FOURTH QUARTER 2009
Report to shareholders for the period ended December 31, 2009

Suncor Energy reports financial results for 2009 and operational goals for 2010

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 on page 9. 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.

On August 1, 2009, Suncor Energy Inc. completed its merger with Petro-Canada. The three and twelve month amounts ending December 31, 2009 reflect results of the post-merger Suncor from August 1, 2009 together with results of legacy Suncor only from January 1 through July 31, 2009. The comparative figures reflect solely the 2008 results of legacy Suncor. For further information with respect to the merger transaction, please refer to note 3 to the December 31, 2009 unaudited interim consolidated financial statements.

Suncor Energy Inc. recorded fourth quarter 2009 net earnings of $457 million ($0.29 per common share), compared to a net loss of $215 million ($0.24 per common share) for the fourth quarter of 2008. Operating earnings[1] in the fourth quarter of 2009 were $323 million ($0.21 per common share), compared to $14 million ($0.02 per common share) in the fourth quarter of 2008. Cash flow from operations[2] was $1.129 billion in the fourth quarter of 2009, compared to $231 million in the fourth quarter of 2008.

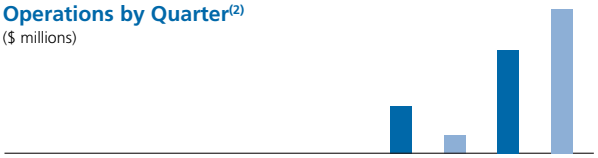
The increase in operating earnings and cash flow from operations in the fourth quarter of 2009 was primarily due to increased upstream production and refined product sales volumes resulting from the merger with Petro-Canada, higher price realizations due to stronger benchmark crude oil prices in the fourth quarter of 2009 compared to the same period in 2008, however these realizations were partially offset by realized losses of approximately $185 million after-tax on risk management derivative contracts, and increased production from Suncor's legacy oil sands operations resulting from improved operational reliability. These factors were partially offset by higher operating expenses that resulted from the merger with Petro-Canada and the increased production at our legacy oil sands operations, increased royalty expense due to the higher benchmark crude oil prices, and a fire at one of our upgraders in December 2009 which impacted overall production in the fourth quarter of 2009 by approximately 30,000 barrels per day.

"We started the year confronting one of the most challenging global economic downturns of the past century, but today Suncor is a larger, stronger and more financially flexible company as we continue to realize some significant synergies following the merger with Petro-Canada," said Rick George, president and chief executive officer. "We've made gains on achieving safe, reliable and cost-effective energy production across all our operations in 2009, which we intend to build on in 2010."

Net Earnings (Loss)
($ millions)

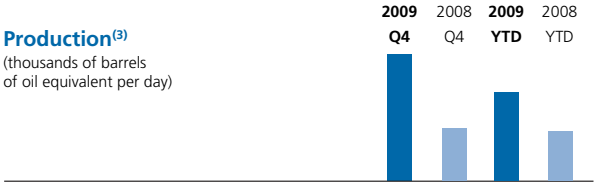
	2009 Q4	2008 Q4	2009 YTD	2008 YTD
Net earnings (loss)	**457**	(215)	**1,146**	2,137
Operating earnings[1]	**323**	14	**1,206**	2,534

Cash Flow from Operations by Quarter[2]
($ millions)



	2009 Q4	2008 Q4	2009 YTD	2008 YTD
	1,129	231	**2,799**	4,057

Production[3]
(thousands of barrels of oil equivalent per day)



	2009 Q4	2008 Q4	2009 YTD	2008 YTD
	638.2	279.4	**456.0**	264.7

Ratios
(percent)
for the twelve months ended December 31

	2009	2008
Return on average shareholder's equity	**5.1**	16.2
Return on capital employed[4]	**2.6**	21.1

(1) Non-GAAP measure. See page 2 for a reconciliation of net earnings to operating earnings.
(2) Non-GAAP measure. Calculation of this measure has been revised, and prior period comparative figures have been restated. See page 9.
(3) Includes Suncor's proportionate production share from the Syncrude joint venture.
(4) Non-GAAP measure. See page 9.

Operating Earnings

Operating earnings is a non-GAAP measure that the company uses to evaluate operating performance, which management believes allows better comparability between periods. Operating earnings is calculated by adjusting net earnings for significant one-time items and items that are not indicative of operating performance. See page 9 for discussion of non-GAAP financial measures.

	Three months ended December 31		Twelve months ended December 31	
($ millions, after-tax)	**2009**	2008	**2009**	2008
Net earnings (loss) as reported	**457**	(215)	**1 146**	2 137
Change in fair value of commodity derivatives used for risk management[1]	**(88)**	(372)	**499**	(372)
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(157)**	645	**(798)**	852
Mark-to-market valuation of stock-based compensation	**6**	(48)	**124**	(107)
Project start-up costs	**10**	4	**40**	24
Impact of income tax rate adjustments on future income tax liabilities[2]	**(148)**	—	**4**	—
Costs related to deferral of growth projects	**83**	—	**300**	—
Gain on effective settlement of pre-existing contract with Petro-Canada[3]	**—**	—	**(438)**	—
Impact of recording acquired inventory at fair value[4]	**—**	—	**97**	—
Merger and integration costs	**79**	—	**151**	—
Losses and adjustments on significant disposals[5]	**81**	—	**81**	—
Operating earnings	**323**	14	**1 206**	2 534

(1) Beginning in the fourth quarter of 2009, operating earnings is only adjusted for the impact of those commodity derivatives used for risk management purposes. It had previously included an adjustment for the change in fair value of all commodity derivatives. As the commodity derivatives relating to our energy trading activities are entered into for the purpose of earning energy trading revenues, any earnings impact relating to these derivatives will remain in operating earnings. The twelve months ended December 31, 2009 has been restated.

(2) In the fourth quarter of 2009, a reduction to the Ontario income tax rate resulted in a decrease in the future income tax liabilities (see note 14 of the December 31, 2009 unaudited interim consolidated financial statements). This was offset for the year ended December 31, 2009 by an increase in the future income tax liabilities resulting from a revised provincial allocation for income tax purposes due to the merger with Petro-Canada in the third quarter of 2009.

(3) Impact from deemed settlement value assigned to bitumen processing contract with Petro-Canada upon close of merger (see note 3f of the December 31, 2009 unaudited interim consolidated financial statements).

(4) Inventory acquired through the merger at fair value was sold during the third quarter of 2009, resulting in a one-time negative impact to earnings.

(5) Includes loss recognized when a highway interchange constructed by Suncor was transferred to the Provincial government of Alberta, and fair value adjustments to assets acquired in the merger.

Fourth Quarter 2009

Suncor's total upstream production during the fourth quarter of 2009 averaged 638,200 barrels of oil equivalent (boe) per day, including additional production of 325,600 boe per day resulting from the merger. Upstream production from Suncor's legacy oil sands and natural gas operations averaged 312,600 boe per day in the fourth quarter of 2009, compared to 279,400 boe per day in the fourth quarter of 2008.

Oil Sands production (excluding proportionate production share from the Syncrude joint venture) contributed an average 278,900 barrels per day (bpd) in the fourth quarter of 2009, compared to fourth quarter 2008 production of 243,800 bpd. Average production increased compared to the fourth quarter of 2008 as a result of improved operational reliability during the quarter. However, production volumes were negatively impacted by unplanned maintenance activities following the upgrader fire in December 2009.

Cash operating costs for our oil sands operations (excluding Syncrude) averaged $38.70 per barrel in the fourth quarter of 2009, compared to $41.30 per barrel during the fourth quarter of 2008. The decrease in cash operating costs per barrel was primarily due to increased production and a decrease in natural gas input prices. These factors were partially offset by an increase in operational expenses due to the inclusion of operating costs from MacKay River facilities in the fourth quarter of 2009. The merger with Petro-Canada did not result in increased oil sands production volumes (excluding Syncrude), as production from MacKay

River had been included in Suncor's reported production from January 1 to July 31, 2009 as volumes processed by Suncor under a processing fee agreement. Production from MacKay River averaged 31,700 bpd in the fourth quarter of 2009.

Suncor's proportionate production share from the Syncrude joint venture contributed an average 39,300 bpd of sweet synthetic crude production during the fourth quarter of 2009.

Production from Suncor's natural gas business during the fourth quarter of 2009 averaged 764 million cubic feet equivalent (mmcfe) per day. Production from Suncor's legacy natural gas operations averaged 202 mmcfe per day in the fourth quarter of 2009, compared to 213 mmcfe per day in the fourth quarter of 2008. This decrease in production was primarily due to shut-in production in the Elmworth area and the sale of certain non-core assets in the second quarter of 2009.

During the fourth quarter of 2009, East Coast Canada production contributed an average 63,600 bpd, while production from our International segment (comprising our assets in the North Sea and other international areas) averaged 129,000 bpd. Production for both the East Coast Canada and International segments was lower than capacity primarily as a result of planned and unplanned maintenance, as well as OPEC production quota constraints in Libya.

Refining and Marketing's fourth quarter earnings reflected the merger with Petro-Canada and the impact of strong retail margins. Sales of refined petroleum products for the fourth quarter averaged 82.9 million litres per day, which included 52.7 million litres per day resulting from the merger. Suncor's legacy refining and marketing operations averaged 30.2 million litres per day in the fourth quarter of 2009, compared to 31.5 million litres per day for the same period in 2008.

2009 Overview

At the company's annual and special meeting in June 2009, Suncor shareholders approved a merger with Petro-Canada. The merger subsequently closed on August 1, 2009, and Suncor became Canada's largest energy company and fifth largest North American-based energy company by market capitalization.

Net earnings for 2009 were $1.146 billion ($0.96 per common share), compared to $2.137 billion ($2.29 per common share) in 2008. Operating earnings in 2009 were $1.206 billion ($1.01 per common share), compared to $2.534 billion ($2.72 per common share) in 2008. Cash flow from operations was $2.799 billion in 2009, compared to $4.057 billion in 2008.

The decrease in 2009 operating earnings and cash flow from operations was primarily due to lower price realizations, as average benchmark commodity prices were significantly weaker in 2009 compared to 2008, in addition to realized losses of approximately $315 million after-tax on risk management derivative contracts as settlement prices were lower than benchmark prices for much of the year. These factors were partially offset by the increased upstream production and refined product sales volumes resulting from the merger with Petro-Canada, and improved operational performance from our existing oil sands assets.

After completion of the merger with Petro-Canada, Suncor's total upstream production during the final five months of 2009 averaged 635,200 boe per day, including additional production of 311,100 boe per day resulting from the merger.

Oil Sands production (excluding proportionate production share from the Syncrude joint venture) contributed an average 290,600 bpd in 2009, compared to 2008 production of 228,000 bpd. The increased production was primarily due to improved operational reliability in 2009, partially offset by unplanned maintenance activities following the upgrader fire in December 2009. Production in 2008 was negatively impacted by planned and unplanned maintenance shutdowns in our upgrading and extraction assets, as well as a regulatory imposed production cap on our Firebag in-situ operations. Syncrude operations contributed an average 38,500 bpd of sweet synthetic crude production in the last five months of 2009.

Oil Sands cash operating costs in 2009 (excluding Syncrude) averaged $33.95 per barrel, compared to $38.50 per barrel during 2008. The decrease in cash operating costs per barrel was primarily due to higher production and a decrease in natural gas input prices. These factors were partially offset by an increase in operational expenses due to the inclusion of operating costs from MacKay River facilities after completion of the merger.

Post-merger production from Suncor's natural gas business during the final five months of 2009 averaged 767 mmcfe per day. Production from Suncor's legacy natural gas operations averaged 210 mmcfe per day in 2009, compared to 220 mmcfe per day in 2008.

East Coast Canada production contributed an average 58,000 bpd during the final five months of 2009, while production from our International segment contributed an average 120,800 bpd in the same period. Production for both of these segments was lower than capacity primarily as a result of planned and unplanned maintenance, the tie-in of

the North Amethyst extension at White Rose, and OPEC production quota constraints in Libya.

Refining and Marketing's 2009 earnings reflected the positive impacts of the merger with Petro-Canada and improved operational reliability, partially offset by lower margins on light oil and decreased demand for refined petroleum products. Sales of refined petroleum products for the final five months averaged 84.8 million litres per day. Despite sales growth being constrained in 2009 by current economic conditions, total sales of refined petroleum products from Suncor's legacy refining and marketing operations averaged 32.6 million litres per day in 2009, compared to 31.5 million litres per day in 2008, reflecting increased refinery reliability.

Growth and Operational Update

In November 2009, Suncor's Board of Directors approved a $5.5 billion capital spending plan for 2010. Approximately $1.5 billion will be directed toward growth project funding, primarily at the company's oil sands operations, while $4 billion in spending is targeted to sustaining existing operations.

The majority of growth spending will be directed toward the Firebag Stage 3 in-situ oil sands expansion, which was approximately 50 per cent complete before being deferred in early 2009. Suncor now expects the project to begin production in the second quarter of 2011, with volumes then beginning to ramp up toward design capacity of approximately 68,000 bpd of bitumen over a period of approximately 18 months. Spending will also be directed to Firebag Stage 4 to support a target of first bitumen production in the fourth quarter of 2012. Stage 4 also has a design capacity of 68,000 bpd.

"These are the first steps in our strategic plan to steadily increase oil sands production as we embark on a period of disciplined, but significant growth," said George. "Suncor enjoys the luxury of having more growth opportunity than we can immediately execute, so it's really a matter of ranking these opportunities and making sure we proceed with the right project at the right time and in the right way."

Growth capital will also be directed toward completing a naphtha unit in one of our upgraders and to the expansion of Suncor's St. Clair Ethanol Plant. International growth capital plans include commitments in Libya and investments planned to bring the Ebla gas project in Syria into production in the second quarter of 2010.

Capital plans and sequencing for other projects in Suncor's growth portfolio are under evaluation with a further update expected in the fourth quarter of 2010.

The company continues to incur costs related to placing certain growth projects into "safe mode" as a result of the company revising its 2009 capital budget due to market conditions earlier in the year. 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. As a result of placing the company's projects into safe mode, pre-tax costs of $382 million were incurred in 2009. Further safe mode costs of $150 million to $200 million on a pre-tax basis are expected to be incurred in 2010.

As part of its strategic business alignment, Suncor announced its intention to divest of a number of non-core assets. The proposed divestments identified to date include certain natural gas assets in Western Canada and the United States Rockies, all Trinidad and Tobago assets and certain non-core North Sea assets, including all assets in The Netherlands.

On December 31, 2009, Suncor entered into an agreement to sell substantially all of its oil and gas producing assets in the United States Rockies for proceeds of $517 million (US$494 million), which is approximately equal to its net book value at December 31, 2009. The sale is expected to close in March 2010.

"As a result of the recent merger, Suncor now holds the largest single position in the oil sands industry," said George. "The combination of strategic investment in oil sands growth projects and strategic divestment of non-core assets will mean a steady shift in balance in favour of what has always been Suncor's core business."

In conjunction with the merger with Petro-Canada, the Competition Bureau of Canada required Suncor to divest 104 retail sites in Ontario. On December 8, 2009, Suncor entered into an agreement with Husky Energy whereby Suncor agreed to sell 98 sites with expected closing dates commencing in the first half of 2010 as ownership of individual sites is transferred to the purchaser.

While the timeline for the divestment of assets remains flexible, Suncor expects most of the sales to occur during 2010. Divestment proceeds will be used to reduce the company's debt.

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

Project	Business Segment	Plan	Cost Estimate $ millions (1)	Estimate % Accuracy (1)	Spent to date	Target completion date
Firebag sulphur plant	Oil Sands	Support emission abatement plan at Firebag; capacity to support Stages 1-6	404	N/A	415	Complete
Steepbank extraction plant	Oil Sands	New location and technologies aimed at improving operational performance	980	N/A	1 015	Complete
Ebla gas project	International	Development of gas fields and construction of gas treatment plant	1 196	+7/−3	1 080	Q2 2010
Buzzard Enhancement Project (2)	International	Installation of equipment to handle high sulphur content	339	+15/−10	163	Q4 2010
Firebag Stage 3	Oil Sands	Expansion is expected to increase bitumen supply	3 638	+10/−10	2 780	Q2 2011
Naphtha unit	Oil Sands	Increases sweet product mix	850	+4/−4	670	Q3 2011
North Amethyst (2)	East Coast Canada	Extension to the White Rose field involving sub-sea tie-in	490	+10/−5	230	2012 (3)

(1) Cost estimates and estimate accuracy reflect budgets approved at the time the project was sanctioned by Suncor's Board of Directors.

(2) Amounts represent Suncor's net share in the project

(3) Initial production is expected in the second quarter of 2010.

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 and page 18 of legacy Petro-Canada's 2008 Annual Report. For additional information on risks, uncertainties and other factors that could cause actual results to differ, please see page 11.

The material factors used to develop target completion dates and cost estimates include: 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.

Outlook

Suncor's outlook provides management's targets for 2010 in certain key areas of the company's business. Users of this forward-looking information are cautioned that actual results may vary from the targets disclosed.

	2010 Full Year Outlook
Total production (boe per day) – before targeted divestitures[1]	644,000
Total production (boe per day) – related to targeted divestitures[1]	75,000
Oil Sands[2]	
Production (bpd)	300,000 (+/−5%)
Sales	
Diesel	8%
Sweet	39%
Sour	46%
Bitumen	7%
Realization on crude sales basket[3]	WTI @ Cushing less Cdn$4.75 to Cdn$5.75 per barrel
Cash operating costs[4]	$35 to $39 per barrel
Syncrude production (bpd)	38,000 (+/−5%)
Natural Gas	
Production[5] (mmcfe per day) – before targeted divestitures[1]	680 (+/−5%)
Production[5] (mmcfe per day) – related to targeted divestitures[1]	300
Natural gas	91%
Crude oil and liquids	9%
East Coast Canada	
Production (bpd)	55,000 (+/−5%)
International	
Production (boe per day) – before targeted divestitures[1]	138,000 (+/−5%)
Production (boe per day) – related to targeted divestitures[1]	25,000
Crude oil and liquids	87%
Natural gas	13%

(1) Actual production results may be impacted by the timing of planned divestments.

(2) Excludes Suncor's proportionate production share from the Syncrude joint venture.

(3) Excludes the impact of hedging activities.

(4) Cash operating cost estimates (excluding Syncrude) 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 $5.00 per gigajoule ($5.28 per mcf) at AECO. This estimate does not include costs related to deferral of growth projects.

(5) 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.

This outlook is based on Suncor's current estimates, projections and assumptions for the 2010 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 for the Oil Sands 2010 full year outlook include reliability and operational efficiency initiatives which we expect to minimize unplanned maintenance in 2010. Natural Gas, East Coast Canada and International 2010 outlook numbers include assumptions related to reservoir performance, drilling results, facility reliability, changes in OPEC production quotas, and execution of planned turnarounds within allotted time frames.

Factors that could potentially impact Suncor's operations and financial performance for 2010 include:

- Bitumen supply. Ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage and in-situ reservoir performance could impact 2010 production targets.
- Performance of recently commissioned 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, pipeline, or offshore assets.
- Planned maintenance. Production estimates could be impacted due to unexpected events impacting the timing or duration of planned maintenance.
- Planned divestitures. Our inability to execute planned divestitures could impact our debt management and capital expenditure plans.
- Commodity prices. Significant declines in natural gas commodity prices could result in the shut-in of some of our natural gas production.
- Foreign operations. Suncor's foreign operations and related assets are subject to a number of political, economic and socio-economic risks. Suncor's operations in Libya may be constrained by OPEC quotas.

The preceding paragraphs and tables contain forward-looking information that is subject to a number of risks and uncertainties, many of which are beyond the company's control. For additional information on risks, uncertainties and other factors that could cause actual results to differ, please see page 11.

Cash Income Taxes

We estimate we will have cash income taxes of approximately $800 million to $900 million during 2010. 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 tables on page 7 and 8, assuming there are no changes to the current income tax regime. Our outlook on cash income taxes is a forward-looking statement and users of this information are cautioned that actual cash income taxes may vary materially from our outlook.

Oil Sands Crown Royalties

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

The following table sets forth an estimation of royalties on our oil sands operations (excluding Syncrude) in the years 2010 - 2013 for three price scenarios, and certain assumptions on which we have based our estimates for those price scenarios.

WTI Price/bbl US$	**60**	**80**	**100**
Natural gas (Alberta spot) Cdn$/mcf at AECO	5.75	7.50	9.50
Light/heavy oil differential of WTI at Cushing less Maya at the U.S. Gulf Coast US$	7.25	9.75	12.00
Differential of Maya at the U.S. Gulf Coast less Western Canadian Select at Hardisty, Alberta US$	4.50	6.00	7.50
US$/Cdn$ exchange rate	0.85	0.97	1.00
Crown Royalty Expense (based on percentage of total Oil Sands gross revenue)% (1)			
2010-2013 – Bitumen (new rates – with limits for mining only 30% and 1% min)	4-6	9-11	12-14

(1) Reflects Crown's interim bitumen valuation methodology

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

(i) The government of Alberta enacted new Bitumen Valuation Methodology (Ministerial) Regulations as part of the implementation of the New Royalty Framework

effective January 1, 2009. These interim regulations determine the valuation of bitumen for 2009 and 2010. The final regulations are being developed by the Crown that will establish the bitumen valuation methodology for future years. For Suncor's mining operations, the bitumen valuation methodology is based on the terms of Suncor's January 2008 Royalty Amending Agreement (RAA), which we believe places certain limitations on the interim bitumen valuation methodology as recently enacted. For the year 2009, Suncor filed a non-compliance notice with the Crown, citing that reasonable adjustments in the determination of the Suncor bitumen value were not considered by the Crown as permitted by the Suncor RAA. Royalty payments to the Crown for our mining operations were determined in accordance with the Suncor RAA and royalty expense was recorded under the Crown's interim bitumen valuation methodology, representing a negative difference of approximately $200 million. The Suncor RAA provides for a negotiation period with the Crown and failing a negotiated settlement, an arbitration procedure is outlined. If a negotiated settlement or arbiter does not create a result in Suncor's favour, royalty payments could be significantly higher.

(ii) The government enacted the new Oil Sands Allowed Costs (Ministerial) 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 Suncor's January 2008 Royalty Amending Agreement determine the royalty obligation through 2015 for the mining operations. However, potential changes to, and the interpretation of, the Allowed Cost regulations, could over time, have a significant impact on the amount of royalties payable.

(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 Annual Information Form dated March 2, 2009.

Syncrude Royalties

Syncrude oil sands project ("Syncrude") is also subject to the New Royalty Framework effective January 1, 2009 and has signed a Royalty Amending Agreement with the Crown. Syncrude has also filed a non-compliance notice with the Crown with respect to the valuation of bitumen for royalty purposes. The royalty adjustment amount for Suncor's share of the Syncrude project is not material.

East Coast Canada Royalties

The following table sets forth an estimation of royalties on our East Coast Canada operations in 2010 for three price scenarios, and certain assumptions on which we have based our estimates for those price scenarios.

WTI Price/bbl US$	**60**	**80**	**100**
US$/Cdn$ exchange rate	0.85	0.97	1.00
Crown Royalty Expense (based on percentage of gross revenue)%			
2010 – Crude (tiered royalty rates assessed on gross or net revenue)	29-31	31-33	32-34

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 Newfoundland and Labrador, current forecasts of production, capital and operating costs, and the forward estimates of commodity prices and exchange rates described in the table.

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

(i) The government of Newfoundland and Labrador and Suncor are in discussions to resolve several outstanding issues that impact current and prior years. Settlement of these issues could impact royalties payable to the Crown.

(ii) Changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and

operating costs for each project; changes resulting from regulatory audits of prior year filings; further changes to applicable royalty regimes by the government of Newfoundland and Labrador; changes in other legislation and the occurrence of unexpected events all have the potential to have an impact on royalties payable to the Crown.

Non-GAAP Financial Measures

Certain financial measures referred to in this report to shareholders, namely operating earnings, 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.

Operating earnings (loss) represent net earnings (loss) excluding the change in fair value of commodity derivatives used for risk management, unrealized foreign exchange gain (loss) on U.S. dollar denominated long term debt, mark-to-market valuation of stock-based compensation, impact of income tax rate adjustments on future income tax liabilities, costs related to start-up or deferral of growth projects, and impacts related to the merger with Petro-Canada. Operating earnings are used by the Company to evaluate operating performance. See page 2 for a reconciliation of net earnings to operating earnings.

Cash flow from operations is expressed before changes in non-cash working capital. Cash flow from operations is the same measure as the cash flow from operating activities before changes in working capital measure that is included in the unaudited interim consolidated financial statements. Beginning in third quarter 2009, cash flow from operations adjusts for the impact of fair value changes on both the current and long-term portions of commodity derivatives and stock-based compensation (previously only adjusted the impact on the long-term portions). The company believes this provides more useful information to investors and allows better comparability between Suncor and other companies with similar adjustments for commodity derivatives and/or stock-based compensation. Prior period comparative figures have been restated. A reconciliation of net earnings to cash flow from operating activities before changes in working capital is provided in the Statement of Cash Flows and Schedules of Segmented Data, which are included in Suncor's December 31, 2009 unaudited interim consolidated financial statements.

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 December 31, 2009 interim basis, please refer to page 35 of Suncor's December 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:

	Three months ended December 31		Twelve months ended December 31	
	2009	2008	**2009**	2008
Cash flow from operations ($ millions)	**1 129**	231	**2 799**	4 057
Weighted number of shares outstanding – basic (millions of shares)	**1 560**	935	**1 198**	932
Cash flow from operations – basic ($ per share)	**0.72**	0.25	**2.34**	4.36

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[1]

	Three months ended December 31				Twelve months ended December 31			
	2009		2008		**2009**		2008	
(unaudited)	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses	**1 300**		991		**4 277**		3 204	
Less: Natural gas costs, inventory changes, stock-based compensation, and other	**(164)**		(183)		**(400)**		(524)	
Less: Safe mode costs	**(120)**		—		**(380)**		—	
Less: Non-monetary transactions	**(10)**		(30)		**(66)**		(111)	
Less: Syncrude-related operating, selling and general expenses	**(133)**		—		**(199)**		—	
Accretion of asset retirement obligations	**27**		14		**107**		55	
Cash costs	**900**	**35.10**	792	35.35	**3 339**	**31.50**	2 624	31.45
Natural gas	**88**	**3.40**	91	4.05	**252**	**2.40**	438	5.25
Imported bitumen (excluding other reported product purchases)	**5**	**0.20**	43	1.90	**8**	**0.05**	150	1.80
Cash operating costs	**993**	**38.70**	926	41.30	**3 599**	**33.95**	3 212	38.50
Project start-up costs	**13**	**0.50**	6	0.30	**51**	**0.45**	35	0.40
Total cash operating costs	**1 006**	**39.20**	932	41.60	**3 650**	**34.40**	3 247	38.90
Depreciation, depletion and amortization	**257**	**10.00**	168	7.50	**850**	**8.00**	580	6.95
Total operating costs	**1 263**	**49.20**	1 100	49.10	**4 500**	**42.40**	3 827	45.85
Production excluding Syncrude (thousands of barrels per day)	**278.9**		243.8		**290.6**		228.0	

(1) Excludes Suncor's proportionate production share and operating costs from the Syncrude joint venture

Notice – Forward-Looking Information

This report to shareholders 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. These statements and information are subject to a number of risks and uncertainties, many of which are beyond the company's control.

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," "will" 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 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 2010 outlook, see page 6.

Certain financial measures referred to in this report to shareholders, namely operating earnings, 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. For a further description of these measures please refer to page 9.

The risks, uncertainties and other factors that could influence actual results include but are not limited to, those risks, uncertainties and other factors described throughout this report to shareholders and: 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; Suncor's inability to execute planned divestitures; political, economic and socio-economic risk associated with foreign operations (including OPEC production quotas); 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; 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; failure to realize anticipated synergies or cost savings; risks regarding the integration of Petro-Canada and incorrect assessments of the value of Petro-Canada. The foregoing important factors are not exhaustive.

Many of these risk factors are discussed in further detail throughout Suncor's fourth quarter 2009 Report to Shareholders and in Suncor's and legacy Petro-Canada's Annual Information Form/Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission (SEC) at www.sec.gov. Readers are also referred to the risk factors described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

Consolidated Statements of Earnings

(unaudited)

($ millions)	Three months ended December 31 2009	2008	Twelve months ended December 31 2009	2008
Revenues				
Operating revenues	**7 537**	3 982	**18 658**	18 179
Less: Royalties	**(587)**	(86)	**(1 199)**	(890)
Operating revenues (net of royalties)	**6 950**	3 896	**17 459**	17 289
Energy trading activities (note 5)	**681**	3 053	**7 577**	11 320
Interest and other income (note 3f)	**5**	3	**444**	28
	7 636	6 952	**25 480**	28 637
Expenses				
Purchases of crude oil and products	**2 881**	1 744	**7 383**	7 582
Operating, selling and general (note 9)	**2 358**	1 226	**6 641**	4 186
Energy trading activities (note 5)	**524**	3 051	**7 381**	11 323
Transportation costs	**167**	94	**427**	246
Depreciation, depletion and amortization	**1 072**	286	**2 306**	1 049
Accretion of asset retirement obligations	**52**	16	**155**	64
Exploration	**100**	17	**268**	90
Loss on disposal of assets	**54**	27	**66**	13
Project start-up costs	**13**	6	**51**	35
Financing expenses (income) (note 7)	**(70)**	676	**(487)**	917
	7 151	7 143	**24 191**	25 505
Earnings (Loss) Before Income Taxes	**485**	(191)	**1 289**	3 132
Provisions for (Recovery of) Income Taxes (note 14)				
Current	**215**	108	**868**	514
Future	**(187)**	(84)	**(725)**	481
	28	24	**143**	995
Net Earnings (Loss)	**457**	(215)	**1 146**	2 137
Net Earnings (Loss) Per Common Share (dollars), (note 8)				
Basic	**0.29**	(0.24)	**0.96**	2.29
Diluted	**0.29**	(0.24)	**0.95**	2.26
Cash dividends	**0.10**	0.05	**0.30**	0.20

Consolidated Statements of Comprehensive Income

(unaudited)

($ millions)	Three months ended December 31 2009	2008	Twelve months ended December 31 2009	2008
Net earnings (loss)	**457**	(215)	**1 146**	2 137
Other comprehensive income (loss), net of tax				
Change in foreign currency translation adjustment	**(82)**	257	**(332)**	350
Gain (loss) on derivative contracts designated as cash flow hedges	**(1)**	2	**2**	—
Comprehensive Income	**374**	44	**816**	2 487

Consolidated Balance Sheets

(unaudited)

($ millions)	**December 31 2009** (note 3)	December 31 2008 (restated)
Assets		
Current assets		
Cash and cash equivalents	**505**	660
Accounts receivable	**3 936**	1 580
Inventories	**2 971**	909
Income taxes receivable	**587**	67
Future income taxes	**332**	21
Total current assets	**8 331**	3 237
Property, plant and equipment, net (note 2)	**57 485**	28 882
Other assets (note 2)	**536**	388
Goodwill (note 3)	**3 201**	21
Future income taxes	**193**	—
Total assets	**69 746**	32 528
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**2**	2
Current portion of long-term debt (note 12)	**25**	18
Accounts payable and accrued liabilities	**6 322**	3 326
Income taxes payable	**1 274**	81
Future income taxes	**18**	111
Total current liabilities	**7 641**	3 538
Long-term debt (note 12)	**13 855**	7 866
Accrued liabilities and other	**5 269**	1 986
Future income taxes (note 14)	**8 870**	4 615
Shareholders' equity (see below)	**34 111**	14 523
Total liabilities and shareholders' equity	**69 746**	32 528

Shareholders' Equity

	Number (thousands)		Number (thousands)	
Share capital (note 9)	**1 559 778**	**20 053**	935 524	1 113
Contributed surplus		**526**		288
Accumulated other comprehensive income (loss) (note 13)		**(233)**		97
Retained earnings		**13 765**		13 025
Total shareholders' equity		**34 111**		14 523

Consolidated Statements of Cash Flows

(unaudited)

($ millions)	Three months ended December 31 2009	Three months ended December 31 2008	Twelve months ended December 31 2009	Twelve months ended December 31 2008
Operating Activities				
Net earnings (loss)	**457**	(215)	**1 146**	2 137
Adjustments for:				
Depreciation, depletion and amortization	**1 072**	286	**2 306**	1 049
Future income taxes	**(187)**	(84)	**(725)**	481
Accretion of asset retirement obligations	**52**	16	**155**	64
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(201)**	681	**(858)**	919
Change in fair value of derivative contracts	**(59)**	(507)	**980**	(638)
Loss on disposal of assets	**54**	27	**66**	13
Stock-based compensation	**34**	(36)	**262**	(22)
Gain on effective settlement of pre-existing contract with Petro-Canada (note 3f)	**—**	—	**(438)**	—
Other	**(151)**	50	**(278)**	(7)
Exploration expenses	**58**	13	**183**	61
Cash flow from operating activities before changes in non-cash working capital	**1 129**	231	**2 799**	4 057
Decrease (increase) in non-cash working capital related to operating activities (note 15)	**344**	988	**(224)**	405
Cash flow from operating activities	**1 473**	1 219	**2 575**	4 462
Investing Activities				
Capital and exploration expenditures	**(1 556)**	(2 670)	**(4 246)**	(7 987)
Deferred outlays and other investments	**(3)**	(15)	**(30)**	(51)
Cash acquired through business combination (net) (note 3d)	**—**	—	**248**	—
Proceeds from disposals	**112**	—	**148**	33
Decrease (increase) in non-cash working capital related to investing activities	**(83)**	176	**(791)**	415
Cash flow used in investing activities	**(1 530)**	(2 509)	**(4 671)**	(7 590)
Net cash deficiency before financing activities	**(57)**	(1 290)	**(2 096)**	(3 128)
Financing Activities				
Decrease in short-term debt	**(1)**	—	**—**	(1)
Net proceeds from issuance of long-term debt	**—**	—	**—**	2 704
Net increase (decrease) in long-term debt	**116**	617	**2 325**	422
Issuance of common shares under stock option plan	**11**	6	**41**	190
Dividends paid on common shares	**(152)**	(46)	**(401)**	(180)
Cash flow provided by (used in) financing activities	**(26)**	577	**1 965**	3 135
Increase (Decrease) in Cash and Cash Equivalents	**(83)**	(713)	**(131)**	7
Effect of Foreign Exchange on Cash and Cash Equivalents	**1**	58	**(24)**	84
Cash and Cash Equivalents at Beginning of Period	**587**	1 315	**660**	569
Cash and Cash Equivalents at End of Period	**505**	660	**505**	660

Consolidated Statements of Changes in Shareholders' Equity

(unaudited)

($ millions)	Share Capital	Contributed Surplus	Accumulated Other Comprehensive Income (Loss)	Retained Earnings
At December 31, 2007	881	194	(253)	11 074
Net earnings	—	—	—	2 137
Dividends paid on common shares	—	—	—	(180)
Issued for cash under stock option plan	226	(36)	—	—
Issued under dividend reinvestment plan	6	—	—	(6)
Stock-based compensation expense	—	120	—	—
Income tax benefit of stock option deduction in the U.S.	—	10	—	—
Change in accumulated other comprehensive income (loss)	—	—	350	—
At December 31, 2008	1 113	288	97	13 025
Net earnings	**—**	**—**	**—**	**1 146**
Dividends paid on common shares	**—**	**—**	**—**	**(401)**
Issued for cash under stock option plans	**57**	**(16)**	**—**	**—**
Issued under dividend reinvestment plan	**5**	**—**	**—**	**(5)**
Stock-based compensation expense	**—**	**103**	**—**	**—**
Issued for Petro-Canada acquisition (note 3c)	**18 878**	**—**	**—**	**—**
Fair value of Petro-Canada stock options exchanged for Suncor stock options (note 3c)	**—**	**147**	**—**	**—**
Income tax benefit of stock option deduction in the U.S.	**—**	**4**	**—**	**—**
Change in accumulated other comprehensive income (loss)	**—**	**—**	**(330)**	**—**
At December 31, 2009	**20 053**	**526**	**(233)**	**13 765**

Schedules of Segmented Data

(unaudited)

												Three months ended December 31		
	Oil Sands		Natural Gas		East Coast Canada		International		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
($ millions)	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008
EARNINGS														
Revenues														
Operating revenues	**1 182**	2 048	**279**	124	**374**	—	**966**	—	**4 733**	1 803	**3**	7	**7 537**	3 982
Less: Royalties	**(280)**	(54)	**(53)**	(32)	**(154)**	—	**(100)**	—	**—**	—	**—**	—	**(587)**	(86)
Operating revenues (net of royalties)	**902**	1 994	**226**	92	**220**	—	**866**	—	**4 733**	1 803	**3**	7	**6 950**	3 896
Energy trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**681**	3 053	**681**	3 053
Intersegment revenues	**1 082**	264	**91**	13	**62**	—	**—**	—	**49**	—	**(1 284)**	(277)	**—**	—
Interest and other income	**2**	—	**—**	—	**—**	—	**1**	—	**—**	1	**2**	2	**5**	3
	1 986	2 258	**317**	105	**282**	—	**867**	—	**4 782**	1 804	**(598)**	2 785	**7 636**	6 952
Expenses														
Purchases of crude oil and products	**83**	238	**—**	—	**17**	—	**—**	—	**3 930**	1 822	**(1 149)**	(316)	**2 881**	1 744
Operating, selling and general	**1 300**	991	**125**	32	**41**	—	**181**	—	**518**	199	**193**	4	**2 358**	1 226
Energy trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**524**	3 051	**524**	3 051
Transportation costs	**70**	89	**27**	4	**11**	—	**21**	—	**43**	6	**(5)**	(5)	**167**	94
Depreciation, depletion and amortization	**300**	168	**190**	56	**134**	—	**322**	—	**115**	54	**11**	8	**1 072**	286
Accretion of asset retirement obligations	**29**	14	**10**	2	**3**	—	**10**	—	**—**	—	**—**	—	**52**	16
Exploration	**2**	1	**44**	16	**4**	—	**50**	—	**—**	—	**—**	—	**100**	17
Loss on disposal of assets	**53**	23	**—**	—	**—**	—	**—**	—	**1**	4	**—**	—	**54**	27
Project start-up costs	**13**	6	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**13**	6
Financing expenses (income)	**1**	—	**—**	—	**1**	—	**(1)**	—	**4**	—	**(75)**	676	**(70)**	676
	1 851	1 530	**396**	110	**211**	—	**583**	—	**4 611**	2 085	**(501)**	3 418	**7 151**	7 143
Earnings (loss) before income taxes	**135**	728	**(79)**	(5)	**71**	—	**284**	—	**171**	(281)	**(97)**	(633)	**485**	(191)
Income taxes	**101**	(153)	**29**	5	**2**	—	**(151)**	—	**(13)**	107	**4**	17	**(28)**	(24)
Net earnings (loss)	**236**	575	**(50)**	—	**73**	—	**133**	—	**158**	(174)	**(93)**	(616)	**457**	(215)

Schedules of Segmented Data (continued)

(unaudited)

											Three months ended December 31			
	Oil Sands		Natural Gas		East Coast Canada		International		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
($ millions)	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008
CASH FLOW BEFORE FINANCING ACTIVITIES														
Operating activities:														
Net earnings (loss)	**236**	575	**(50)**	—	**73**	—	**133**	—	**158**	(174)	**(93)**	(616)	**457**	(215)
Adjustments for:														
Depreciation, depletion and amortization	**300**	168	**190**	56	**134**	—	**322**	—	**115**	54	**11**	8	**1 072**	286
Future income taxes	**(103)**	20	**(29)**	(5)	**(2)**	—	**(39)**	—	**6**	(79)	**(20)**	(20)	**(187)**	(84)
Accretion of asset retirement obligations	**29**	14	**10**	2	**3**	—	**10**	—	**—**	—	**—**	—	**52**	16
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(201)**	681	**(201)**	681
Change in fair value of derivative contracts	**(28)**	(509)	**1**	1	**—**	—	**—**	—	**5**	22	**(37)**	(21)	**(59)**	(507)
Loss on disposal of assets	**53**	23	**—**	—	**—**	—	**—**	—	**1**	4	**—**	—	**54**	27
Stock-based compensation	**14**	(5)	**4**	—	**—**	—	**1**	—	**5**	—	**10**	(31)	**34**	(36)
Other	**(146)**	35	**(8)**	(4)	**(3)**	—	**10**	—	**(22)**	(8)	**18**	27	**(151)**	50
Exploration expenses	**—**	—	**42**	13	**—**	—	**16**	—	**—**	—	**—**	—	**58**	13
Cash flow from (used in) operating activities before changes in non-cash working capital	**355**	321	**160**	63	**205**	—	**453**	—	**268**	(181)	**(312)**	28	**1 129**	231
Decrease (increase) in non-cash working capital related to operating activities	**1 321**	744	**(7)**	2	**(66)**	—	**(93)**	—	**314**	517	**(1 125)**	(275)	**344**	988
Total cash flow from (used in) operating activities	**1 676**	1 065	**153**	65	**139**	—	**360**	—	**582**	336	**(1 437)**	(247)	**1 473**	1 219
Investing activities:														
Capital and exploration expenditures	**(734)**	(2 492)	**(66)**	(96)	**(60)**	—	**(396)**	—	**(256)**	(74)	**(44)**	(8)	**(1 556)**	(2 670)
Deferred outlays and other investments	**(1)**	(2)	**—**	—	**—**	—	**—**	—	**(3)**	(11)	**1**	(2)	**(3)**	(15)
Cash acquired through business combination (net)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Proceeds from disposals	**96**	—	**—**	—	**—**	—	**—**	—	**16**	—	**—**	—	**112**	—
Decrease (increase) in investing working capital	**(112)**	174	**(6)**	—	**(28)**	—	**66**	—	**(3)**	(5)	**—**	7	**(83)**	176
Total cash (used in) from investing activities	**(751)**	(2 320)	**(72)**	(96)	**(88)**	—	**(330)**	—	**(246)**	(90)	**(43)**	(3)	**(1 530)**	(2 509)
Net cash surplus (deficiency) before financing activities	**925**	(1 255)	**81**	(31)	**51**	—	**30**	—	**336**	246	**(1 480)**	(250)	**(57)**	(1 290)

Schedules of Segmented Data

(unaudited)

											Twelve months ended December 31			
	Oil Sands		Natural Gas		East Coast Canada		International		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
($ millions)	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008
EARNINGS														
Revenues														
Operating revenues	**4 135**	8 045	**612**	696	**499**	—	**1 434**	—	**11 962**	9 418	**16**	20	**18 658**	18 179
Less: Royalties	**(645)**	(715)	**(85)**	(175)	**(217)**	—	**(252)**	—	**—**	—	**—**	—	**(1 199)**	(890)
Operating revenues (net of royalties)	**3 490**	7 330	**527**	521	**282**	—	**1 182**	—	**11 962**	9 418	**16**	20	**17 459**	17 289
Energy trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**7 577**	11 320	**7 577**	11 320
Intersegment revenues	**2 609**	1 309	**154**	58	**159**	—	**—**	—	**51**	—	**(2 973)**	(1 367)	**—**	—
Interest and other income	**440**	—	**—**	—	**—**	—	**1**	—	**—**	1	**3**	27	**444**	28
	6 539	8 639	**681**	579	**441**	—	**1 183**	—	**12 013**	9 419	**4 623**	10 000	**25 480**	28 637
Expenses														
Purchases of crude oil and products	**325**	574	**—**	—	**33**	—	**—**	—	**9 731**	8 472	**(2 706)**	(1 464)	**7 383**	7 582
Operating, selling and general	**4 277**	3 203	**322**	160	**72**	—	**242**	—	**1 279**	746	**449**	77	**6 641**	4 186
Energy trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**7 381**	11 323	**7 381**	11 323
Transportation costs	**248**	229	**58**	17	**19**	—	**33**	—	**87**	16	**(18)**	(16)	**427**	246
Depreciation, depletion and amortization	**922**	580	**448**	225	**184**	—	**400**	—	**323**	202	**29**	42	**2 306**	1 049
Accretion of asset retirement obligations	**111**	55	**22**	8	**4**	—	**17**	—	**1**	1	**—**	—	**155**	64
Exploration	**10**	17	**127**	73	**4**	—	**127**	—	**—**	—	**—**	—	**268**	90
Loss (gain) on disposal of assets	**70**	36	**(20)**	(22)	**—**	—	**—**	—	**16**	6	**—**	(7)	**66**	13
Project start-up costs	**51**	35	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**51**	35
Financing expenses (income)	**1**	—	**—**	—	**1**	—	**(1)**	—	**4**	—	**(492)**	917	**(487)**	917
	6 015	4 729	**957**	461	**317**	—	**818**	—	**11 441**	9 443	**4 643**	10 872	**24 191**	25 505
Earnings (loss) before income taxes	**524**	3 910	**(276)**	118	**124**	—	**365**	—	**572**	(24)	**(20)**	(872)	**1 289**	3 132
Income taxes	**33**	(1 035)	**77**	(29)	**(12)**	—	**(200)**	—	**(139)**	19	**98**	50	**(143)**	(995)
Net earnings (loss)	**557**	2 875	**(199)**	89	**112**	—	**165**	—	**433**	(5)	**78**	(822)	**1 146**	2 137
As at December 31														
TOTAL ASSETS	**37 553**	25 795	**5 003**	1 862	**4 771**	—	**9 913**	—	**10 568**	4 687	**1 938**	184	**69 746**	32 528

Schedules of Segmented Data (continued)

(unaudited)

											Twelve months ended December 31			
	Oil Sands		Natural Gas		East Coast Canada		International		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
($ millions)	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008
CASH FLOW BEFORE FINANCING ACTIVITIES														
Operating activities:														
Net earnings (loss)	**557**	2 875	**(199)**	89	**112**	—	**165**	—	**433**	(5)	**78**	(822)	**1 146**	2 137
Adjustments for:														
Depreciation, depletion and amortization	**922**	580	**448**	225	**184**	—	**400**	—	**323**	202	**29**	42	**2 306**	1 049
Future income taxes	**(643)**	535	**(52)**	15	**12**	—	**(56)**	—	**109**	(7)	**(95)**	(62)	**(725)**	481
Accretion of asset retirement obligations	**111**	55	**22**	8	**4**	—	**17**	—	**1**	1	**—**	—	**155**	64
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(858)**	919	**(858)**	919
Change in fair value of derivative contracts	**960**	(590)	**—**	—	**—**	—	**—**	—	**(14)**	27	**34**	(75)	**980**	(638)
Loss (gain) on disposal of assets	**70**	36	**(20)**	(22)	**—**	—	**—**	—	**16**	6	**—**	(7)	**66**	13
Stock-based compensation	**90**	54	**19**	4	**2**	—	**10**	—	**35**	16	**106**	(96)	**262**	(22)
Gain on effective settlement of pre-existing contract with Petro-Canada	**(438)**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(438)**	—
Other	**(378)**	(38)	**(11)**	(13)	**21**	—	**19**	—	**60**	8	**11**	36	**(278)**	(7)
Exploration expenses	**—**	—	**122**	61	**—**	—	**61**	—	**—**	—	**—**	—	**183**	61
Cash flow from (used in) operating activities before changes in non-cash working capital	**1 251**	3 507	**329**	367	**335**	—	**616**	—	**963**	248	**(695)**	(65)	**2 799**	4 057
Decrease (increase) in operating working capital	**(202)**	934	**(9)**	43	**(34)**	—	**(35)**	—	**(270)**	292	**326**	(864)	**(224)**	405
Total cash flow from (used in) operating activities	**1 049**	4 441	**320**	410	**301**	—	**581**	—	**693**	540	**(369)**	(929)	**2 575**	4 462
Investing activities:														
Capital and exploration expenditures	**(2 807)**	(7 391)	**(320)**	(342)	**(123)**	—	**(543)**	—	**(409)**	(226)	**(44)**	(28)	**(4 246)**	(7 987)
Deferred outlays and other investments	**(36)**	(39)	**—**	—	**—**	—	**—**	—	**(3)**	(11)	**9**	(1)	**(30)**	(51)
Cash acquired through business combination (net)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**248**	—	**248**	—
Proceeds from disposals	**96**	—	**27**	26	**—**	—	**—**	—	**25**	—	**—**	7	**148**	33
Decrease (increase) in investing working capital	**(799)**	434	**(19)**	—	**(29)**	—	**60**	—	**(4)**	(19)	**—**	—	**(791)**	415
Total cash (used in) from investing activities	**(3 546)**	(6 996)	**(312)**	(316)	**(152)**	—	**(483)**	—	**(391)**	(256)	**213**	(22)	**(4 671)**	(7 590)
Net cash surplus (deficiency) before financing activities	**(2 497)**	(2 555)	**8**	94	**149**	—	**98**	—	**302**	284	**(156)**	(951)	**(2 096)**	(3 128)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

1. ACCOUNTING POLICIES

These interim consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and follow the same accounting policies and methods of computation as, and should be read in conjunction with, the most recent annual financial statements, except for the accounting policy changes as described in note 2, 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 December 31, 2009 and 2008, and the results of its operations and cash flows for the three and twelve month periods ended December 31, 2009 and 2008.

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

2. 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. At December 31, 2008, property, plant and equipment was increased by $561 million, with an equal and offsetting reduction to other assets.

(b) Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

On January 1, 2009, the company adopted the recommendations of CICA Emerging Issues Committee Abstract 173 relating to the fair value of financial assets and liabilities. The Abstract requires that an entity's own credit risk and the credit risk of the counterparty are taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. The Abstract is to be applied retroactively without restatement of prior periods. The company has evaluated the new Abstract and concluded that the adoption of the new requirements did not have a material impact on Suncor's financial statements.

3. BUSINESS COMBINATION WITH PETRO-CANADA

(a) Overview

In the first quarter of 2009, Suncor announced that it had agreed to merge with Petro-Canada. The transaction was accomplished through a plan of arrangement, which included a share exchange, pursuant to which holders of common shares of Petro-Canada received 1.28 common shares of Suncor for each common share of Petro-Canada held.

In the second and third quarters of 2009, the arrangement received approval from Suncor and Petro-Canada shareholders, the Alberta Court of Queen's Bench, and the Competition Bureau of Canada. The transaction closed August 1, 2009 and the merged company continues to operate as Suncor Energy Inc.

(b) Accounting for Business Combinations

The company has accounted for this business combination as prescribed by CICA Handbook section 1581 "Business Combinations". As such, the company is required to recognize Petro-Canada assets and liabilities as at August 1, 2009. The results of Petro-Canada operations are included in the consolidated financial statements of the company from August 1, 2009.

(c) Consideration and Purchase Price

Consideration offered to complete the merger included 621.1 million shares of Suncor with a value of $18,878 million, or $30.39 per share, that were issued to Petro-Canada shareholders and 7.1 million Suncor share options with a fair value of $147 million, that were exchanged for existing Petro-Canada share options. The replacement of stock options and other stock-based compensation plans that are accounted for as liabilities are not included in consideration (see note 9).

The total purchase price for the acquisition was $19,630 million, consisting of the following amounts:

($ millions)	
621.1 million common shares issued to Petro-Canada shareholders	18,878
7.1 million Petro-Canada share options exchanged for share options of Suncor	147
Transaction costs	167
Effective settlement of pre-existing contract with Petro-Canada (note f)	438
Total purchase price	19,630

(d) Preliminary Allocation of Purchase Price

The following estimated fair values were assigned to the assets and liabilities of Petro-Canada as at August 1, 2009:

($ millions)	
Current assets	4,645
Property, plant and equipment	27,407
Other assets	537
Total assets	32,589
Current liabilities	3,741
Long-term debt	4,410
Accrued liabilities and other	3,416
Future income taxes	4,570
Total liabilities	16,137
Net assets purchased	16,452
Goodwill	3,178
Total purchase price	19,630

Cash acquired was $248 million, net of transaction costs of $167 million.

Other assets includes $236 million for intangible assets, relating to the Petro-Canada brand, with an indefinite life, and customer lists, which will be amortized over their estimated useful lives.

This preliminary allocation of the purchase price is based on current best estimates by Suncor's management and is based principally on valuations prepared by independent valuation specialists. The completion of the purchase price allocation may result in further adjustment to the carrying value of Petro-Canada's recorded assets and liabilities and the residual amount allocated to goodwill. $3,019 million of the goodwill has been allocated to the Oil Sands segment and the remaining $159 million has been allocated to the Refining and Marketing segment. No amount that is part of goodwill is expected to be deductible for tax purposes.

(e) Employee Future Benefits

The fair values assigned to the pension and post-retirement benefits plans assumed, included in accrued liabilities and other, are as follows:

($ millions)	Pension Benefits	Other Post-Retirement Benefits	Total
Market value of plan assets	1 255	—	1 255
Accrued benefit obligation	1 912	265	2 177
Net liability assumed	(657)	(265)	(922)

The valuation of the net liability assumed was based on the following assumptions:

(percent)	Pension Benefits	Other Post-Retirement Benefits
Discount rate	5.25	5.25
Rate of compensation increase	3.00	3.00
Expected return on plan assets	6.75	N/A

(f) Pre-Existing Contract with Petro-Canada

CICA Emerging Issues Committee Abstract 154 *Accounting for Pre-existing Relationships between the Parties of a Business Combination* states that the consummation of a business combination between parties with a pre-existing relationship requires an evaluation to determine if a settlement of the related contract exists, and where the relationship is favourable to the acquirer, that the purchase cost of the acquisition be the sum of the consideration paid and the benefit from the settlement of the relationship. The benefit is measured as the lesser of the amount of any stated settlement provisions in the contract and the amount by which the contract is favourable, from the perspective of the acquirer, when compared to pricing for current market transactions for the same or similar items.

In 2003, Suncor entered into a fee-for-service contract where it agreed to upgrade bitumen supplied by Petro-Canada. The contract came into effect January 1, 2009. The contract processing fee included an escalation factor tied to the price of West Texas Intermediate (WTI) crude, which was intended to approximate changes in Canadian light/heavy differentials for crude oil. The contract terms included a take-or-pay volume commitment and no early settlement provisions.

Since 2003, crude prices have increased significantly and industry conditions for the supply and demand of upgraded bitumen have changed dramatically resulting in the contract being favourable to Suncor at the transaction closing date. A value of $438 million was assigned to the effective settlement of the contract, by comparing estimated future processing fees on the take-or-pay volume commitment to estimated Canadian light/heavy differentials using future pricing assumptions for WTI, synthetic crude and bitumen.

The deemed settlement amount of $438 million (net of income taxes of $nil) is included in the total purchase price of the acquisition and included in interest and other income in the Consolidated Statement of Earnings.

4. CHANGE IN SEGMENTED DISCLOSURES

As a result of the business combination described in note 3, the company has reclassified its operations into the following segments.

Oil Sands includes the company's operations in northeast Alberta to produce synthetic crude through the recovery and upgrading of bitumen from mining and in-situ development.

Natural Gas includes exploration and production of natural gas, crude oil and natural gas liquids in western Canada and the U.S. Rockies.

The East Coast Canada segment comprises activity offshore Newfoundland and Labrador, and includes interests in the Hibernia, Terra Nova, White Rose and Hebron oilfields.

The International segment includes the exploration for, and production of, crude oil and natural gas in the United Kingdom, the Netherlands, Trinidad and Tobago, Libya and Syria.

Refining and Marketing includes the purchase and sale of crude oil, the refining of crude oil products, and the distribution and marketing of these and other purchased products through refineries located in eastern and western Canada and the U.S., as well as a lubricants plant located in eastern Canada. Energy trading activities that were previously included in the Refining and Marketing segment are now included within Corporate, Energy Trading and Eliminations. Prior period amounts have been restated to reflect this change in presentation.

The Corporate, Energy Trading and Eliminations includes third-party energy trading activities and activities not directly attributable to an operating segment.

All prior periods have been restated to conform to these segment definitions.

5. FINANCIAL INSTRUMENTS AND FINANCIAL RISK FACTORS

The recent merger has provided Suncor with the ability to capitalize on future trading opportunities due to increased transactional and trading capacity. As a result, we performed a review of our energy trading activities, and determined that certain physical trading commodity contracts have grown beyond their original intent and are no longer being used for the company's expected purchase, sale or usage requirements. Effective October 1, 2009, these contracts are now considered derivative financial instruments whereby realized and unrealized gains and losses, and the underlying settlement of these contracts is recognized and reported on a net basis in Energy Trading Activities revenue. The related inventory is carried at fair value less costs to sell, with changes in fair value recognized as gains or losses within Energy Trading Activities revenue.

(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 income tax, asset retirement and pension obligations), long-term debt, and a portion of non-current accrued liabilities and other. 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 December 31, 2009, the carrying value of our fixed-term debt accounted for under the amortized cost method was $10.1 billion (December 31, 2008 – $6.7 billion) and the fair value was $10.7 billion (December 31, 2008 – $5.4 billion).

(b) Hedges – Documented as Part of a Qualifying Hedge Relationship

Fair Value Hedges

At December 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 and twelve month periods ended December 31, 2009 and December 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 December 31, 2009 was a loss of $2 million, net of income taxes of nil (2008 – nil). During the twelve month period ended December 31, 2009, there was no earnings impact (2008 – loss of $4 million, net of income taxes of $2 million).

Cash Flow Hedges

Up to October 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 and twelve month periods ended December 31, 2009 and December 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)	**December 31 2009**	December 31 2008
Revenue hedge swaps and collars	**—**	(2)
Fixed to floating interest rate swaps	**17**	24
Specific hedges of individual transactions	**—**	(11)
Fair value of outstanding hedging derivative financial instruments	**17**	11

Accumulated Other Comprehensive Income (AOCI)

A reconciliation of changes in AOCI attributable to derivative hedging activities for the twelve-month periods ending December 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 – $3)	**2**	7
AOCI attributable to derivative hedging activities, at December 31, net of income taxes of $5 (2008 – $5)	**15**	13

(c) Derivatives

Commodity Price Risk Derivatives

The company periodically enters into derivative contracts for the purpose of managing price risk exposure associated with the sale and purchase of commodities. While these contracts are not accounted for as hedges because they have not been documented as such or do not qualify under GAAP, the company believes such contracts to be economically effective at mitigating its risk to adverse commodity price movements and is an important component of our overall risk management program. These contracts are accounted for using the mark-to-market method and, as such, they are recorded at fair value at each balance sheet date. The earnings impact associated with these contracts for the three months period ended December 31, 2009, was a loss of $100 million, net of income taxes of $34 million (2008 – a gain of $354 million, net of income taxes of $144 million). During the twelve month period ended December 31, 2009, the earnings impact was a loss of $763 million, net of income taxes of $261 million (2008 – a gain of $348 million, net of income taxes of $142 million).

Significant contracts outstanding at December 31, 2009 were as follows:

Crude oil	Quantity (bpd)	Average Price [1] (US$/bbl)	Period
Purchased puts [2]	55 000	60.00	2010
Sold puts [3]	54 753	60.00	2010
Collars – floor	50 041	50.00	2010
Collars – cap	49 986	68.06	2010

(1) Average price for crude puts is US$ WTI per barrel at Cushing, Oklahoma.

(2) Total premium paid was US$29.5 million.

(3) Premium received was US$213 million.

Energy Trading Derivatives

The company's Energy Trading division also uses physical and financial energy contracts, including swaps, forwards and options to earn trading and marketing revenues. These energy contracts are comprised of crude oil, natural gas and refined products contracts. Financial and physical energy trading activities are accounted for using the mark-to-market method, the associated gains and losses and the underlying settlement of these contracts is recognized and reported on a net basis in Energy Trading Activities Revenue in the Consolidated Statements of Earnings and Comprehensive Income.

The earnings impact associated with these contracts for the three months period ended December 31, 2009, was a loss of $13 million, net of income taxes of $4 million (2008 – a gain of $88 million, net of income taxes of $36 million). During the twelve month period ended December 31, 2009, the earnings impact was a loss of $52 million, net of income taxes of $18 million (2008 – a gain of $90 million, net of income taxes of $37 million).

Fair Value of Non-Designated Derivative Financial Instruments

The fair values of unsettled (unrealized) energy derivative assets and liabilities above are as follows:

($ millions)	**December 31 2009**	December 31 2008
Derivative assets[(a)]	**213**	635
Derivative liabilities[(b)]	**572**	14
Net derivative assets (liabilities)	**(359)**	621

(a) As at December 31, 2009, $213 million is recorded in accounts receivable (2008 – $376 million recorded in accounts receivable and $259 million recorded in other assets) in the Consolidated Balance Sheets.

(b) As at December 31, 2009, $572 million is recorded in accounts payable and accrued liabilities (2008 – $14 million).

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	**448**
Fair value of contracts entered into during the period	**(983)**
Changes in fair value during the period	**(445)**
Fair value of contracts outstanding at December 31, 2009	**(359)**

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 December 31, 2009, the company's exposure to risks associated arising from the use of financial instruments had not changed significantly from December 31, 2008.

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 December 31, 2009:

Financial Instrument Sensitivity Analysis on Derivative Contracts

($ millions)	December 31, 2009 [1]	Change	Net Earnings	Other Comprehensive Income
Crude Oil	US$85.55/barrel			
Price increase		US$1.00/barrel	(18)	—
Price decrease		US$1.00/barrel	18	—
Natural Gas	US$5.81/mcf			
Price increase		US$0.10/mcf	(1)	—
Price decrease		US$0.10/mcf	1	—

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

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

6. 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 [1] and total debt to total debt plus shareholders' equity.

Net debt to cash flow from operations is calculated as short-term debt plus total 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 total long-term debt divided by short-term debt plus total long-term debt plus shareholders' equity.

The company's strategy during the fourth quarter of 2009 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 December 31, ($ millions)	Capital Measure Target	**2009**	2008
Components of ratios			
Short-term debt		**2**	2
Current portion of long-term debt		**25**	18
Long-term debt		**13 855**	7 866
Total debt		**13 882**	7 886
Cash and equivalents		**505**	660
Net debt		**13 377**	7 226
Shareholders' equity		**34 111**	14 523
Total capitalization (total debt + shareholders' equity)		**47 993**	22 409
Cash flow from operations [1] (trailing twelve months)		**2 799**	4 057
Net debt/cash flow from operations	< 2.0 times	**4.8**	1.8
Total debt/total debt plus shareholders' equity		**29%**	35%

(1) Cash flow from operations is expressed before changes in non-cash working capital. Cash flow from operations is the same measure as the cash flow from operating activities before changes in working capital measure that is included in the unaudited interim consolidated financial statements.

The increase in debt levels as a result of the merger with Petro-Canada has caused our net debt/cash flow from operations measure to increase significantly, as the calculation only includes five months of cash flow from operations relating to legacy Petro-Canada operations.

The company's capital management strategy, objectives, definitions, monitoring measures and targets have not changed significantly from the prior period.

7. FINANCING EXPENSES (INCOME)

	Three months ended December 31		Twelve months ended December 31	
($ millions)	**2009**	2008	**2009**	2008
Interest on debt	**182**	110	**573**	352
Capitalized interest	**(42)**	(110)	**(136)**	(352)
Net interest expense	**140**	—	**437**	—
Foreign exchange (gain) loss on long-term debt	**(201)**	681	**(858)**	919
Other foreign exchange (gain) loss	**(9)**	(5)	**(66)**	(2)
Total financing expenses (income)	**(70)**	676	**(487)**	917

8. RECONCILIATION OF BASIC AND DILUTED EARNINGS PER COMMON SHARE

	Three months ended December 31		Twelve months ended December 31	
($ millions)	**2009**	2008	**2009**	2008
Net earnings	**457**	(215)	**1 146**	2 137
(millions of common shares)				
Weighted-average number of common shares	**1 560**	935	**1 198**	932
Dilutive securities:				
Options issued under stock-based compensation plans	**14**	8	**13**	13
Weighted-average number of diluted common shares	**1 574**	943	**1 211**	945
(dollars per common share)				
Basic earnings per share [(a)]	**0.29**	(0.24)	**0.96**	2.29
Diluted earnings per share [(b)]	**0.29**	(0.24)	**0.95**	2.26

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.

9. SHARE CAPITAL

Issued

	Common Shares	
	Number (thousands)	Amount ($ millions)
Balance as at December 31, 2008	935 524	1 113
Shares issued to Petro-Canada shareholders (note 3)	**621 142**	**18 878**
Issued for cash under stock option plans	**2 968**	**57**
Issued under dividend reinvestment plan	**144**	**5**
Balance as at December 31, 2009	**1 559 778**	**20 053**

Stock-Based Compensation

A stock 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. The holder must fulfill a time requirement for service to the company, at which time the option is considered vested. Certain options are subject to accelerated vesting should the company meet predetermined performance criteria.

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.

Certain stock options with a cash payment alternative (CPA) entitle the holder to surrender vested options for cancellation in return for a direct cash payment based on the excess of the then current market price of the underlying common share over the option exercise price or for a common share in the company at the option exercise price.

A stock appreciation right unit (SAR) entitles the holder to receive a cash payment equal to the difference between the stated exercise price and the market price of the company's common shares on the date the vested option is surrendered.

A performance share unit (PSU) is a time-vested 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 (RSU) is a time-vested award entitling employees to receive cash.

A deferred share unit (DSU) is a notional share unit, redeemable for cash or a common share for a period of time after a unitholder ceases employment or Board membership. The DSU plan is only for executives and members of the company's Board of Directors.

(a) Stock Option Plans:

(i) SunShare 2012 Performance Stock Options

Granting of options under this plan ended on July 31, 2009. A total of 1,204,000 options were granted in the twelve months ended December 31, 2009 (851,000 options granted during the fourth quarter of 2008; 2,637,000 options granted during the twelve months ended December 31, 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 which have not previously expired or been cancelled will automatically expire on January 1, 2013.

(ii) Executive Stock Options

Granting of options under this plan ended on July 31, 2009. A total of 711,000 options were granted in the twelve months ended December 31, 2009 (25,000 options granted during the fourth quarter of 2008; 895,000 granted in the twelve months ended December 31, 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 Options

Granting of options under this plan ended on July 31, 2009. A total of 571,000 options were granted in the twelve months ended December 31, 2009 (2,000 options granted during the fourth quarter of 2008; 2,375,000 granted in the twelve months ended December 31, 2008) to non-insider senior managers and key employees. Options granted have a ten-year life and vest annually over a three-year period.

(iv) Petro-Canada Stock Options ("Adjusted Options")

Granting of options under this plan ended on July 31, 2009. In conjunction with the business combination transaction described in note 3, each outstanding option issued under the Petro-Canada Stock Option Plan to purchase Petro-Canada common shares was exchanged on August 1, 2009 for 1.28 options to purchase Suncor common shares, for a total of

29.9 million options outstanding at August 1, 2009. The same exchange ratio was applied to the exercise price of these options.

The Adjusted Options, issued to officers and certain employees, have a term of ten years if granted prior to 2004 and seven years if granted subsequent to 2003. Holders of options granted after 2003 are entitled to exercise the options in exchange for a cash payment alternative (CPA). A total of 22.8 million of the Adjusted Options outstanding on August 1, 2009 had a CPA and are recorded in accrued liabilities and other on the Consolidated Balance Sheets, based on their intrinsic value at each period end. All Adjusted Options vest over periods of up to four years.

As at December 31, 2009, there were 27.9 million Adjusted Options outstanding with a weighted-average exercise price per share of $28.05.

(v) Suncor Energy Inc. Stock Options

The company did not grant options under this plan in the fourth quarter of 2009. A total of 4,000 options were granted in 2009. This plan came into effect on August 1, 2009 and replaces the pre-merger stock option plans of legacy Petro-Canada and Suncor. Outstanding Adjusted Options that are cancelled, expire or are terminated or otherwise result in no underlying common share being issued will be available for issuance as options under this plan.

Stock Options Outstanding and Exercisable

The following table summarizes outstanding and exercisable common share options as at December 31, 2009:

	Outstanding			Exercisable	
Exercise Prices ($)	Number (thousands)	Weighted-Average Remaining Contractual Life (years)	Weighted-Average Exercise Price Per Share ($)	Number (thousands)	Weighted-Average Exercise Price Per Share ($)
7.84 – 12.99	2 476	1	10.03	2 476	10.03
13.00 – 17.99	13 984	2	14.18	13 984	14.18
18.00 – 29.99	15 157	4	22.31	10 788	22.93
30.00 – 44.99	17 736	4	38.91	10 863	39.72
45.00 – 49.99	21 216	5	47.45	4 557	46.51
50.00 – 72.68	1 455	5	57.62	87	52.75
Total	72 024	4	32.52	42 755	26.16

Fair Value of Options Granted

The fair values of all legacy Suncor common share options granted during the period and Adjusted Options granted in 2003 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. Adjusted Options which have a CPA granted subsequent to 2003 are accounted for based on the intrinsic value at each period end. 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 December 31		Twelve months ended December 31	
	2009	2008	**2009**	2008
Quarterly dividend per share*	**—**	$0.05	**$0.08**	$0.05
Risk-free interest rate	**—**	2.81%	**2.31%**	3.35%
Expected life	**—**	5 years	**5 years**	6 years
Expected volatility	**—**	36%	**47%**	30%
Weighted-average fair value per option	**—**	$8.81	**$10.28**	$13.86

* In 2009, quarterly dividends of $0.05 per share were paid in the first and second quarter, and $0.10 per share in the third and fourth quarter.

(b) Petro-Canada Stock Appreciation Rights ("Adjusted SARs")

In conjunction with the business combination described in note 3, each outstanding SAR issued under the Petro-Canada Stock Option Plan was exchanged with 1.28 SARs resulting in the addition of 15,353,000 SARs at August 1, 2009.

The following table summarizes outstanding and exercisable Adjusted SARs as at December 31, 2009:

	Outstanding			Exercisable	
Exercise Prices ($)	Number (thousands)	Weighted-Average Remaining Contractual Life (years)	Weighted-Average Exercise Price Per Share ($)	Number (thousands)	Weighted-Average Exercise Price Per Share ($)
19.13 – 25.00	6 177	6	19.45	7	20.81
25.01 – 35.00	3 538	4	34.31	1 637	34.33
35.01 – 40.00	4 212	5	36.84	1 040	36.87
40.01 – 46.13	138	5	43.83	56	43.65
Total	14 065	5	28.63	2 740	35.45

(c) Performance Share Units (PSUs)

The company did not issue any PSUs in the fourth quarter of 2009 (2008 – 13,000). For the twelve months ended December 31, 2009, the company issued 1,149,000 PSUs (2008 – 795,000). In conjunction with the business combination described in note 3, each outstanding Petro-Canada PSU was adjusted by 1.28, resulting in the addition of 945,000 PSUs at August 1, 2009.

(d) Restricted Share Units (RSUs)

In the fourth quarter of 2009, the company issued 66,000 RSUs (2008 – 53,000). For the twelve months ended December 31, 2009, the company issued 2,715,000 RSUs (2008 – 1,078,000). In conjunction with the business combination described in note 3, each outstanding Petro-Canada RSU was adjusted by 1.28, resulting in the addition of 1,018,000 RSUs at August 1, 2009.

(e) Deferred Share Units (DSUs)

In the fourth quarter of 2009, the company issued 18,000 DSUs (2008 – nil). For the twelve months ended December 31, 2009, the company issued 48,000 DSUs (2008 – 30,000). In conjunction with the business combination described in note 3, each outstanding Petro-Canada PSU was adjusted by 1.28, resulting in the addition of 1,008,000 DSUs at August 1, 2009.

Stock-Based Compensation Expense (Recovery)

The following table summarizes the stock based compensation expense (recovery) recorded for all plans within operating, selling and general expense on the Consolidated Statements of Earnings:

	Three months ended December 31		Twelve months ended December 31	
($ millions)	**2009**	2008	**2009**	2008
Stock option plans	**32**	26	**148**	120
Adjusted SARs	**10**	—	**35**	—
Performance share units (PSUs)	**11**	(27)	**30**	(30)
Restricted share units (RSUs)	**(7)**	(2)	**50**	8
Deferred share units (DSUs)	**—**	(38)	**30**	(51)
Total stock based compensation expense (recovery)	**46**	(41)	**293**	47

10. EMPLOYEE FUTURE BENEFITS LIABILITY

The following is the status of the net periodic benefit cost for the three and twelve months ended December 31:

			Pension Benefits	
	Three months ended December 31		Twelve months ended December 31	
($ millions)	**2009**	2008	**2009**	2008
Current service costs	**18**	14	**67**	56
Interest costs	**39**	13	**96**	49
Expected return on plan assets	**(32)**	(12)	**(76)**	(45)
Amortization of net actuarial loss	**6**	5	**21**	22
Net periodic benefit cost	**31**	20	**108**	82

			Other Post-Retirement Benefits	
	Three months ended December 31		Twelve months ended December 31	
($ millions)	**2009**	2008	**2009**	2008
Current service costs	**2**	1	**7**	4
Interest costs	**6**	2	**15**	9
Amortization of net actuarial loss	**—**	1	**—**	3
Net periodic benefit cost	**8**	4	**22**	16

11. SUPPLEMENTAL INFORMATION

	Three months ended December 31		Twelve months ended December 31	
($ millions)	**2009**	2008	**2009**	2008
Interest paid	**284**	150	**581**	328
Income taxes paid	**196**	131	**872**	638

12. LONG-TERM DEBT AND CREDIT FACILITIES

($ millions)	**December 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)	**785**	918
6.80% Notes, denominated in U.S. dollars, due in 2038 (US$900)	**972**	—
6.50% Notes, denominated in U.S. dollars, due in 2038 (US$1150)	**1 204**	1 408
5.95% Notes, denominated in U.S. dollars, due in 2035 (US$600)	**578**	—
5.95% Notes, denominated in U.S. dollars, due in 2034 (US$500)	**523**	612
5.35% Notes, denominated in U.S. dollars, due in 2033 (US$300)	**266**	—
7.15% Notes, denominated in U.S. dollars, due in 2032 (US$500)	**523**	612
6.10% Notes, denominated in U.S. dollars, due in 2018 (US$1250)	**1 308**	1 531
6.05% Notes, denominated in U.S. dollars, due in 2018 (US$600)	**643**	—
5.00% Notes, denominated in U.S. dollars, due in 2014 (US$400)	**429**	—
4.00% Notes, denominated in U.S. dollars, due in 2013 (US$300)	**313**	—
7.00% Debentures, denominated in U.S. dollars, due in 2028 (US$250)	**271**	—
7.875% Debentures, denominated in U.S. dollars, due in 2026 (US$275)	**325**	—
9.25% Debentures, denominated in U.S. dollars, due in 2021 (US$300)	**402**	—
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
	10 342	6 881
Revolving-term debt, with interest at variable rates		
Commercial paper, bankers' acceptances and LIBOR loans	**3 244**	934
Total unsecured long-term debt	**13 586**	7 815
Secured long-term debt	**13**	13
Capital leases	**326**	103
Fair value of interest swaps	**18**	25
Deferred financing costs	**(63)**	(72)
	13 880	7 884
Current portion of long-term debt		
Capital leases	**(14)**	(9)
Fair value of interest swaps	**(11)**	(9)
Total current portion of long-term debt	**(25)**	(18)
Total long-term debt	**13 855**	7 866

Certain of the notes and debentures of the company were acquired in the business combination described in note 3 and were accounted for at their fair value at the date of acquisition. The difference between the fair value and the principal amount of these debts of $121 million is being amortized over the remaining life of the debt acquired.

At December 31, 2009, undrawn lines of credit were $4,208 million, as follows:

($ millions)	**2009**
Facility that is fully revolving for 364 days, has a term period of one year and expires in 2010	**61**
Facility that is fully revolving for a period of four years and expires in 2013	**209**
Facility that is fully revolving for a period of five years and expires in 2013	**7 320**
Facilities that can be terminated at any time at the option of the lenders	**598**
Total available credit facilities	**8 188**
Credit facilities supporting outstanding commercial paper, bankers' acceptances and LIBOR loans	**3 244**
Credit facilities supporting standby letters of credit	**736**
Total undrawn credit facilities	**4 208**

13. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

($ millions)	**December 31 2009**	December 31 2008
Unrealized foreign currency translation gain (loss)	**(248)**	84
Unrealized gains on derivative hedging activities	**15**	13
Total	**(233)**	97

14. INCOME TAXES

	Three months ended December 31		Twelve months ended December 31	
($ millions)	**2009**	2008	**2009**	2008
Provision for (recovery of) income taxes:				
Current:				
Canada	**28**	113	**599**	520
Foreign	**187**	(5)	**269**	(6)
Future:				
Canada	**(137)**	(23)	**(702)**	515
Foreign	**(50)**	(61)	**(23)**	(34)
Total provision for income taxes	**28**	24	**143**	995

In the fourth quarter of 2009, the Ontario provincial government substantively enacted a 4% reduction to its provincial corporate tax rates. Accordingly, the company recognized a reduction in future income tax expense of $148 million related to the revaluation of its opening future income tax balances, allocated to the segments as follows: Oil Sands – $103 million, Natural Gas – $8 million, East Coast Canada – $20 million, Refining and Marketing – $19 million, Corporate, Energy Trading and Eliminations – ($2) million.

15. CHANGES IN NON-CASH WORKING CAPITAL

Non-cash working capital is comprised of current assets and current liabilities, other than cash and cash equivalents, future income taxes and the current portion of long-term debt.

The (increase) decrease in non-cash working capital is comprised of:

	Three months ended December 31		Twelve months ended December 31	
($ millions)	**2009[1]**	2008	**2009[1]**	2008
Operating activities				
Accounts receivable	**55**	474	**123**	226
Inventories	**(209)**	440	**(585)**	103
Accounts payable and accrued liabilities	**503**	59	**282**	186
Taxes payable/receivable	**(5)**	15	**(44)**	(110)
	344	988	**(224)**	405

(1) Balances do not include amounts acquired from Petro-Canada as a result of the merger, but do reflect the changes in these working capital accounts subsequent to August 1, 2009.

16. DIVESTITURES

Natural Gas

On December 31, 2009, Suncor entered into an agreement to sell substantially all of its oil and gas producing assets in the United States Rockies for proceeds of $517 million (US$494 million) which is approximately equal to its net book value as at December 31, 2009. The sale is expected to close in March 2010.

Refining and Marketing

In conjunction with the merger with Petro-Canada, the Competition Bureau of Canada required Suncor to divest 104 retail sites in Ontario. On December 8, 2009, Suncor agreed to sell 98 sites with expected closing dates commencing in the first half of 2010 as ownership of individual sites is transferred to the purchaser.

Highlights

(unaudited)

	2009	2008
Cash Flow From Operations		
(dollars per common share – basic)		
For the three months ended December 31		
Cash flow from operations[1]	**0.72**	0.25
For the twelve months ended December 31		
Cash flow from operations[1]	**2.34**	4.36
Ratios		
For the twelve months ended December 31		
Return on capital employed (%)[2]	**2.6**	22.5
Return on capital employed (%)[3]	**1.8**	16.3
Net debt to cash flow from operations (times)[4]	**4.8**	1.8
Pro forma – Net debt to cash flow from operations (times)[5]	**3.2**	N/A
Interest coverage on long-term debt (times)		
Net earnings[6]	**3.0**	8.9
Cash flow from operations[7]	**7.2**	13.0
As at December 31		
Debt to debt plus shareholders' equity (%)[8]	**28.9**	35.2
Common Share Information		
As at December 31		
Share price at end of trading		
Toronto Stock Exchange – Cdn$	**37.21**	23.72
New York Stock Exchange – US$	**35.31**	19.50
Common share options outstanding (thousands)	**72 024**	46 402
For the twelve months ended December 31		
Average number outstanding, weighted monthly (thousands)	**1 197 710**	931 524

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 – $637 million; 2008 – $2,989 million) after adjustment to add back after-tax financing income (2009 – $509 million; 2008 – expense of $852 million) divided by average capital employed (2009 – $24,473 million; 2008 – $13,298 million). Average capital employed is shareholders' equity and short-term debt plus long-term debt less cash and cash equivalents, less capitalized costs related to major projects in progress (as applicable), on a weighted-average basis. 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.

(3) If capital employed were to include capitalized costs related to major projects in progress (average capital employed including major projects in progress: 2009 – $35,128 million; 2008 – $18,447 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. The increase in debt levels as a result of the merger with Petro-Canada has caused our net debt/cash flow from operations measure to increase significantly, as the calculation only includes five months of cash flow from operations relating to legacy Petro-Canada operations.

(5) Pro forma net debt to cash flow from operations is calculated by taking short-term debt plus long-term debt less cash and cash equivalents, divided by the sum of cash flow from operations for the twelve-month period ended December 31, 2009, plus cash flow from operations for legacy Petro-Canada operations for the seven-month period ended July 31, 2009. Cash flow from operations for legacy Petro-Canada operations over this seven-month period totalled $1,438 million.

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

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

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

Quarterly Operating Summary

(unaudited)

	Three months ended					Twelve months ended	
	Dec 31	Sept 30	June 30	Mar 31	Dec 31	**Dec 31**	Dec 31
	2009	2009	2009	2009	2008	**2009**	2008
OIL SANDS							
Production [1],[a]							
Total production (excluding Syncrude)	**278.9**	305.3	301.0	278.0	243.8	**290.6**	228.0
Firebag [k]	**51.1**	54.3	48.3	42.4	39.7	**49.1**	37.4
MacKay River [k]	**31.7**	26.5***	—	—	—	**29.7*** **	—
Syncrude	**39.3**	37.4***	—	—	—	**38.5*** **	—
Sales [a] (excluding Syncrude)							
Light sweet crude oil	**100.8**	89.6	99.4	108.8	95.7	**99.6**	77.0
Diesel	**31.4**	36.9	25.3	22.8	19.1	**29.1**	19.8
Light sour crude oil	**142.4**	146.8	150.5	102.7	144.2	**135.7**	128.7
Bitumen	**13.0**	14.3	10.5	9.1	3.1	**11.8**	1.5
Total sales	**287.6**	287.6	285.7	243.4	262.1	**276.2**	227.0
Average sales price [2],[b] (excluding Syncrude)							
Light sweet crude oil*	**77.71**	71.99	65.83	54.64	63.69	**67.26**	98.66
Other (diesel, light sour crude oil and bitumen) *	**72.93**	67.51	62.71	48.80	59.77	**64.18**	95.14
Total *	**74.61**	68.91	63.79	52.78	61.20	**65.29**	96.33
Total	**64.81**	61.70	59.00	59.14	61.53	**61.26**	95.96
Syncrude average sales price [2],[b]	**78.81**	75.17	—	—	—	**77.36**	—
Cash operating costs and Total operating costs – Total operations (excluding Syncrude) [c]							
Cash costs	**35.10**	30.65	29.65	30.65	35.35	**31.50**	31.45
Natural gas	**3.40**	1.55	1.65	3.00	4.05	**2.40**	5.25
Imported bitumen	**0.20**	0.05	—	0.05	1.90	**0.05**	1.80
Cash operating costs [3]	**38.70**	32.25	31.30	33.70	41.30	**33.95**	38.50
Project start-up costs	**0.50**	0.45	0.35	0.65	0.30	**0.45**	0.40
Total cash operating costs [4]	**39.20**	32.70	31.65	34.35	41.60	**34.40**	38.90
Depreciation, depletion and amortization	**10.00**	7.60	7.20	7.30	7.50	**8.00**	6.95
Total operating costs [5]	**49.20**	40.30	38.85	41.65	49.10	**42.40**	45.85
Cash operating costs and Total operating costs – Syncrude [c]****							
Cash costs	**29.65**	29.50	—	—	—	**29.60**	—
Natural gas	**3.45**	2.10	—	—	—	**2.90**	—
Cash operating costs [3]	**33.10**	31.60	—	—	—	**32.50**	—
Project start-up costs	**—**	—	—	—	—	**—**	—
Total cash operating costs [4]	**33.10**	31.60	—	—	—	**32.50**	—
Depreciation, depletion and amortization	**11.80**	12.70	—	—	—	**12.15**	—
Total operating costs [5]	**44.90**	44.30	—	—	—	**44.65**	—
Cash operating costs and Total operating costs – In-situ bitumen production only [c]							
Cash costs	**11.35**	10.25	11.15	10.50	16.55	**10.90**	13.00
Natural gas	**6.05**	4.30	5.25	7.90	9.65	**5.70**	12.30
Cash operating costs [6]	**17.40**	14.55	16.40	18.40	26.20	**16.60**	25.30
In-situ start-up costs	**1.25**	0.65	1.50	3.35	—	**1.30**	0.65
Total cash operating costs [7]	**18.65**	15.20	17.90	21.75	26.20	**17.90**	25.95
Depreciation, depletion and amortization	**6.65**	5.95	6.00	7.10	6.55	**6.35**	6.35
Total operating costs [8]	**25.30**	21.15	23.90	28.85	32.75	**24.25**	32.30
Ending capital employed excluding major projects in progress [i]	**16 141**	14 833	10 008	10 610	9 352		
(for the twelve months ended)							
Return on capital employed [j]	**4.2**	8.4	11.1	22.9	35.5		
Return on capital employed [j]**	**2.5**	4.9	6.5	13.9	21.8		

Footnotes and definitions, see page 42

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Five months ended	Twelve months ended	
	Dec 31 2009	Sept 30 2009	June 30 2009	Mar 31 2009	Dec 31 2008	**Dec 31 2009**	**Dec 31 2009**	Dec 31 2008
NATURAL GAS								
Gross production								
Natural gas[d]								
Western Canada	**620**	477	192	200	195	**621**	**374**	202
U.S. Rockies	**54**	40	—	—	—	**56**	**24**	—
Natural gas liquids and crude oil[a]								
Western Canada	**10.8**	8.3	3.2	3.1	3.1	**11.0**	**6.4**	3.1
U.S. Rockies	**4.2**	2.4	—	—	—	**4.0**	**1.7**	—
Total gross production[f]								
Western Canada	**685**	527	211	219	213	**687**	**412**	220
U.S. Rockies	**79**	54	—	—	—	**80**	**34**	—
Average sales price[2]								
Natural gas[g]								
Western Canada	**4.46**	2.88	3.56	5.63	6.90	**3.94**	**4.11**	8.23
U.S. Rockies	**4.62**	3.01	—	—	—	**3.93**	**3.93**	—
Natural gas[g]*								
Western Canada	**4.45**	2.86	3.52	5.61	6.84	**3.93**	**4.09**	8.25
U.S. Rockies	**4.62**	3.01	—	—	—	**3.93**	**3.93**	—
Natural gas liquids and crude oil[b]								
Western Canada	**60.06**	53.28	41.39	39.03	39.31	**57.67**	**52.97**	70.89
U.S. Rockies	**74.19**	67.08	—	—	—	**71.62**	**71.62**	—
Ending capital employed[i]	**3 349**	3 632	1 200	1 195	1 152			
(for the twelve months ended)								
Return on capital employed[j]	**(8.4)**	(9.6)	(1.7)	5.0	7.7			

Footnotes and definitions, see page 42

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Twelve months ended	
	Dec 31 2009	Sept 30 2009***	June 30 2009	Mar 31 2009	Dec 31 2008	**Dec 31 2009*****	Dec 31 2008
EAST COAST CANADA							
Production[a]							
Terra Nova	**24.0**	16.0	—	—	—	**20.8**	—
Hibernia	**26.3**	28.5	—	—	—	**27.2**	—
White Rose	**13.3**	5.1	—	—	—	**10.0**	—
Total production	**63.6**	49.6	—	—	—	**58.0**	—
Average sales price[2]	**77.71**	75.22	—	—	—	**76.86**	—
Ending capital employed excluding major projects in progress[i]	**2 142**	2 050	—	—	—		
(for the twelve months ended)							
Return on capital employed[j]	**10.7**	12.2	—	—	—		
Return on capital employed[j]**	**6.5**	7.4	—	—	—		
INTERNATIONAL							
Production[e]							
North Sea							
Buzzard	**59.9**	29.4	—	—	—	**47.8**	—
Other U.K.	**18.2**	11.4	—	—	—	**15.5**	—
The Netherlands sector of the North Sea	**12.9**	13.8	—	—	—	**13.2**	—
Total North Sea	**91.0**	54.6	—	—	—	**76.5**	—
Other International							
Libya	**26.0**	42.7	—	—	—	**32.6**	—
Trinidad & Tobago	**12.0**	11.3	—	—	—	**11.7**	—
Total Other International	**38.0**	54.0	—	—	—	**44.3**	—
Total production	**129.0**	108.6	—	—	—	**120.8**	—
Average sales price[2] **– North Sea**[l]	**71.46**	68.67	—	—	—	**71.63**	—
Average sales price[2] **– Other International**[l]	**59.04**	62.40	—	—	—	**61.25**	—
Ending capital employed excluding major projects in progress[i]	**2 828**	2 230	—	—	—		
(for the twelve months ended)							
Return on capital employed[j]	**11.5**	7.3	—	—	—		
Return on capital employed[j]**	**7.5**	4.8	—	—	—		

Footnotes and definitions, see page 42

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Five months ended	Twelve months ended	
	Dec 31 2009	Sept 30 2009	June 30 2009	Mar 31 2009	Dec 31 2008	**Dec 31 2009**	**Dec 31 2009**	Dec 31 2008
REFINING & MARKETING								
Eastern North America								
Refined product sales [h]								
Transportation fuels								
Gasoline – retail	**16.5**	12.5	4.0	3.8	3.9	**16.6**	**9.3**	3.9
– other	**6.5**	5.8	4.7	4.4	5.0	**6.4**	**5.3**	4.0
Distillate	**13.9**	10.3	5.4	5.1	5.4	**13.4**	**8.8**	5.2
Total transportation fuel sales	**36.9**	28.6	14.1	13.3	14.3	**36.4**	**23.4**	13.1
Petrochemicals	**1.2**	1.7	1.0	1.0	1.0	**1.7**	**0.8**	0.8
Asphalt	**2.0**	2.4	0.7	0.8	0.5	**2.5**	**1.5**	0.6
Other	**1.9**	3.0	1.0	0.5	0.5	**2.7**	**2.0**	1.0
Total refined product sales	**42.0**	35.7	16.8	15.6	16.3	**43.3**	**27.7**	15.5
Crude oil supply and refining								
Processed at refineries [h]	**28.3**	25.5	11.8	11.3	11.2	**29.9**	**29.6**	11.0
Utilization of refining capacity [j]	**83**	94	87	84	101	**88**	**87**	99
Western North America								
Refined product sales [h]								
Transportation fuels								
Gasoline – retail	**5.0**	3.8	0.6	0.7	0.7	**5.1**	**2.6**	0.7
– other	**13.4**	12.3	8.3	7.5	7.1	**13.8**	**10.4**	7.3
Distillate	**15.6**	11.8	5.0	5.4	5.5	**15.4**	**9.5**	5.6
Total transportation fuel sales	**34.0**	27.9	13.9	13.6	13.3	**34.3**	**22.5**	13.6
Asphalt	**0.9**	1.7	1.4	1.2	1.0	**1.2**	**1.3**	1.2
Other	**6.0**	4.6	1.8	1.0	0.9	**6.0**	**3.4**	1.2
Total refined product sales	**40.9**	34.2	17.1	15.8	15.2	**41.5**	**27.2**	16.0
Crude oil supply and refining								
Processed at refineries [h]	**33.4**	27.8	15.6	14.2	13.6	**33.6**	**33.6**	13.7
Utilization of refining capacity [j]	**96**	100	106	96	95	**97**	**97**	96
Ending capital employed excluding major projects in progress [i]	**8 304**	8 300	3 224	2 985	2 974			
(for the twelve months ended)								
Return on capital employed [j]	**7.5**	2.5	3.0	3.7	1.8			

Footnotes and definitions, see page 42

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Twelve months ended	
	Dec 31 2009	Sept 30 2009	June 30 2009	Mar 31 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
NETBACKS							
Natural Gas [g]							
Western Canada							
Average price realized [9]	**5.05**	3.76	3.88	5.77	6.99	**4.58**	9.35
Royalties	**(0.72)**	(0.24)	0.33	(1.14)	(1.60)	**(0.49)**	(2.17)
Operating costs	**(1.77)**	(1.90)	(1.71)	(1.65)	(1.46)	**(1.79)**	(1.60)
Operating netback	**2.56**	1.62	2.50	2.98	3.93	**2.30**	5.58
Depreciation, depletion and amortization	**(2.62)**	(2.73)	(2.92)	(2.97)	(2.98)	**(2.74)**	(2.89)
Administrative expenses and other	**(1.09)**	(1.60)	(1.63)	(0.78)	(1.23)	**(1.29)**	(1.23)
Earnings before income taxes	**(1.15)**	(2.71)	(2.05)	(0.77)	(0.28)	**(1.73)**	1.46
U.S. Rockies							
Average price realized [9]	**7.15**	5.20	—	—	—	**6.35**	—
Royalties	**(1.13)**	(0.82)	—	—	—	**(1.01)**	—
Operating costs	**(1.83)**	(1.79)	—	—	—	**(1.82)**	—
Operating netback	**4.19**	2.59	—	—	—	**3.52**	—
Depreciation, depletion and amortization	**(3.44)**	(3.20)	—	—	—	**(3.35)**	—
Administrative expenses and other	**(0.66)**	(0.47)	—	—	—	**(0.58)**	—
Earnings before income taxes	**0.09**	(1.08)	—	—	—	**(0.41)**	—
Total Natural Gas							
Average price realized [9]	**5.26**	3.89	3.88	5.77	6.99	**4.71**	9.35
Royalties	**(0.76)**	(0.29)	0.33	(1.14)	(1.60)	**(0.53)**	(2.17)
Operating costs	**(1.78)**	(1.89)	(1.71)	(1.65)	(1.46)	**(1.79)**	(1.60)
Operating netback	**2.72**	1.71	2.50	2.98	3.93	**2.39**	5.58
Depreciation, depletion and amortization	**(2.70)**	(2.78)	(2.92)	(2.97)	(2.98)	**(2.79)**	(2.89)
Administrative expenses and other	**(1.05)**	(1.49)	(1.63)	(0.78)	(1.23)	**(1.23)**	(1.23)
Earnings before income taxes	**(1.03)**	(2.56)	(2.05)	(0.77)	(0.28)	**(1.63)**	1.46
East Coast Canada [b]							
Average price realized [9]	**79.69**	77.85	—	—	—	**79.07**	—
Royalties	**(25.26)**	(21.02)	—	—	—	**(23.82)**	—
Operating costs	**(7.89)**	(13.36)	—	—	—	**(9.76)**	—
Operating netback	**46.54**	43.47	—	—	—	**45.49**	—
Depreciation, depletion and amortization	**(26.56)**	(17.48)	—	—	—	**(23.47)**	—
Administrative expenses and other	**(1.33)**	(0.52)	—	—	—	**(1.05)**	—
Earnings before income taxes	**18.65**	25.47	—	—	—	**20.97**	—

Footnotes and definitions, see page 42

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Twelve months ended	
	Dec 31 2009	Sept 30 2009	June 30 2009	Mar 31 2009	Dec 31 2008	**Dec 31 2009**	Dec 31 2008
International							
North Sea[b]							
Average price realized[9]	**71.46**	72.06	—	—	—	**71.63**	—
Operating costs	**(8.08)**	(14.04)	—	—	—	**(9.78)**	—
Operating netback	**63.38**	58.02	—	—	—	**61.85**	—
Depreciation, depletion and amortization	**(34.63)**	(24.54)	—	—	—	**(31.76)**	—
Administrative expenses and other	**(4.62)**	(7.61)	—	—	—	**(5.48)**	—
Earnings before income taxes	**24.13**	25.87	—	—	—	**24.61**	—
Other International							
North Africa/Near East[b]							
Average price realized[9]	**79.97**	76.02	—	—	—	**78.19**	—
Royalties	**(32.12)**	(46.46)	—	—	—	**(39.88)**	—
Operating costs	**(6.03)**	(2.21)	—	—	—	**(4.05)**	—
Operating netback	**41.82**	27.35	—	—	—	**34.26**	—
Depreciation, depletion and amortization	**(7.70)**	(2.31)	—	—	—	**(4.89)**	—
Administrative expenses and other	**(10.15)**	(5.21)	—	—	—	**(7.57)**	—
Earnings before income taxes	**23.97**	19.83	—	—	—	**21.80**	—
Other International							
Northern Latin America[g]							
Average price realized[9]	**2.58**	2.09	—	—	—	**2.42**	—
Royalties	**(0.10)**	(1.58)	—	—	—	**(0.69)**	—
Operating costs	**(0.13)**	(0.46)	—	—	—	**(0.26)**	—
Operating netback	**2.35**	0.05	—	—	—	**1.47**	—
Depreciation, depletion and amortization	**(1.84)**	(0.79)	—	—	—	**(1.44)**	—
Administrative expenses and other	**0.04**	0.12	—	—	—	**0.08**	—
Earnings before income taxes	**0.55**	(0.62)	—	—	—	**0.11**	—
Total International[l]							
Average price realized[9]	**67.96**	67.42	—	—	—	**67.86**	—
Royalties	**(6.52)**	(19.25)	—	—	—	**(11.17)**	—
Operating costs	**(6.99)**	(8.22)	—	—	—	**(7.44)**	—
Operating netback	**54.45**	39.95	—	—	—	**49.25**	—
Depreciation, depletion and amortization	**(27.02)**	(13.74)	—	—	—	**(22.27)**	—
Administrative expenses and other	**(5.29)**	(5.79)	—	—	—	**(5.46)**	—
Earnings before income taxes	**22.14**	20.42	—	—	—	**21.52**	—

Footnotes and definitions, see page 42

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 operating earnings, cash flow from operations, return on capital employed and cash and total operating costs per barrel data because investors may use this information to analyze operating performance, leverage and liquidity. The additional information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Definitions

(1) Total operations production	– Total operations production includes total production from both mining and in-situ operations.
(2) Average sales price	– This operating statistic is calculated before royalties (where applicable) and net of related transportation costs and excludes the realized impact of hedging activities unless stated.
(3) Cash operating costs	– 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 for total operations (excluding Syncrude), see Management's Discussion and Analysis.
(4) Total cash operating costs	– Include cash operating costs as defined above and cash start-up costs. Per barrel amounts are based on total production volumes.
(5) Total operating costs	– Include total cash operating costs 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.
(9) Average price received	– This operating statistic is calculated before transportation costs and royalties and excludes the impact of hedging activities.

Explanatory Notes

* Excludes the impact of realized hedging activities.

** 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.

*** For the three months ended September 30, 2009, and the twelve months ended December 31, 2009, operating summary information reflects results of operations since the merger with Petro-Canada on August 1, 2009.

**** Users are cautioned that the Syncrude cash costs per barrel measure may not be fully comparable to similar information calculated by other entities (including Suncor's own cash costs per barrel excluding Syncrude) due to differing treatments for operating and capital costs among producers.

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

Metric conversion

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

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