to royalty rates, please see page 42 of Suncor's AIF dated March 2, 2009.

Natural Gas

Our natural gas business recorded a net loss of $10 million in the first quarter of 2009, compared with net earnings of $19 million during the first quarter of 2008. The net loss was primarily the result of lower revenues that resulted from lower commodity prices and decreased production. These factors were partially offset by decreased royalties resulting from the lower revenues.

Bridge Analysis of Natural Gas Net Earnings (Loss)
($ millions)



Cash flow from operations for the first quarter of 2009 was $55 million, compared to $82 million in the first quarter of 2008. The decrease was primarily due to the same factors affecting net earnings.

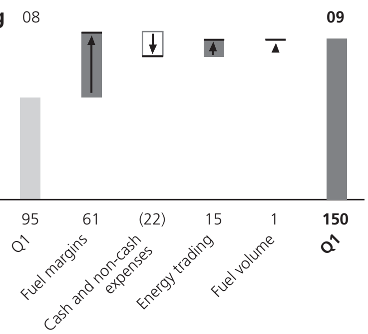
Natural gas and liquids production in the first quarter of 2009 was 219 million cubic feet equivalent (mmcfe) per day, compared to 229 mmcfe per day in the first quarter of 2008. The lower production compared to the prior year was primarily due to natural reservoir production declines. Our 2009 planned production of 210 mmcfe/day (+5%/−5%) offsets Suncor's projected purchases for internal consumption at our oil sands operations.

Realized natural gas prices in the first quarter of 2009 were $5.63 per thousand cubic feet (mcf), compared to $7.30 per mcf in the first quarter of 2008, reflecting lower benchmark prices.

Refining and Marketing

Refining and marketing recorded 2009 first quarter net earnings of $150 million, compared to net earnings of $95 million in the first quarter of 2008. The increase in net earnings primarily resulted from higher gasoline and asphalt margins. Earnings were also positively impacted by an increase in refined product sales over the first quarter of 2008 (when production was negatively impacted by the loss of third-party hydrogen supply at our Sarnia refinery and planned maintenance at our Commerce City refinery).

Bridge Analysis of Refining and Marketing Net Earnings
($ millions)



Energy trading activities resulted in net pretax earnings of $49 million in the first quarter of 2009, compared to $28 million in the first quarter of 2008. This was due to an increase in earnings on our crude trading activities.

Cash flow from operations was $255 million in the first quarter of 2009, compared to $190 million in the first quarter of 2008. Cash flow from operations increased primarily due to the same factors affecting net earnings.

The observed performance of our Sarnia refinery in 2008, after completion of our diesel desulphurization and oil sands integration project in 2007, has enabled us to upwardly revise our nameplate capacity to 85,000 bpd from the previously disclosed 70,000 bpd. Effective January 1, 2009, refinery utilization has been calculated using the new capacity. The Commerce City refining capacity has also been increased to 93,000 bpd from 90,000 bpd effective January 1, 2009. During the first quarter of 2009, average daily crude input was 160,400 bpd (90% utilization) compared to 144,700 bpd (90% utilization) in the first quarter of 2008. The average daily crude input was lower in the first quarter of 2008 due to the loss of third-party hydrogen supply at the Sarnia refinery and planned maintenance at the Commerce City refinery.

Corporate and Eliminations

After-tax net corporate expense was $219 million in the first quarter of 2009, compared to $101 million in the first quarter of 2008. Excluding the impact of group elimination entries, after-tax net corporate expense was $208 million in the first quarter of 2009 ($73 million in the first quarter of 2008). Expense increased mainly due to larger unrealized foreign exchange losses on our U.S. dollar denominated long-term debt, as the amount by which the U.S. dollar strengthened against the Canadian dollar was greater during the first quarter of 2009. After-tax unrealized foreign exchange losses on U.S. dollar denominated long-term debt were $148 million in the first quarter of 2009 compared to losses of $75 million in the first quarter of 2008. Net corporate expense also increased due to higher net interest expense in the first quarter of 2009, as the company expensed $64 million of interest costs that can no longer be capitalized while the growth projects are in safe mode.

Breakdown of Net Corporate Expense

Three months ended March 31 ($ millions)	**2009**	2008
Corporate expense	**(208)**	(73)
Group eliminations	**(11)**	(28)
Total	**(219)**	(101)

Cash used in operations was $10 million in the first quarter of 2009, compared to $21 million in the first quarter of 2008.

Cash Income Taxes

We estimate we will have cash income taxes of approximately $350 million to $450 million during 2009. Cash income taxes are sensitive to crude oil and natural gas commodity price volatility and the timing of deductibility of capital expenditures for income tax purposes, among other things. This estimate is based on the following assumptions: current forecasts of production, capital and operating costs and the commodity prices and exchange rates described in the royalty estimate table on page 8, assuming there are no changes to the current income tax regime. Our outlook on cash income tax is a forward looking statement and users of this information are cautioned that actual cash income taxes may vary materially from our outlook.

Analysis of Financial Condition and Liquidity

The current economic environment has impacted Suncor through both reduced price realizations and higher interest rates on future borrowings. As a result of the current market uncertainty, on January 20, 2009, we announced a reduction to our 2009 planned capital spending.

Our capital resources consist primarily of cash flow from operations and available lines of credit. We believe we will have the capital resources to fund our 2009 capital spending program of $3 billion and to meet current working capital requirements through cash flow from operations and our committed credit facilities, assuming production of 300,000 bpd and a WTI price of US$40/bbl. Our cash flow from operations depends on a number of factors, including commodity prices, production/sales levels, downstream margins, operating expenses, taxes, royalties, and US$/Cdn$ exchange rates. If additional capital is required, we believe adequate additional financing will be available in the debt capital markets at commercial terms and rates (which are currently higher than in 2008).

To provide an additional element of security to our cash flow from operations, we have entered into crude oil hedge contracts that provide us with an equivalent WTI floor price of about US$53.50 for approximately 180,000 bpd of production in 2009. For the full year 2010, we have crude oil hedges for approximately 50,000 bpd at an equivalent WTI floor price of US$50.00 per barrel and a ceiling price of approximately US$68.00 per barrel.

In addition, we are closely managing our operational spending, including a freeze on discretionary salary increases as well as implementation of a variety of cost-cutting measures throughout the company.

Management of debt levels continues to be a priority given our long-term growth plans. We believe a phased and flexible approach to existing and future growth projects should assist us in maintaining our ability to manage project costs and debt levels. At March 31, 2009, our net debt (short and long-term debt less cash and cash equivalents) was $8.638 billion, compared to $7.226 billion at December 31, 2008. The increase in debt levels was primarily a result of capital expenditures during the quarter. Undrawn lines of credit at March 31, 2009 were approximately $1.9 billion.

Interest expense on debt continues to be influenced by the composition of our debt portfolio, and we are currently benefiting from short-term floating interest rates which remain at historically low levels. To manage fixed versus floating rate exposure, we have entered into interest rate swaps with investment grade counterparties. At March 31, 2009, we had $200 million of fixed-rate to floating-rate interest swaps (December 31, 2008 – $200 million).

We are subject to financial and operating covenants related to our public market and bank debt. Failure to meet the terms of one or more of these covenants may constitute an Event of Default as defined in the respective debt agreements, potentially resulting in accelerated repayment of one or more of the debt obligations. We are in compliance with our financial covenant that requires consolidated debt to not be more than 65% of our total capitalization. At March 31, 2009, our consolidated debt to total capitalization was 39% (where consolidated debt is short-term debt plus long-term debt, and total capitalization is consolidated debt plus shareholders' equity). We are also in compliance with all operating covenants.

Excluding cash and cash equivalents, short-term debt and future income taxes, Suncor had an operating working capital deficiency of $233 million at the end of the first quarter of 2009, compared to a deficiency of $347 million at the end of the first quarter of 2008. The reduction in the deficiency was due primarily to an increase in our income taxes receivable account related to the timing of installment payments.

The preceding paragraphs contain forward-looking information regarding our liquidity and capital resources and users of this information are cautioned that our actual liquidity and capital resources may vary from our expectations.

Significant Capital Project Update

With the deferral of the company's growth projects and the reduction of capital spending announced on January 20, 2009, construction on the Voyageur upgrader and Firebag in-situ facilities is being wound down and the projects placed into safe mode pending resumption of expansion work. At this time, construction restart and completion targets for these projects, and start up and completion targets for other expansion projects, have not been determined. We do not anticipate any update to our growth project plans until after the completion of the proposed merger with Petro-Canada. For a summary of progress on the projects placed into safe mode, please see page 14 of our 2008 Annual Report.

A summary of the progress on our significant projects currently under construction is provided below. All projects listed below have received Board of Director approval. The estimates and target completion dates do not include project commissioning and start-up.

Project	Plan	Cost Estimate $ millions (1)	Estimate % Accuracy (1)	Spent to date	% complete Overall engineering	% complete Construction	Target completion date
Firebag sulphur plant(2)	Support emission abatement plan at Firebag; capacity to support Stages 1-6	404	+5/–1	320	98	60	Q3 2009
Steepbank extraction plant	New location and technologies aimed at improving operational performance	850	+10/–10	795	100	80	Q3 2009

(1) Cost estimates and estimate accuracy reflect budgets approved or expected to be approved by Suncor's Board of Directors.

(2) Cost estimate revised to $404 million +5/ – 1% (previously $340 million +10/ – 10%) and target completion date revised to Q3 2009 (previously Q2 2009).

The preceding paragraphs and table contain forward-looking information and users of this information are cautioned that the actual timing, amount of the final capital expenditures and expected results, including target completion dates, for each of these projects may vary from the plans disclosed in the table. For a list of the material risk factors that could cause actual timing, amount of the final capital expenditures and expected results to differ materially from those contained in the previous table, please see page 19 of our 2008 Annual Report. For additional information on risks, uncertainties and other factors that could cause actual results to differ, please see page 19.

The material factors used to develop target completion dates and cost estimates are: current capital spending plans, the current status of procurement, design and engineering phases of the project; updates from third parties on delivery of goods and services associated with the project; and estimates from major projects teams on completion of future phases of the project. We have assumed that commitments from third parties will be honoured and that material delays and increased costs related to the risk factors referred to above will not be encountered.

Derivative Financial Instruments

We periodically enter into derivative contracts such as forwards, futures, swaps, options and costless collars to hedge against the potential adverse impact of changing market prices due to changes in the underlying indices.

We have estimated fair values of derivative financial instruments by assessing available market information and appropriate valuation methodologies based on industry-accepted third-party models; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

Derivative contracts are required to be recorded on the balance sheet at fair value. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income and are recognized in net earnings when the hedged item is recognized. If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk are recognized in net earnings. Ineffective portions of changes in the fair value of hedging instruments are recognized in net earnings immediately for both cash flow and fair value hedges.

Suncor also periodically enters into derivative financial instruments that either do not qualify for hedge accounting treatment or that Suncor has not elected to document as part of a qualifying hedge relationship. These financial instruments are accounted for using the mark-to-market method, with any changes in fair value immediately recognized in earnings.

Commodity and Treasury Hedging Activities

The company has hedged a portion of its forecasted U.S. dollar denominated sales subject to U.S. dollar West Texas Intermediate (WTI) price risk. In February 2009, we entered into crude oil hedges for approximately 125,000 barrels per day (bpd) of production from February 1 through December 31, 2009. These volumes are in addition to previously reported options to sell 55,000 bpd at an equivalent WTI floor price of US$60.00 per barrel from January 1 to December 31, 2009. The combination of the previous options and new fixed-price hedges provide Suncor with an equivalent WTI floor price of about US$53.50 for approximately 180,000 bpd of production in 2009.

For the full year 2010, we have entered into crude oil hedges for approximately 50,000 bpd at an equivalent WTI floor price of US$50.00 per barrel and a ceiling price of approximately US$68.00 per barrel. This program replaces previously reported 2010 options to sell 55,000 bpd at an equivalent WTI floor price of US$60.00, which was effectively exited by selling similar contracts for gross pretax proceeds to Suncor of approximately $250 million.

These contracts have not been designated for hedge accounting, and as such, any fair value changes on these contracts are recognized in net earnings each period.

In addition to our strategic crude oil hedging program, Suncor uses derivative contracts to hedge risks related to purchases and sales of natural gas and refined products, and to hedge risks specific to individual transactions.

Settlement of our commodity hedging contracts results in cash receipts or payments for the difference between the derivative contract and market rates for the applicable volumes hedged during the contract term. For accounting purposes, amounts received or paid on settlement are recorded as part of the related hedged sales or purchase transactions.

We periodically enter into interest rate swap contracts as part of our strategy to manage exposure to interest rates. The interest rate swap contracts involve an exchange of floating rate and fixed rate interest payments between ourselves and investment grade counterparties. The differentials on the exchange of periodic interest payments are recognized as an adjustment to interest expense. We have recently entered into foreign exchange forward contracts to fix the Canadian dollar value we will receive on future sales of crude oil. Amounts received or paid on settlement will be recorded as part of the related hedged sales transactions.

The company also manages variability in market interest rates and foreign exchange rates during periods of debt issuance through the use of interest rate swaps and foreign exchange forward contracts.

Significant commodity contracts outstanding at March 31, 2009 were as follows:

Crude oil	Quantity (bpd)	Price (US$/bbl) (1)	Revenue Hedged (Cdn$ millions) (2)	Hedge Period (3)
Purchased puts	55 000	60.00	1 144	2009
Fixed price	126 575	50.68	2 223	2009
Purchased puts	55 000	60.00	1 518	2010
Sold puts	54 753	60.00	(1 511)	2010
Collars – floor	50 041	50.00	1 151	2010
Collars – cap	49 986	68.06	1 565	2010

(1) Price for crude oil contracts is US$ WTI per barrel at Cushing, Oklahoma.

(2) The revenue hedged is translated to Cdn$ at the March 31, 2009 month-end rate and is subject to change as the US$/Cdn$ exchange rate fluctuates during the hedge period.

(3) Original hedge term is for full year.

The net earnings impact associated with our commodity and treasury hedging activities in the first quarter of 2009 was a pretax loss of $220 million, compared to a pretax loss of $13 million in the first quarter of 2008.

A reconciliation of changes in accumulated other comprehensive income (AOCI) attributable to derivative hedging activities for the three month periods ending March 31 is as follows:

($ millions)	**2009**	2008
AOCI attributable to derivative hedging activities, beginning of the period, net of income taxes of $5 (2008 – $4)	**13**	13
Current period net changes arising from cash flow hedges, net of income taxes of $nil (2008 – $2)	**—**	(7)
Net unrealized hedging losses (gains) at the beginning of the year reclassified to earnings during the period, net of income taxes of $nil (2008 – $nil)	**2**	1
AOCI attributable to derivative hedging activities, at March 31, net of income taxes of $5 (2008 – $2)	**15**	7

Energy Trading Activities

In addition to derivative contracts used for hedging activities, Suncor uses physical and financial energy derivatives to earn trading revenues. These energy contracts are comprised of crude oil, natural gas and refined products derivative contracts. The results of these trading activities are reported as energy trading revenues and expenses in the Consolidated Statements of Earnings and Comprehensive Income. The net pretax earnings associated with our energy trading activities in the first quarter of 2009 were $49 million (2008 – $28 million).

Fair Value of Derivative Financial Instruments

The fair value of derivative financial instruments is the estimated amount we would receive (pay) to terminate the contracts. Such amounts, which also represent the unrealized gain (loss) on the contracts, were as follows:

($ millions)	March 31 2009	December 31 2008
Derivative financial instruments accounted for as hedges		
Assets	**21**	24
Liabilities	**(8)**	(13)
Derivative financial instruments not accounted for as hedges		
Assets	**462**	635
Liabilities	**(497)**	(14)
Net derivative financial instruments	**(22)**	632

Risks Associated with Derivative Financial Instruments

Our strategic crude oil hedging program is subject to periodic management reviews to determine appropriate hedge requirements in light of our tolerance for exposure to market volatility as well as the need for stable cash flow to finance future growth.

We may be exposed to certain losses in the event that the counterparties to derivative financial instruments are unable to meet the terms of the contracts. We minimize this risk by entering into agreements with investment grade counterparties. Risk is also minimized through regular management review of the potential exposure to and credit ratings of such counterparties. Our exposure is limited to those counterparties holding derivative contracts with net positive fair values at the reporting date.

Energy marketing and trading activities, by their nature, can result in volatile and large positive or negative fluctuations in earnings. A separate risk management function reviews and monitors practices and policies and provides independent verification and valuation of these activities.

Environmental Regulation and Risk

At our in-situ operations, high emissions in 2007 resulted in intervention by both Alberta Environment and the Alberta Energy and Utilities Board (now known as the Energy Resources Conservation Board). The production cap, which limited production to 42,000 bpd, was lifted in the third quarter of 2008. On April 4, 2009, Suncor appeared in court on charges related to the Firebag emissions control facilities as well as waste water discharge exceedance at its Millennium Lodge residential camp. The company was fined $675,000 and $175,000, respectively, for which Suncor, the Crown and Compass Canada (the contractor involved in the waste water discharge) have submitted creative penalty proposals that would see nearly 50% of the fine directed towards environmental and conservation education programs.

In March 2009, in accordance with the Alberta government's Climate Change and Emissions Management Act, Suncor filed its compliance report for the January 1 to December 31, 2008 period. Compliance costs of approximately $5 million were met through emission performance credits generated at our cogeneration facilities, internally generated wind energy offset credits, and purchasing external offset credits.

In 2007, the Canadian federal government introduced the Clean Air Act regulatory framework, which is expected to regulate both greenhouse gas emissions and air pollutants from industrial emitters. Suncor has been engaging in the ongoing consultations on this framework. The financial impact of this proposed legislation will be dependent on the details of Clean Air Act regulations, which were expected to be released by the end of 2008. Now that the Canadian federal government has committed to implement a North American cap and trade system with the United States, it is not certain that the Clean Air Act framework, in its current form, will be implemented.

The Ontario provincial and Colorado state governments are also in various stages of developing greenhouse gas management legislation and regulation. At this time, no such legislation has been tabled in these jurisdictions and any potential impacts are unknown.

There remains uncertainty around the outcome and impacts of climate change and other environmental regulations. Depending on the scope of any final regulations, these impacts may have an adverse effect on our operational and financial results in the future. We continue to actively work to mitigate our environmental impact, investing in renewable energy such as wind power and biofuels, accelerating land reclamation, installing new emission abatement equipment and investigating other mitigation opportunities such as carbon capture and sequestration.

In early 2009, a number of frameworks, proposals and directives were issued by the various provincial regulators that oversee oil sands development. These relate to tailings management, water use and land use to name a few. While the financial implications of such directives are yet unknown, Suncor is committed to working with the appropriate regulatory bodies as they develop new policies and to fully comply with all existing and new regulations and directives as they apply to the company's operations.

Control Environment

Based on their evaluation as of March 31, 2009, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the United States Securities Exchange Act of 1934 (the Exchange Act)) are effective to ensure that information required to be disclosed by us in reports that we file or submit to Canadian and U.S. securities authorities is recorded, processed, summarized and reported within the time periods specified in Canadian and U.S. securities laws. In addition, as of March 31, 2009, there were no changes in our internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) – 15d-15(f)) that occurred during the three month period ended March 31, 2009 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.

Based on their inherent limitations, disclosure control and procedures and internal controls over financial reporting may not prevent or detect misstatements and even those options determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Change in Accounting Policies

(a) Goodwill and Intangible Assets

On January 1, 2009, the company retroactively adopted Canadian Institute of Chartered Accountants (CICA) Handbook section 3064 "Goodwill and Intangible Assets". This new standard replaces section 3062 "Goodwill and Other Intangible Assets" and section 3450 "Research and Development Costs", and focuses on the criteria for asset recognition in the financial statements, including those internally developed. The impact of adopting this standard resulted in a change in the classification of our deferred maintenance shutdown costs that had previously been classified within other assets and amortized over the period to the next shutdown, as follows:

Change in Consolidated Balance Sheets

($ millions, increase/(decrease))	**As at March 31 2009**	As at December 31 2008
Property, plant and equipment, net	**522**	566
Other assets	**(522)**	(566)

(b) International Financial Reporting Standards

In February 2008, the Accounting Standards Board confirmed that International Financial Reporting Standards (IFRS) will replace Canadian GAAP in 2011 for publicly accountable enterprises. While IFRS uses a conceptual framework similar to Canadian GAAP there are significant differences in accounting policies that must be evaluated.

The company's IFRS conversion project began in 2008. Please see the following table for certain elements of the transition plan, and an assessment of progress. Note that the project team is working through a detailed project plan and that certain project activities and milestones could change. Further, changes in regulation or economic conditions at the date of the changeover or through the project could result in changes to the project activities communicated in the following chart.

IFRS Conversion Project

Key Activity	Key Milestones	Status
Financial Statement Preparation: – Identify differences in Canadian GAAP/IFRS accounting policies. – Select Suncor's ongoing IFRS policies. – Develop financial statement format. – Quantify effects of change in initial IFRS disclosure and 2010 financial statements.	Senior management and steering committee sign-off for all key IFRS accounting policy choices to occur during 2009. Develop draft financial statement format to occur during 2009.	Completed the IFRS diagnostic during 2008, which involved a high level review of the major differences between Canadian GAAP and IFRS. In-depth analysis of issues and accounting policy choices is progressing.
Training: Define and introduce appropriate level of IFRS expertise for each of the following: – Financial reporting group and operating accounting staff. – Suncor management. – Audit Committee.	Financial reporting group and operating accounting staff training to occur during 2009 as needed. Additional training will occur throughout the project as needs are reassessed. Suncor management and Audit Committee training scheduled to occur during 2009.	Project team expert resources have been identified to provide insights and training. Training for project team members is occurring throughout the project.
Infrastructure: Confirm that business processes and systems are IFRS compliant, including: – Program upgrades/changes. – Gathering data for disclosures.	Confirm that systems can address 2010 dual reporting requirements by 2009 and identify areas requiring change. Confirmation that business processes and systems are IFRS compliant will occur throughout the project.	In depth analysis of IT dual reporting solutions is underway. Currently reviewing options to address business process changes and dual reporting during 2010.
Control Environment: – For all accounting policy changes identified, assess control design and effectiveness implications. – Implement appropriate changes.	All key control and design effectiveness implications are being assessed as part of the key IFRS differences and accounting policy choices through 2009.	Analysis of control issues is underway in conjunction with review of accounting issues and policies.
External Communications: Assess the effects of key IFRS related accounting policy and financial statement changes on external communications. In particular: – Confirm 2011 investor communications are IFRS compliant regarding guidance and expected earnings. – Monitor and update MD&A communications package. – Confirm investor relations process can respond to IFRS-related queries.	Analyze and publish the effect of IFRS on the financial statements throughout the project.	IFRS disclosure in the MD&A will be updated throughout the project. Vice President, Investor Relations is part of the IFRS Conversion Steering Committee.

Non-GAAP Financial Measures

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

Suncor provides a detailed numerical reconciliation of ROCE on an annual basis in the company's annual MD&A, which is to be read in conjunction with the company's annual consolidated financial statements. For a summarized narrative reconciliation of ROCE calculated on a March 31, 2009 interim basis, please refer to page 36.

Cash flow from operations is expressed before changes in non-cash working capital. A reconciliation of net earnings to cash flow from operations is provided in the Schedules of Segmented Data, which are an integral part of Suncor's March 31, 2009 unaudited interim consolidated financial statements.

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

For the three months ended March 31	**2009**	2008
Cash flow from operations ($ millions)	**479**	1 161
Weighted number of shares outstanding – basic (millions of shares)	**936.3**	926.2
Cash flow from operations – basic ($ per share)	**0.51**	1.25

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.

Oil Sands Operating Costs – Total Operations

	Three months ended March 31			
	2009		2008	
(unaudited)	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses	**909**		717	
Natural gas costs, inventory changes, stock-based compensation, and other	**3**		(155)	
Safe mode costs	**(175)**		—	
Non-monetary transactions	**(26)**		(26)	
Accretion of asset retirement obligations	**27**		14	
Taxes other than income taxes	**29**		16	
Cash costs	**767**	**30.65**	566	25.10
Natural gas	**75**	**3.00**	111	5.00
Purchased bitumen (excluding other reported product purchases)	**1**	**0.05**	33	1.45
Cash operating costs	**843**	**33.70**	710	31.55
Project start-up costs	**16**	**0.65**	7	0.30
Total cash operating costs	**859**	**34.35**	717	31.85
Depreciation, depletion and amortization	**183**	**7.30**	129	5.75
Total operating costs	**1 042**	**41.65**	846	37.60
Production (thousands of barrels per day)	**278.0**		248.0	

Oil Sands Operating Costs – In-Situ Bitumen Production Only

	Three months ended March 31			
	2009		2008	
(unaudited)	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses	**65**		89	
Natural gas costs	**(30)**		(45)	
Taxes other than income taxes	**5**		2	
Cash costs	**40**	**10.50**	46	14.60
Natural gas	**30**	**7.90**	45	14.10
Cash operating costs	**70**	**18.40**	91	28.70
In-situ (Firebag) start-up costs	**13**	**3.35**	1	0.35
Total cash operating costs	**83**	**21.75**	92	29.05
Depreciation, depletion and amortization	**27**	**7.10**	21	6.75
Total operating costs	**110**	**28.85**	113	35.80
Production (thousands of barrels per day)	**42.4**		34.6	

Notice – Forward-Looking Information

This Management's Discussion and Analysis contains certain forward-looking statements and other information 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 and other information 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," "outlook," "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

Suncor's outlook includes a production range of +5%/−10% based on our current expectations, estimates, projections and assumptions. Uncertainties in the estimating process and the impact of future events may cause actual results to differ, in some cases materially, from our estimates. Assumptions are based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be relevant. For a description of assumptions and risk factors specifically related to the 2009 outlook, see page 3 of our first quarter 2009 report to Shareholders.

The risks, uncertainties and other factors that could influence actual results include but are not limited to, market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates; availability of third-party bitumen; success of hedging strategies, maintaining a desirable debt to cash flow ratio; changes in the general economic, market and business conditions; fluctuations in supply and demand for Suncor's products; commodity prices, interest rates 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 and regulatory projects (for example, the emissions reduction modifications at our Firebag in-situ development); 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; the cost of compliance with current and 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; labour and material shortages; uncertainties resulting from potential delays or changes in plans with respect to projects or capital expenditures; actions by governmental authorities including the imposition of taxes or changes to fees and royalties, changes in environmental and other regulations (for example, the Government of Alberta's review of the unintended consequences of the proposed Crown royalty regime, the Government of Canada's current review of greenhouse gas emission regulations); the ability and willingness of parties with whom we have material relationships to perform their obligations to us; and the occurrence of unexpected events such as 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.

The forward-looking statements and information relating to the proposed transaction between Suncor and Petro-Canada are based on certain key expectations and assumptions made by us, including expectations and assumptions concerning: the accuracy of reserve and resource estimates; customer demand for the merged company's products; commodity prices and interest and foreign exchange rates; planned synergies, capital efficiencies and cost-savings; applicable royalty rates and tax laws; future production rates; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour and services; and the receipt, in a timely manner, of regulatory, security holder and third party approvals in respect of the proposed merger. In addition, forward-looking statements and information concerning the anticipated completion of the proposed transaction and the anticipated timing for completion of the transaction are provided in reliance on certain assumptions that we believe are reasonable at this time, including assumptions as to the time required to prepare and mail the shareholder meeting materials; the timing of receipt of the necessary regulatory, court and other third party approvals; and the time necessary to satisfy the conditions to the closing of the transaction. These dates may change for a number of reasons, including unforeseen delays in preparing meeting materials, inability to secure necessary regulatory, court or other third party approvals in the time assumed or the need for additional time to satisfy the conditions to the completion of the transaction. As a result of the foregoing, readers should not place undue reliance on the forward-looking statements and information concerning these times. Although we believe that the expectations and assumptions on which such forward-looking statements and information are based are reasonable, undue reliance should not be placed on the forward-looking statements and information because we can give no assurance that they will prove to be correct.

Since forward-looking statements and information relating to the proposed transaction address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. There are risks also inherent in the nature of the proposed transaction, including: failure to realize anticipated synergies or cost savings; risks regarding the integration of the two entities; incorrect assessments of the values of the other entity; and failure to obtain any required regulatory and other third party approvals (or to do so in a timely manner). 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 and Comprehensive Income

(unaudited)

($ millions)	Three months ended March 31 2009	2008
Revenues (note 3)	**4 814**	5 988
Expenses		
Purchases of crude oil and products	**848**	1 258
Operating, selling and general (note 7)	**1 155**	973
Energy trading activities (note 3)	**2 197**	1 852
Transportation and other costs	**68**	51
Depreciation, depletion and amortization	**302**	248
Accretion of asset retirement obligations	**29**	16
Exploration	**7**	12
Royalties (note 10)	**31**	322
Taxes other than income taxes	**187**	150
Loss on disposal of assets	**17**	2
Project start-up costs	**16**	7
Financing expenses (note 5)	**199**	79
	5 056	4 970
Earnings (Loss) Before Income Taxes	**(242)**	1 018
Provision for (Recovery of) Income Taxes		
Current	**90**	156
Future	**(143)**	154
	(53)	310
Net Earnings (Loss)	**(189)**	708
Other comprehensive income (note 12)	**34**	47
Comprehensive Income (Loss)	**(155)**	755
Net Earnings (Loss) Per Common Share (dollars), (note 6)		
Basic	**(0.20)**	0.77
Diluted	**(0.20)**	0.75
Cash dividends	**0.05**	0.05

See accompanying notes

Consolidated Balance Sheets

(unaudited)

($ millions)	March 31 2009	December 31 2008 (restated) (note 2)
Assets		
Current assets		
Cash and cash equivalents	**431**	660
Accounts receivable (note 3)	**1 563**	1 580
Inventories	**1 136**	909
Income taxes receivable	**168**	67
Future income taxes	**54**	21
Total current assets	**3 352**	3 237
Property, plant and equipment, net (note 2)	**29 697**	28 882
Other assets (notes 2 and 3)	**396**	409
Total assets	**33 445**	32 528
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**11**	11
Accounts payable and accrued liabilities (note 3)	**2 998**	3 229
Taxes other than income taxes	**88**	97
Income taxes payable	**14**	81
Future income taxes	**64**	111
Total current liabilities	**3 175**	3 529
Long-term debt (note 11)	**9 058**	7 875
Accrued liabilities and other (notes 3 and 8)	**2 290**	1 986
Future income taxes	**4 556**	4 615
Shareholders' equity (see below)	**14 366**	14 523
Total liabilities and shareholders' equity	**33 445**	32 528

Shareholders' Equity

	Number (thousands)		Number (thousands)	
Share capital	**936 687**	**1 131**	935 524	1 113
Contributed surplus		**315**		288
Accumulated other comprehensive income (note 12)		**131**		97
Retained earnings		**12 789**		13 025
Total shareholders' equity		**14 366**		14 523

See accompanying notes

Consolidated Statements of Cash Flows

(unaudited)

($ millions)	Three months ended March 31 2009	2008
Operating Activities		
Cash flow from operations	**479**	1 161
Decrease (increase) in operating working capital		
Accounts receivable	**19**	(431)
Inventories	**(227)**	(142)
Accounts payable and accrued liabilities	**183**	387
Taxes payable/receivable	**(177)**	(121)
Cash flow from operating activities	**277**	854
Cash Used in Investing Activities	**(1 516)**	(1 410)
Net Cash Deficiency Before Financing Activities	**(1 239)**	(556)
Financing Activities		
Increase in short-term debt	**1**	—
Net increase in long-term debt	**1 037**	651
Issuance of common shares under stock option plan	**15**	24
Dividends paid on common shares	**(47)**	(43)
Cash flow provided by financing activities	**1 006**	632
Increase (Decrease) in Cash and Cash Equivalents	**(233)**	76
Effect of Foreign Exchange on Cash and Cash Equivalents	**4**	12
Cash and Cash Equivalents at Beginning of Period	**660**	569
Cash and Cash Equivalents at End of Period	**431**	657

See accompanying notes

Consolidated Statements of Changes in Shareholders' Equity

(unaudited)

($ millions)	Share Capital	Contributed Surplus	Accumulated Other Comprehensive Income (AOCI)	Retained Earnings
At December 31, 2007	881	194	(253)	11 074
Net earnings	—	—	—	708
Dividends paid on common shares	—	—	—	(43)
Issued for cash under stock option plan	29	(5)	—	—
Issued under dividend reinvestment plan	3	—	—	(3)
Stock-based compensation expense	—	44	—	—
Change in AOCI related to foreign currency translation	—	—	53	—
Change in AOCI related to derivative hedging activities	—	—	(6)	—
At March 31, 2008	913	233	(206)	11 736
At December 31, 2008	1 113	288	97	13 025
Net earnings (loss)	**—**	**—**	**—**	**(189)**
Dividends paid on common shares	**—**	**—**	**—**	**(47)**
Issued for cash under stock option plan	**18**	**(3)**	**—**	**—**
Stock-based compensation expense	**—**	**27**	**—**	**—**
Income tax benefit of stock option deduction in the U.S.	**—**	**3**	**—**	**—**
Change in AOCI related to foreign currency translation	**—**	**—**	**32**	**—**
Change in AOCI related to derivative hedging activities	**—**	**—**	**2**	**—**
At March 31, 2009	**1 131**	**315**	**131**	**12 789**

See accompanying notes

Schedules of Segmented Data

(unaudited)

Three months ended March 31

($ millions)	Oil Sands 2009	Oil Sands 2008	Natural Gas 2009	Natural Gas 2008	Refining and Marketing 2009	Refining and Marketing 2008	Corporate and Eliminations 2009	Corporate and Eliminations 2008	Total 2009	Total 2008
EARNINGS										
Revenues										
Operating revenues	**945**	1 945	**99**	162	**1 519**	2 022	**5**	5	**2 568**	4 134
Energy trading activities	**—**	—	**—**	—	**2 247**	1 881	**(1)**	(33)	**2 246**	1 848
Intersegment revenues	**171**	301	**15**	10	**—**	—	**(186)**	(311)	**—**	—
Interest	**—**	—	**—**	—	**—**	—	**—**	6	**—**	6
	1 116	2 246	**114**	172	**3 766**	3 903	**(182)**	(333)	**4 814**	5 988
Expenses										
Purchases of crude oil and products	**62**	47	**—**	—	**958**	1 553	**(172)**	(342)	**848**	1 258
Operating, selling and general	**909**	717	**42**	40	**175**	175	**29**	41	**1 155**	973
Energy trading activities	**—**	—	**—**	—	**2 198**	1 853	**(1)**	(1)	**2 197**	1 852
Transportation and other costs	**57**	42	**5**	3	**6**	6	**—**	—	**68**	51
Depreciation, depletion and amortization	**183**	129	**56**	58	**56**	51	**7**	10	**302**	248
Accretion of asset retirement obligations	**27**	14	**2**	2	**—**	—	**—**	—	**29**	16
Exploration	**6**	9	**1**	3	**—**	—	**—**	—	**7**	12
Royalties (note 10)	**8**	282	**23**	40	**—**	—	**—**	—	**31**	322
Taxes other than income taxes	**37**	27	**—**	—	**150**	123	**—**	—	**187**	150
Loss on disposal of assets	**17**	—	**—**	—	**—**	2	**—**	—	**17**	2
Project start-up costs	**16**	7	**—**	—	**—**	—	**—**	—	**16**	7
Financing expenses	**—**	—	**—**	—	**—**	—	**199**	79	**199**	79
	1 322	1 274	**129**	146	**3 543**	3 763	**62**	(213)	**5 056**	4 970
Earnings (loss) before income taxes	**(206)**	972	**(15)**	26	**223**	140	**(244)**	(120)	**(242)**	1 018
Income taxes	**96**	(277)	**5**	(7)	**(73)**	(45)	**25**	19	**53**	(310)
Net earnings (loss)	**(110)**	695	**(10)**	19	**150**	95	**(219)**	(101)	**(189)**	708
As at March 31										
TOTAL ASSETS	**27 235**	20 052	**1 908**	1 874	**4 567**	5 457	**(265)**	(948)	**33 445**	26 435

Schedules of Segmented Data (continued)

(unaudited)

	Three months ended March 31									
	Oil Sands		Natural Gas		Refining and Marketing		Corporate and Eliminations		Total	
($ millions)	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008
CASH FLOW BEFORE FINANCING ACTIVITIES										
Cash flow from (used in) operating activities:										
Cash flow from (used in) operations										
Net earnings (loss)	**(110)**	695	**(10)**	19	**150**	95	**(219)**	(101)	**(189)**	708
Non-cash items included in earnings										
Depreciation, depletion and amortization	**183**	129	**56**	58	**56**	51	**7**	10	**302**	248
Future income taxes	**(222)**	135	**6**	3	**41**	31	**32**	(15)	**(143)**	154
Loss on disposal of assets	**17**	—	**—**	—	**—**	2	**—**	—	**17**	2
Stock-based compensation expense	**14**	22	**1**	2	**4**	7	**8**	13	**27**	44
Other	**(11)**	(24)	**2**	—	**4**	5	**161**	72	**156**	53
Increase (decrease) in deferred credits and other	**308**	(47)	**—**	—	**—**	(1)	**1**	—	**309**	(48)
Total cash flow from (used in) operations	**179**	910	**55**	82	**255**	190	**(10)**	(21)	**479**	1 161
Decrease (increase) in operating working capital	**(1 056)**	(93)	**1**	41	**66**	(110)	**787**	(145)	**(202)**	(307)
Total cash flow from (used in) operating activities	**(877)**	817	**56**	123	**321**	80	**777**	(166)	**277**	854
Cash from (used in) investing activities:										
Capital and exploration expenditures	**(957)**	(1 310)	**(109)**	(126)	**(32)**	(49)	**—**	(4)	**(1 098)**	(1 489)
Deferred outlays and other investments	**(25)**	(6)	**—**	—	**—**	(1)	**—**	(4)	**(25)**	(11)
Decrease (increase) in investing working capital	**(395)**	102	**—**	—	**—**	(12)	**2**	—	**(393)**	90
Total cash from (used in) investing activities	**(1 377)**	(1 214)	**(109)**	(126)	**(32)**	(62)	**2**	(8)	**(1 516)**	(1 410)
Net cash surplus (deficiency) before financing activities	**(2 254)**	(397)	**(53)**	(3)	**289**	18	**779**	(174)	**(1 239)**	(556)

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 change as described in note 2, Change in Accounting Policies. Certain information and disclosures normally required to be included in notes to the annual consolidated financial statements have been condensed or omitted.

In the opinion of management, these interim consolidated financial statements contain all adjustments of a normal and recurring nature necessary to present fairly Suncor Energy Inc.'s (Suncor) financial position at March 31, 2009 and the results of its operations and cash flows for the three month periods ended March 31, 2009 and 2008.

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

2. CHANGE IN ACCOUNTING POLICIES

Goodwill and Intangible Assets

On January 1, 2009, the company retroactively adopted Canadian Institute of Chartered Accountants (CICA) Handbook section 3064 "Goodwill and Intangible Assets". This new standard replaces section 3062 "Goodwill and Other Intangible Assets" and section 3450 "Research and Development Costs", and focuses on the criteria for asset recognition in the financial statements, including those internally developed. The impact of adopting this standard resulted in a change in the classification of our deferred maintenance shutdown costs that had previously been classified within other assets and amortized over the period to the next shutdown, as follows:

Change in Consolidated Balance Sheets

($ millions, increase/(decrease))	**As at March 31 2009**	As at December 31 2008
Property, plant and equipment, net	**522**	566
Other assets	**(522)**	(566)

3. FINANCIAL INSTRUMENTS AND FINANCIAL RISK FACTORS

Derivatives are financial instruments that either imitate or counter the price movements of stocks, bonds, currencies, commodities and interest rates. Suncor uses derivatives to reduce (hedge) its exposure to fluctuations in commodity prices and foreign currency exchange rates and to manage interest rate or currency-sensitive assets and liabilities. Suncor also uses derivatives for trading purposes. When used in a trading activity, the company is attempting to realize a gain on the fluctuations in the market value of the derivative.

Forwards and futures are contracts to purchase or sell a specific item at a specified date and price. When used as hedges, forwards and futures help to manage the exposure to losses that could result if commodity prices or foreign currency exchange rates change adversely.

An option is a contract where its holder, for a fee, has purchased the right (but not the obligation) to buy or sell a specified item at a fixed price during a specified period. Options used as hedges help to protect against adverse changes in commodity prices, interest rates, or foreign currency exchange rates.

A costless collar is a combination of two option contracts that limit the holder's exposure to changes in prices to within a specific range. The "costless" nature of this derivative is achieved by buying a put option (the right to sell) for consideration equal to the premium received from selling a call option (the right to purchase).

A swap is a contract where two parties exchange commodity, currency, interest or other payments in order to alter the nature of the payments. For example, fixed interest rate payments on debt may be converted to payments based on a floating interest rate, or vice versa; a domestic currency debt may be converted to a foreign currency debt.

Hedge accounting is a method for recognizing the gains, losses, revenues and expenses associated with the items in a hedging relationship at the time when the underlying transaction impacts earnings. Suncor has elected to use hedge accounting on certain derivatives linked to future commodity and financial transactions.

See below for more technical details and amounts.

(a) Balance Sheet Financial Instruments

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

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

The company's fixed-term debt is accounted for under the amortized cost method. Upon initial recognition, the cost of the debt is its fair value, adjusted for any associated transaction costs. We do not recognize gains or losses arising from changes in the fair value of this debt until the gains or losses are realized. Gains or losses on our U.S. dollar denominated long-term debt resulting from changes in the exchange rate are recognized in the period in which they occur. At March 31, 2009, the carrying value of our fixed-term debt accounted for under the amortized cost method was $6.8 billion (December 31, 2008 – $6.7 billion) and the fair value was $5.4 billion (December 31, 2008 – $5.4 billion).

(b) Hedges – documented as part of a qualifying hedge relationship

Fair Value Hedges

At March 31, 2009, the company had interest rate swaps classified as fair value hedges outstanding until August 2011, relating to fixed-rate debt. There was no ineffectiveness recognized on interest rate swaps designated as fair value hedges during the three month periods ended March 31, 2009 and March 31, 2008.

The earnings impact associated with hedge ineffectiveness on derivative contracts to hedge risks specific to individual transactions during the three month period ended March 31, 2009 was a loss of $1 million net of income taxes of less than $1 million (2008 – loss of $1 million, net of income taxes of $1 million).

Cash Flow Hedges

At March 31, 2009, the company had hedged a portion of its forecasted cash flows subject to natural gas price risk. There was no earnings impact associated with realized and unrealized hedge ineffectiveness on derivative contracts designated as cash flow hedges during the three month periods ended March 31, 2009 and March 31, 2008.

Fair Value of Hedging Derivative Financial Instruments

The fair value of hedging derivative financial instruments as recorded, is the estimated amount that the company would receive (pay) to terminate the hedging derivative contracts. Such amounts, which also represent the unrealized gain (loss) on the contracts, were as follows:

($ millions)	**March 31 2009**	December 31 2008
Revenue hedge swaps and collars	**1**	(2)
Fixed to floating interest rate swaps	**20**	24
Specific hedges of individual transactions	**(8)**	(11)
Fair value of outstanding hedging derivative financial instruments	**13**	11

Accumulated Other Comprehensive Income (AOCI)

A reconciliation of changes in accumulated other comprehensive income (AOCI) attributable to derivative hedging activities for the three month periods ending March 31 is as follows:

($ millions)	**2009**	2008
AOCI attributable to derivative hedging activities, beginning of the period, net of income taxes of $5 (2008 – $4)	**13**	13
Current period net changes arising from cash flow hedges, net of income taxes of $nil (2008 – $2)	**—**	(7)
Net unrealized hedging losses at the beginning of the year reclassified to earnings during the period, net of income taxes of $nil (2008 – $nil)	**2**	1
AOCI attributable to derivative hedging activities, at March 31, net of income taxes of $5 (2008 – $2)	**15**	7

(c) Hedges – Not Documented as Part of a Qualifying Hedge Relationship

The company also periodically enters into derivative financial instruments such as options, basis swaps, and heat rate swaps that either do not qualify for hedge accounting treatment or hedges that the company has not elected to document as part of a qualifying hedge relationship. The earnings impact associated with these contracts for the three month period ended March 31, 2009, was a loss of $148 million, net of income taxes of $59 million (2008 – a loss of $10 million, net of income taxes of $4 million).

Significant contracts outstanding at March 31 were as follows:

Crude oil	Quantity (bpd)	Average Price [1] (US$/bbl)	Revenue Hedged [2] (Cdn$ millions)	Hedge Period [3]
Purchased puts [4]	55 000	60.00	1 144	2009
Fixed price	126 575	50.68	2 223	2009
Purchased puts [4]	55 000	60.00	1 518	2010
Sold puts [5]	54 753	60.00	(1 511)	2010
Collars – floor	50 041	50.00	1 151	2010
Collars – cap	49 986	68.06	1 565	2010

(1) Average price for crude puts is US$ WTI per barrel at Cushing, Oklahoma.
(2) The revenue hedged is translated to Cdn$ at the March 31, 2009 exchange rate for convenience purposes.
(3) Original hedge term is for the full year.
(4) Total premium paid was US$59 million.
(5) Premium received was US$213 million.

(d) Energy Trading Activities

In addition to the financial derivatives used for hedging activities, the company uses physical and financial energy contracts, including swaps, forwards and options to earn trading revenues. Physical energy trading contracts involve activities intended to enhance prices and satisfy physical deliveries to customers. Net pretax earnings for the three month periods ended March 31, as recorded in our refining and marketing segment, were as follows:

Net Pretax Earnings (Loss)

($ millions)	**2009**	2008
Physical energy contracts trading activity	**51**	30
Financial energy contracts trading activity	**1**	—
General and administrative costs	**(3)**	(2)
Total	**49**	28

(e) Fair Value of Non-Designated Derivative Financial Instruments

The fair value of unsettled (unrealized) non-designated derivative financial instruments, which includes all contracts referenced in section (c) & (d) above are as follows:

($ millions)	**March 31 2009**	December 31 2008
Derivative financial instrument assets (1)	**462**	635
Derivative financial instrument liabilities (2)	**497**	14
Net assets (liabilities)	**(35)**	621

(1) As at March 31, 2009, $217 million is recorded in accounts receivable (December 31, 2008 – $376 million) and $245 million is recorded in other assets (December 31, 2008 – $259 million) in the Consolidated Balance Sheets.

(2) As at March 31, 2009, $172 million is recorded in accounts payable and accrued liabilities (December 31, 2008 – $14 million) and $325 million is recorded in accrued liabilities and other in the Consolidated Balance Sheets.

Change in fair value of net assets

($ millions)	**2009**
Fair value of contracts at December 31, 2008	621
Fair value of contracts realized during the period	**(208)**
Fair value of contracts entered into during the period	**(381)**
Changes in values attributable to market price and other market changes during the period	**(67)**
Fair value of contracts outstanding at March 31, 2009	**(35)**

Financial Risk Factors

The company is exposed to a number of different financial risks arising from normal course business exposures, as well as the company's use of financial instruments. These risk factors include market risks relating to commodity prices, foreign currency risk and interest rate risk, as well as liquidity risk and credit risk.

The company maintains a formal governance process to manage its financial risks. The company's Risk Management Committee (RMC) is charged with the oversight of the company's risk management for trading risk management activities which are defined as strategic hedging, optimization trading, marketing and speculative trading. The RMC, acting under board authority, meets regularly to monitor limits on risk exposures, review policy compliance and validate risk-related methodologies and procedures. All risk management activity is carried out by specialist teams that have the appropriate skills, experience and supervision with the appropriate financial and management controls.

At March 31, 2009, the company's exposure to risks associated arising from the use of financial instruments had not changed significantly from December 31, 2008, except for our sensitivity related to commodity price risk.

Changes in commodity prices on our financial contracts would have the following impact on our net earnings and other comprehensive income for the three months ended March 31, 2009:

Sensitivity Analysis

($ millions)	March 31, 2009[1]	Change	Net Earnings	Other Comprehensive Income
Crude Oil	US$63.16/barrel			
Price increase		US$1.00/barrel	(75)	—
Price decrease		US$1.00/barrel	75	—
Natural Gas	US$5.11/mcf			
Price increase		US$0.10/mcf	(2)	—
Price decrease		US$0.10/mcf	2	—

(1) Prices represent the average of the forward strip prices at March 31, 2009.

For full discussion of the company's financial risk factors, see page 67 of our 2008 Annual Report.

4. CAPITAL STRUCTURE FINANCIAL POLICIES

The company's primary capital management objective is to maintain a solid investment-grade credit rating profile. This objective affords the company the financial flexibility and access to the capital it requires to execute on its growth objectives.

The company monitors capital through two key ratios: net debt to cash flow from operations and total debt to total debt plus shareholders' equity.

Net debt to cash flow from operations is calculated as short-term debt plus long-term debt less cash and cash equivalents divided by the twelve month trailing cash flow from operations.

Total debt to total debt plus shareholders' equity is calculated as short term-debt plus long-term debt divided by short-term debt plus long-term debt plus shareholders' equity.

The company's strategy during the first quarter of 2009, which was unchanged from 2008, was to maintain the measure set out in the following schedule. The company believes that maintaining our capital target helps to provide the company access to capital at a reasonable cost by maintaining solid investment-grade credit ratings. The company operates in a cyclical business environment and ratios may periodically fall outside of management targets.

At March 31, ($ millions)	Capital Measure Target	**2009**	2008
Components of ratios			
Short-term debt		**11**	7
Long-term debt		**9 058**	4 552
Total debt		**9 069**	4 559
Cash and equivalents		**431**	657
Net debt		**8 638**	3 902
Shareholders' equity		**14 366**	12 676
Total capitalization (total debt + shareholders' equity)		**23 435**	17 235
Cash flow from operations (trailing twelve months)		**3 781**	4 345
Net debt/cash flow from operations	< 2.0 times	**2.3**	0.9
Total debt/total debt plus shareholders' equity		**39%**	26%

5. FINANCING EXPENSES (INCOME)

($ millions)	Three months ended March 31 **2009**	2008
Interest expense on debt	**118**	64
Capitalized interest	**(54)**	(64)
Net interest expense	**64**	—
Foreign exchange loss on long-term debt	**148**	86
Other foreign exchange (gain) loss	**(13)**	(7)
Total financing expenses	**199**	79

6. RECONCILIATION OF BASIC AND DILUTED EARNINGS PER COMMON SHARE

($ millions)	Three months ended March 31 **2009**	2008 (restated)
Net earnings (loss)	**(189)**	708
(millions of common shares)		
Weighted-average number of common shares	**936**	926
Dilutive securities:		
Options issued under stock-based compensation plans	**8**	20
Weighted-average number of diluted common shares	**944**	946
(dollars per common share)		
Basic earnings (loss) per share [(a)]	**(0.20)**	0.77
Diluted earnings (loss) per share [(b)]	**(0.20)**	0.75

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

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

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

7. STOCK-BASED COMPENSATION

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

After the date of grant, employees and non-employee directors that hold options must earn the right to exercise them. This is done by the holder 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 the company's shareholder return relative to a peer group of companies.

A restricted share unit is a time-vested award with a three-year term entitling employees to receive cash.

(a) Stock Option Plans:

(i) SunShare 2012 Performance Stock Option Plan

The company granted 493,000 options in the first quarter of 2009 (230,000 options granted during the first quarter of 2008) to all eligible permanent full-time and part-time employees, both executive and non-executive, under its SunShare 2012 performance stock option plan. During 2008, in connection with the achievement of a predetermined performance criterion, 25% of the outstanding options vested under the SunShare 2012 plan and will become exercisable on January 1, 2010. The remaining 75% of outstanding options may vest on January 1, 2013 if further specified performance targets are met. All unvested options at January 1, 2013, which have not previously expired or been cancelled, will automatically expire.

(ii) Executive Stock Plan

Under this plan, the company granted 711,000 common share options in the first quarter of 2009 (802,000 options granted during the first quarter of 2008) to non-employee directors and certain executives and other senior members of the company. Options granted have a ten-year life and vest annually over a three-year period.

(iii) Key Contributor Stock Option Plan

Under this plan, the company granted 565,000 common share options in the first quarter of 2009 (2,340,000 options granted during the first quarter of 2008) to non-insider senior managers and key employees. Options granted have a ten-year life and vest annually over a three-year period.

Fair Value of Options Granted

The fair values of all common share options granted during the period are estimated as at the grant date using the Monte Carlo simulation approach for the SunShare 2012 option plan and the Black-Scholes option-pricing model for all other option plans. The weighted-average fair values of the options granted during the various periods and the weighted-average assumptions used in their determination are as noted below:

	Three months ended March 31	
	2009	2008
Quarterly dividend per share	**$0.05**	$0.05
Risk-free interest rate	**2.17%**	3.62%
Expected life	**6 years**	6 years
Expected volatility	**39%**	28%
Weighted-average fair value per option	**$9.19**	$15.65

Stock-based compensation expense recognized in the first quarter of 2009 related to stock options plans was $27 million (2008 – $44 million).

(b) Performance Share Units (PSUs)

In the first quarter of 2009 the company issued 1,141,000 PSUs (762,000 PSUs granted during the first quarter of 2008). Expense recognized in the first quarter of 2009 was $8 million (2008 – recovery of $5 million of previously recognized expense).

(c) Restricted Share Units (RSUs)

(i) SunShare 2012 Restricted Share Units

In the first quarter of 2009 the company issued 29,000 RSUs (930,000 RSUs granted during the first quarter of 2008) under its SunShare 2012 restricted share unit plan. Expense recognized in the first quarter of 2009 was $4 million (2008 – $4 million).

(ii) Restricted Share Unit Plan

The company issued 1,562,000 RSUs in the first quarter of 2009 to non-insider senior managers and key employees under its new restricted share unit plan. Expense recognized in the first quarter of 2009 was $9 million.

8. EMPLOYEE FUTURE BENEFITS LIABILITY

The company's pension plans and other post-retirement benefits programs are described in note 10 of the company's 2008 Annual Report. The following is the status of the net periodic benefit cost for the three months ended March 31.

	Pension Benefits		Other Post-retirement Benefits	
	2009	2008	**2009**	2008
Current service costs	**13**	14	**1**	1
Interest costs	**13**	12	**2**	2
Expected return on plan assets	**(10)**	(11)	**—**	—
Amortization of net actuarial loss	**5**	6	**—**	1
Net periodic benefit cost recognized	**21**	21	**3**	4

9. SUPPLEMENTAL INFORMATION

	Three months ended March 31	
($ millions)	**2009**	2008
Interest paid	**61**	66
Income taxes paid	**240**	273

10. ROYALTIES

For a description of the Alberta Crown royalty regimes in effect for our oil sands operations, see page 15 of our 2008 Annual Report.

Our current estimation of Alberta Crown royalties is based on regulations and crown agreements currently in effect. Alberta Crown royalties in effect for each of our oil sands projects 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 at 25% to 40% (the R-C Royalty), subject to a minimum payment of 1% to 9% of R (the Minimum Royalty).

Changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each oil sands project; changes resulting from regulatory audits of prior year filings; changes in legislation and the occurrence of unexpected events all have the potential to have an impact on oil sands royalties payable to the Crown.

The oil sands royalty expense was $8 million for the first three months of 2009, compared to $282 million for the first three months of 2008. The lower expense was due to a significant decrease in price realizations in this quarter, causing royalty eligible operating costs and capital expenditures to exceed revenues related to bitumen, less related transportation costs. As a result, royalties were paid on 1% of R instead of 25% of R minus C. In addition, effective January 1, 2009, revenues from our base mine operations are now based on bitumen values (previously based on synthetic crude oil) with a corresponding exclusion of upgrading costs from royalty eligibility.

The balance of the consolidated royalty expense is in respect of natural gas royalties of $23 million (2008 – $40 million).

11. LONG-TERM DEBT AND CREDIT FACILITIES

($ millions)	**March 31 2009**	December 31 2008
Fixed-term debt, redeemable at the option of the Company		
6.85% Notes, denominated in U.S. dollars, due in 2039 (US$750)	**945**	918
6.50% Notes, denominated in U.S. dollars, due in 2038 (US$1150)	**1 450**	1 408
5.95% Notes, denominated in U.S. dollars, due in 2034 (US$500)	**630**	612
7.15% Notes, denominated in U.S. dollars, due in 2032 (US$500)	**630**	612
6.10% Notes, denominated in U.S. dollars, due in 2018 (US$1250)	**1 575**	1 531
5.39% Series 4 Medium Term Notes, due in 2037	**600**	600
5.80% Series 4 Medium Term Notes, due in 2018	**700**	700
6.70% Series 2 Medium Term Notes, due in 2011	**500**	500
	7 030	6 881
Revolving-term debt, with interest at variable rates		
Commercial paper and bankers' acceptances	**1 971**	934
Total unsecured long-term debt	**9 001**	7 815
Secured long-term debt	**13**	13
Capital leases	**103**	103
Fair value of interest swaps	**12**	16
Deferred financing costs	**(71)**	(72)
Total long-term debt	**9 058**	7 875

At March 31, 2009, undrawn lines of credit were approximately $1,943 million, as follows:

($ millions)	**2009**
Facility that is fully revolving for 364 days, has a term period of one year and expires in 2009	**480**
Facility that is fully revolving for a period of five years and expires in 2013	**3 750**
Facilities that can be terminated at any time at the option of the lenders	**53**
Total available credit facilities	**4 283**
Credit facilities supporting outstanding commercial paper and bankers' acceptances	**1 971**
Credit facilities supporting standby letters of credit	**369**
Total undrawn credit facilities	**1 943**

12. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of accumulated other comprehensive income, net of income taxes, are as follows:

($ millions)	**March 31 2009**	December 31 2008
Unrealized foreign currency translation adjustments	**116**	84
Unrealized gains and losses on derivative hedging activities	**15**	13
Total	**131**	97

13. PETRO-CANADA MERGER

On March 23, 2009, Suncor and Petro-Canada (TSX:PCA) (NYSE:PCZ) announced that they have agreed to merge the two companies. Upon completion of the transaction, which will require shareholder approval, regulatory approval, as well as a review by the Canadian Competition Bureau, the combined entity is expected to operate corporately and trade under the Suncor name.

Highlights

(unaudited)

	2009	2008
Cash Flow from Operations		
(dollars per common share – basic)		
For the three months ended March 31		
Cash flow from operations (1)	**0.51**	1.25
Ratios		
For the twelve months ended March 31		
Return on capital employed (%) (2)	**16.0**	28.8
Return on capital employed (%) (3)	**11.3**	21.1
Net debt to cash flow from operations (times) (4)	**2.3**	0.9
Interest coverage on long-term debt (times)		
Net earnings (5)	**4.8**	17.0
Cash flow from operations (6)	**10.4**	22.0
As at March 31		
Debt to debt plus shareholders' equity (%) (7)	**38.7**	26.5
Common Share Information (8)		
As at March 31		
Share price at end of trading		
Toronto Stock Exchange – Cdn$	**28.14**	49.61
New York Stock Exchange – US$	**22.21**	48.18
Common share options outstanding (thousands)	**46 620**	55 774
For the three months ended March 31		
Average number outstanding, weighted monthly (thousands)	**936 293**	926 216

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) For the twelve month period ended; net earnings (2009 – $2,227 million; 2008 – $3,010 million) after adjustment to add back after-tax financing expense (2009 – $987 million; 2008 – income of $105 million) divided by average capital employed (2009 – $13,941 million; 2008 – $10,436 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 41 of Suncor's 2008 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: 2009 – $19,757 million; 2008 – $14,256 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.

(8) In May 2008, Suncor's common shares were split on a two-for-one basis. Prior periods have been restated to reflect the split.

Quarterly Operating Summary

(unaudited)

	Mar 31 2009	Dec 31 2008	Sept 30 2008	June 30 2008	Mar 31 2008	Twelve months ended Dec 31 2008
		Three months ended				
OIL SANDS						
Production [1], [a]						
Total production	**278.0**	243.8	245.6	174.6	248.0	228.0
Firebag	**42.4**	39.7	40.4	34.7	34.6	37.4
Sales [a]						
Light sweet crude oil	**108.8**	95.7	48.1	68.2	96.2	77.0
Diesel	**22.8**	19.1	10.9	21.2	28.0	19.8
Light sour crude oil	**102.7**	144.2	157.4	91.8	120.8	128.7
Bitumen	**9.1**	3.1	2.6	0.3	0.1	1.5
Total sales	**243.4**	262.1	219.0	181.5	245.1	227.0
Average sales price [2], [b]						
Light sweet crude oil	**69.26**	64.58	121.96	122.12	100.93	97.54
Other (diesel, light sour crude oil and bitumen)	**48.85**	59.77	114.74	120.52	93.09	95.15
Total	**57.97**	61.53	116.32	121.12	96.16	95.96
Total *	**52.78**	61.20	117.14	122.39	96.22	96.33
Cash operating costs and Total operating costs – Total operations [c]						
Cash costs	**30.65**	35.35	27.80	40.10	25.10	31.45
Natural gas	**3.00**	4.05	4.30	8.75	5.00	5.25
Imported bitumen	**0.05**	1.90	1.90	2.00	1.45	1.80
Cash operating costs [3]	**33.70**	41.30	34.00	50.85	31.55	38.50
Project start-up costs	**0.65**	0.30	0.35	0.90	0.30	0.40
Total cash operating costs [4]	**34.35**	41.60	34.35	51.75	31.85	38.90
Depreciation, depletion and amortization	**7.30**	7.50	6.70	8.30	5.75	6.95
Total operating costs [5]	**41.65**	49.10	41.05	60.05	37.60	45.85
Cash operating costs and Total operating costs – In-situ bitumen production only [c]						
Cash costs	**10.50**	16.55	10.75	10.10	14.60	13.00
Natural gas	**7.90**	9.65	11.30	14.55	14.10	12.30
Cash operating costs [6]	**18.40**	26.20	22.05	24.65	28.70	25.30
Firebag start-up costs	**3.35**	—	0.80	1.65	0.35	0.65
Total cash operating costs [7]	**21.75**	26.20	22.85	26.30	29.05	25.95
Depreciation, depletion and amortization	**7.10**	6.55	5.40	6.70	6.75	6.35
Total operating costs [8]	**28.85**	32.75	28.25	33.00	35.80	32.30
Ending capital employed excluding major projects in progress [i]	**10 610**	9 352	9 035	7 716	7 130	
(for the twelve months ended)						
Return on capital employed [j]	**22.9**	35.5	46.0	43.6	43.2	
Return on capital employed [j]****	**13.9**	21.8	28.6	27.3	27.5	

Quarterly Operating Summary (continued)

(unaudited)

	Mar 31 2009	Three months ended Dec 31 2008	Sept 30 2008	June 30 2008	Mar 31 2008	Twelve months ended Dec 31 2008
NATURAL GAS						
Gross production **						
Natural gas [d]	**200**	195	197	205	209	202
Natural gas liquids and crude oil [a]	**3.1**	3.1	2.6	3.4	3.3	3.1
Total gross production [e]	**36.5**	35.6	35.4	37.7	38.2	36.7
Total gross production [f]	**219**	213	213	226	229	220
Average sales price [2]						
Natural gas [g]	**5.63**	6.90	9.10	9.62	7.30	8.23
Natural gas [g] *	**5.61**	6.84	9.14	9.68	7.31	8.25
Natural gas liquids and crude oil [b]	**39.03**	39.31	96.88	86.14	64.14	70.89
Net wells drilled						
Conventional – exploratory ***	**2**	2	4	2	2	10
– development	**5**	4	6	6	7	23
	7	6	10	8	9	33
Ending capital employed [i]	**1 195**	1 152	1 120	1 226	1 175	
(for the twelve months ended)						
Return on capital employed [j]	**5.0**	7.7	10.3	8.3	3.5	
REFINING AND MARKETING						
Refined product sales [h]						
Transportation fuels						
Gasoline – retail	**4.5**	4.6	4.5	4.5	4.6	4.6
– other	**11.9**	12.1	11.5	11.8	10.8	11.3
Distillate	**10.5**	10.9	10.6	11.5	10.4	10.8
Total transportation fuel sales	**26.9**	27.6	26.6	27.8	25.8	26.7
Petrochemicals	**1.0**	1.0	1.0	0.9	0.6	0.8
Asphalt	**2.0**	1.5	1.9	1.7	2.2	1.8
Other	**1.5**	1.4	2.5	2.7	1.9	2.2
Total refined product sales	**31.4**	31.5	32.0	33.1	30.5	31.5
Crude oil supply and refining						
Processed at refineries [h]	**25.5**	24.8	25.1	26.0	23.0	24.7
Utilization of refining capacity [j]	**90**	98	99	102	90	97
Ending capital employed excluding major projects in progress [i]	**2 985**	2 974	3 289	2 534	2 837	
(for the twelve months ended)						
Return on capital employed [j]	**3.7**	1.8	9.3	12.6	18.3	
Return on capital employed [j] ****	**3.7**	1.8	9.0	11.6	16.5	

Quarterly Operating Summary (continued)

Non GAAP Financial Measures

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

Definitions

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

Explanatory Notes

*	Excludes the impact of realized hedging activities.
**	Currently 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	(d) millions of cubic feet per day	(g) dollars per thousand cubic feet
(b) dollars per barrel	(e) thousands of barrels of oil equivalent per day	(h) thousands of cubic metres per day
(c) dollars per barrel rounded to the nearest $0.05	(f) millions of cubit feet equivalent per day	(i) $ millions
		(j) percentage

Metric conversion

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

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