THIRD QUARTER 2009
Report to shareholders for the period ended September 30, 2009

Suncor Energy releases first quarterly results following merger with Petro-Canada

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 23 of Suncor's 2009 third quarter management's discussion and analysis (MD&A). This document makes reference to barrels of oil equivalent (boe). A boe conversion ratio of six thousand cubic feet of natural gas: one barrel of crude oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Accordingly, boe measures may be misleading, particularly if used in isolation.

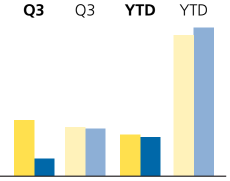
On August 1, 2009, Suncor Energy Inc. completed its merger with Petro-Canada. The three and nine month amounts ending September 30, 2009 reflect results of the post-merger Suncor from August 1, 2009 together with results of legacy Suncor only from January 1 through July 31, 2009. The comparative figures reflect solely the 2008 results of legacy Suncor. For further information with respect to the merger transaction, please refer to note 3 to the September 30, 2009 unaudited interim consolidated financial statements.

Suncor Energy Inc. recorded third quarter 2009 net earnings of $929 million ($0.74 per common share), compared to $815 million ($0.87 per common share) in the third quarter of 2008. Operating earnings(1) in the third quarter of 2009 were $288 million ($0.23 per common share), compared to $810 million ($0.87 per common share) in the third quarter of 2008.

Cash flow from operations(2) was $574 million in the third quarter of 2009, compared to $1.146 billion in the third quarter of 2008.

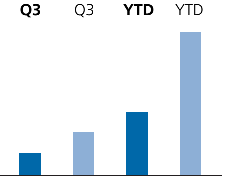
"This was a milestone quarter in Suncor's history and a very productive one as we closed our merger with Petro-Canada and started an extensive integration of our operations across the new company," said Rick George, president and chief executive officer. "The integration work we've completed in just a little over three months is already yielding some significant efficiencies that will enable Suncor to come out of this cycle stronger than ever as a globally competitive energy producer."

Earnings by Quarter
($ millions)



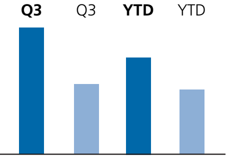
	2009 Q3	2008 Q3	**2009 YTD**	2008 YTD
Net earnings	**929**	815	**689**	2,352
Operating earnings(1)	**288**	810	**646**	2,471

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



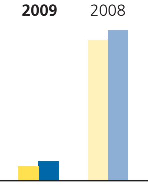
2009 Q3	2008 Q3	**2009 YTD**	2008 YTD
574	1,146	**1,670**	3,826

Production(3)(4)
(thousands of barrels of oil equivalent per day)



2009 Q3	2008 Q3	**2009 YTD**	2008 YTD
507.1	281.0	**386.5**	259.7

Ratios
(percent)
for the twelve months ended September 30



	2009	2008
Return on average shareholder's equity	**2.7**	26.8
Return on capital employed(5)	**3.7**	28.7

(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 23 of our 2009 third quarter MD&A.
(3) Does not include Suncor's proportionate production share from the Syncrude joint venture.
(4) Post-merger production for the final two months of third quarter 2009 averaged 593.2 thousands of boe per day (excluding Suncor's share of the Syncrude joint venture, which averaged 37.4 thousands of boe per day for the final two months of third quarter 2009).
(5) Non-GAAP measure. See page 23 of our 2009 third quarter MD&A.

Operating Earnings

Operating earnings is a non-GAAP measure that the company uses to evaluate operating performance, allowing 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 23 of our 2009 third quarter MD&A for discussion of non-GAAP financial measures.

	Three months ended September 30		Nine months ended September 30	
($ millions, after-tax)	**2009**	2008	**2009**	2008
Net earnings as reported	**929**	815	**689**	2 352
Change in fair value of commodity derivatives	**(237)**	(125)	**435**	(52)
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(386)**	150	**(643)**	207
Mark-to-market valuation of stock-based compensation	**72**	(36)	**116**	(57)
Project start-up costs	**9**	6	**21**	21
Impact of income tax rate adjustments on future income tax liabilities(1)	**152**	—	**152**	—
Costs related to deferral of growth projects	**39**	—	**150**	—
Gain on effective settlement of pre-existing contract with Petro-Canada(2)	**(438)**	—	**(438)**	—
Impact of recording acquired inventory at fair value(3)	**97**	—	**97**	—
Merger and integration costs	**51**	—	**67**	—
Operating earnings	**288**	810	**646**	2 471

(1) Increase in the future income tax liabilities resulting from a revised provincial allocation for income tax purposes due to the merger with Petro-Canada (see note 14 of the September 30, 2009 unaudited interim consolidated financial statements).

(2) Impact from deemed settlement value assigned to bitumen processing contract with Petro-Canada upon close of merger (see note 3 of the September 30, 2009 unaudited interim consolidated financial statements).

(3) 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.

The decrease in operating earnings and cash flow from operations was primarily due to lower price realizations, as benchmark commodity prices were significantly weaker in the third quarter of 2009 compared to the same period in 2008, and higher operating expenses at our oil sands operations as a result of increased production and sales volumes. These factors were partially offset by increased upstream production resulting from the merger with Petro-Canada and improved operational performance in our existing oil sands assets.

Net earnings for the first nine months of 2009 were $689 million compared to $2.352 billion for the same period in 2008. Operating earnings in the first nine months of 2009 were $646 million, compared to $2.471 billion in the first nine months of 2008. Cash flow from operations was $1.670 billion in the first nine months of 2009, compared to $3.826 billion for the same period in 2008. The year-to-date decreases in earnings and cash flow from operations were primarily due to the same factors that impacted third quarter results.

After completion of the merger with Petro-Canada, Suncor's total upstream production during the final two months of the third quarter of 2009 averaged 630,600 barrels of oil equivalent (boe) per day. Additional production resulting from the merger accounted for 289,400 boe per day. Upstream production from Suncor's legacy oil sands and natural gas operations averaged 339,900 boe per day in the third quarter of 2009, compared to 281,000 boe per day in the third quarter of 2008.

Oil Sands production (excluding proportionate production share from the Syncrude joint venture) contributed an average 305,300 barrels per day (bpd) in the third quarter of 2009, compared to third quarter 2008 production of 245,600 bpd. The increased production was primarily due to improved operational reliability in the third quarter of 2009. Production in the comparative quarter of 2008 was negatively impacted by unplanned maintenance shutdowns in our upgrading and extraction assets, as well as wet weather that impacted mine production. Based on results from the first nine months of 2009 and our expectations for the fourth quarter, the Oil Sands production outlook has been narrowed to 290,000 to 305,000 bpd.

As a result of the merger, Suncor holds a 12% share in the Syncrude oil sands joint venture located close to Suncor's existing oil sands operations in Fort McMurray, Alberta.

Syncrude operations contributed an average 37,400 bpd of sweet crude production for August and September, 2009.

After completion of the merger, production from Suncor's natural gas business during the final two months of the third quarter of 2009 averaged 772 million cubic feet equivalent (mmcfe) per day. Additional production resulting from the merger accounted for 563 mmcfe per day. Production from Suncor's legacy natural gas operations averaged 208 mmcfe per day in the third quarter of 2009, compared to 213 mmcfe per day in the third 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.

East Coast Canada production contributed an average 49,600 bpd during the final two months of the third quarter of 2009, while production from our International segment (comprising our assets in the North Sea and other International areas) contributed an average 108,600 bpd during the final two months of the third quarter of 2009. Production for both the East Coast Canada and International segments was lower than capacity primarily as a result of planned and unplanned maintenance and the tie-in of the North Amethyst extension at White Rose.

Cash operating costs for our oil sands operations (excluding Syncrude) averaged $32.25 per barrel in the third quarter of 2009, compared to $34.00 per barrel during the third quarter of 2008. The decrease in cash operating costs per barrel was primarily due to the increase in 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 in the third quarter of 2009. The merger with Petro-Canada did not result in increased oil sands production (excluding Syncrude), as production from MacKay River was included in Suncor's reported production from January 1 to July 31, 2009 as volumes processed by Suncor under a processing fee agreement. Based on results from the first nine months of 2009 and expectations for the fourth quarter, our cash operating costs outlook has been lowered to $32.00 to $34.00 per barrel.

Growth and operational update

As a result of the completion of the merger with Petro-Canada on August 1, 2009, Suncor became Canada's largest energy company and the fifth largest North American-based energy company by market value. The company is now working through capital and operating efficiencies that we expect to result in synergies for operating and capital expenditures. We have also begun the process of reviewing all capital projects with a view to directing capital investment toward projects with the strongest near-term cash flow potential, highest anticipated return on capital and lowest risk.

"These were necessary steps to get us on a footing where we can compete on the global stage as one of the largest independent energy companies in the world," said George. "With our new organization largely in place and our review of investment opportunities well underway, we expect to be in a position to begin translating strategy into action in the coming weeks, at which time we will announce our 2010 capital budget."

As part of its strategic business alignment and subject to Board of Directors approval, Suncor plans 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. Once the natural gas portion of the divestment program is complete, our natural gas assets are expected to provide a solid foundation to support long-term growth in our core oil sands business while targeting a low-cost position among North American natural gas producers, with a growing focus on unconventional gas.

During the third quarter of 2009, the Steepbank extraction plant was completed on schedule and within the revised budget disclosed in our 2009 second quarter report. The plant began operations in late September and is expected to result in improved reliability and productivity within our oil sands business beginning in the fourth quarter of 2009. The Firebag sulphur plant was also completed on schedule and on budget during the third quarter of 2009. It is ready to operate and is expected to support sulphur emissions reductions for existing and planned in-situ development.

Suncor also announced in October 2009, that it is resuming the expansion of its St. Clair Ethanol Plant near Sarnia, Ontario. The $120 million construction project, expected to be completed in late 2010 or early 2011, is expected to double the plant's current ethanol production capacity from 200 to 400 million litres per year.

On August 28, Cow Harbour Construction employee Michael Shannahan died following injuries sustained while working at Suncor's oil sands facility. "This is a harsh reminder that in everything we do, nothing is more important than protecting ourselves and others from harm," said Rick George.

Suncor is cooperating with an investigation into the accident by Alberta Workplace Health and Safety.

Outlook

Suncor's outlook provides management's targets for 2009 in certain key areas of the company's business.

	Nine Month Actuals Ended September 30, 2009	2009 Full Year Outlook
Oil Sands (1), (2)		
Production (bpd)	**294,800**	290,000 to 305,000
Sales		
Diesel	**11%**	11%
Sweet	**36%**	36%
Sour	**49%**	49%
Bitumen	**4%**	4%
Realization on crude sales basket (3)	**WTI @ Cushing less Cdn$5.84 per barrel**	WTI @ Cushing less Cdn$5.50 to Cdn$6.00 per barrel
Cash operating costs (4)	**$32.40 per barrel**	$32.00 to $34.00 per barrel

	Two Month Actuals Ended September 30, 2009	2009 Fourth Quarter Outlook
Natural Gas (5)		
Production (6) (mmcf equivalent per day)	**772**	760 to 775
Natural gas	**88%**	88%
Crude oil and liquids	**12%**	12%
East Coast Canada		
Production (bpd)	**49,600**	60,000 to 65,000
International		
Production (boe per day)	**108,600**	130,000 to 140,000
Crude oil and liquids	**83%**	86%
Natural gas	**17%**	14%

(1) Excludes Suncor's proportionate production share from the Syncrude joint venture. Our post-merger average production share of the Syncrude joint venture for August and September 2009 averaged 37,400 bpd.

(2) Based on third quarter results and expectations for the fourth quarter, the outlook for Oil Sands production, cash operating costs, sales volume split and realization on crude sales basket has been adjusted. The June 30 Oil Sands production outlook was 300,000 (+5%/-10%) with a corresponding cash operating costs range of $33.00 to $38.00. The sales volume split was diesel 10%, sweet 38%, sour 49% and bitumen 3% and the realization on crude sales basket was WTI @ Cushing less Cdn$4.50 to Cdn$5.50.

(3) Excludes the impact of hedging activities.

(4) Cash operating cost estimates are based on the following assumptions: (i) production volumes and sales mix as described in the table above; and (ii) a natural gas price of $3.53 per gigajoule ($3.73 per mcf) at AECO. Based on third quarter results and expectations for the balance of the year, the natural gas price assumption has been reduced from the previous $4.50 per gigajoule at AECO. Until July 31, 2009 this target included costs incurred for third-party bitumen processing. This goal does not include costs related to deferral of growth projects.

(5) To provide context for our fourth quarter production outlook for all of our natural gas properties, post-merger average production over August and September 2009 is provided. Average production for legacy Suncor's natural gas assets in the first nine months of 2009 was 212 mmcf equivalent per day, with 92% natural gas and 8% liquids.

(6) 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, assumptions and year-to-date performance for the 2009 fiscal year and is subject to change. Assumptions are based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be relevant. Assumptions for the Oil Sands 2009 full year outlook include reliability and operational efficiency initiatives which we expect to minimize unplanned maintenance in 2009. Assumptions for the Natural Gas, East Coast Canada and International 2009 fourth quarter outlook include reservoir performance, drilling results, facility reliability, changes in OPEC production quotas and successful execution of planned turnarounds.

Factors that could potentially impact Suncor's operations and financial performance for the remainder of 2009 include:

- Bitumen supply. Ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage and in-situ reservoir performance could impact 2009 production targets.
- 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.
- Crude oil hedges. Suncor has hedging agreements for approximately 160,000 bpd for the remainder of 2009 and for 50,000 bpd in 2010. For further details of our hedging activities, see page 20 in Suncor's third quarter MD&A.
- 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 table 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 25 in Suncor's third quarter MD&A.

Management's Discussion and Analysis

November 5, 2009

This Management's Discussion and Analysis (MD&A) contains forward-looking information based on certain expectations, estimates, projections and assumptions. This information is subject to a number of risks and uncertainties, many of which are beyond the company's control. Users of this information are cautioned that actual results may differ materially. For information on material risk factors and assumptions underlying our forward-looking information, see page 25.

This MD&A should be read in conjunction with our September 30, 2009 unaudited interim consolidated financial statements and notes. Readers should also refer to our MD&A for the year ended December 31, 2008 and to our Annual Information Form (AIF) dated March 2, 2009. All financial information is reported in Canadian dollars (Cdn$) and in accordance with Canadian generally accepted accounting principles (GAAP) unless noted otherwise. The financial measures: operating earnings, cash flow from operations, return on capital employed (ROCE), and cash and total operating costs per barrel referred to in this MD&A are not prescribed by GAAP and are outlined and reconciled in Non-GAAP Financial Measures on pages 23 to 25 of this MD&A and page 40 of our 2008 Annual Report.

References to "we," "our," "us," "Suncor," or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships and joint venture investments, unless the context otherwise requires. References to "legacy Suncor" and "legacy Petro-Canada" refer to the applicable entity prior to the August 1, 2009 effective date of the merger.

On August 1, 2009, Suncor completed its merger with Petro-Canada. All closing conditions were satisfied, including approvals from shareholders, the Alberta Court of Queen's Bench, and the Competition Bureau of Canada. Under the terms of the merger, Petro-Canada shareholders received 1.28 Suncor common shares for each Petro-Canada common share held. For further information with respect to the merger transaction, please refer to note 3 of the September 30, 2009 unaudited interim consolidated financial statements.

The consolidated financial statements include the results of post-merger Suncor from August 1, 2009. As such, the three and nine month amounts ending September 30, 2009 reflect results of the post-merger Suncor from August 1, 2009 together with results of legacy Suncor only from January 1, 2009 through July 31, 2009. The comparative figures reflect solely the 2008 results of legacy Suncor.

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

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

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

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

Selected Financial Information

Industry Indicators

(average for the period)	Three months ended September 30 2009	2008	Nine months ended September 30 2009	2008
West Texas Intermediate (WTI) crude oil US$/barrel at Cushing	**68.30**	118.00	**57.00**	113.30
Dated Brent crude oil US$/barrel at Sullom Voe	**68.25**	114.80	**57.15**	111.00
Dated Brent/Maya FOB price differential US$/barrel	**5.10**	8.35	**4.90**	14.15
Canadian 0.3% par crude oil Cdn$/barrel at Edmonton	**70.60**	123.00	**62.00**	115.90
Edmonton Light/WCS FOB price differential Cdn$/barrel	**8.80**	18.35	**8.15**	21.05
Light/heavy crude oil differential US$/barrel WTI at Cushing less Western Canadian Select at Hardisty	**10.10**	18.05	**8.85**	20.40
Natural Gas US$/mcf at Henry Hub	**3.40**	10.10	**3.90**	9.65
Natural Gas (Alberta spot) Cdn$/mcf at AECO	**3.00**	9.25	**4.10**	8.55
New York Harbour 3-2-1 crack (1) US$/barrel	**7.50**	10.65	**8.55**	10.30
Chicago 3-2-1 crack (1) US$/barrel	**7.65**	16.45	**8.90**	12.15
Seattle 3-2-1 crack (1) US$/barrel	**12.80**	14.70	**13.20**	14.40
Exchange rate: US$/Cdn$	**0.91**	0.96	**0.86**	0.98

(1) 3-2-1 crack spreads are industry indicators measuring the margin on a barrel of oil for gasoline and distillate. They are calculated by taking two times the gasoline margin at a certain location plus one times the distillate margin at that same location and dividing by three.

Outstanding Share Data(1) (at September 30, 2009)

Common shares	1 558 900 869
Common share options – total	73 784 398
Common share options – exercisable	44 813 379

(1) For information on the impact to our common share and common share option balances as a result of the merger with Petro-Canada, see note 9 of the September 30, 2009 unaudited interim consolidated financial statements.

Summary of Quarterly Results

($ millions, except per share)	Three months ended Sept 30 2009	June 30 2009	Mar 31 2009	Dec 31 2008	Sept 30 2008	June 30 2008	Mar 31 2008	Dec 31 2007
Revenues(1)	**8 443**	4 768	4 633	6 952	8 507	7 640	5 539	4 844
Net earnings (loss)	**929**	(51)	(189)	(215)	815	829	708	1 042
Net earnings (loss) per common share								
Basic	**0.74**	(0.06)	(0.20)	(0.24)	0.87	0.89	0.77	1.12
Diluted	**0.74**	(0.06)	(0.20)	(0.24)	0.86	0.87	0.75	1.10

(1) Net of royalties.

Analysis of Consolidated Statements of Earnings and Cash Flows

Net earnings for the third quarter of 2009 were $929 million, compared to net earnings of $815 million for the third quarter of 2008. Operating earnings for the third quarter of 2009 were $288 million, compared to $810 million in the third quarter of 2008. Cash flow from operations in the third quarter of 2009 was $574 million, compared to $1.146 billion in the same period of 2008.

Operating Earnings

Operating earnings is a non-GAAP measure that the company uses to evaluate operating performance, allowing 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.

($ millions, after-tax)	Three months ended September 30		Nine months ended September 30	
	2009	2008	**2009**	2008
Net earnings as reported	**929**	815	**689**	2 352
Change in fair value of commodity derivatives	**(237)**	(125)	**435**	(52)
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(386)**	150	**(643)**	207
Mark-to-market valuation of stock-based compensation	**72**	(36)	**116**	(57)
Project start-up costs	**9**	6	**21**	21
Impact of income tax rate adjustments on future income tax liabilities (1)	**152**	—	**152**	—
Costs related to deferral of growth projects	**39**	—	**150**	—
Gain on effective settlement of pre-existing contract with Petro-Canada (2)	**(438)**	—	**(438)**	—
Impact of recording acquired inventory at fair value (3)	**97**	—	**97**	—
Merger and integration costs	**51**	—	**67**	—
Operating earnings	**288**	810	**646**	2 471

(1) Impact from an increase in the future income tax liability resulting from a revised provincial allocation for income tax purposes because of the merger with Petro-Canada (see note 14 of the September 30, 2009 unaudited interim consolidated financial statements).

(2) Impact from deemed settlement value assigned to bitumen processing contract with Petro-Canada upon close of merger (see note 3 of the September 30, 2009 unaudited interim consolidated financial statements).

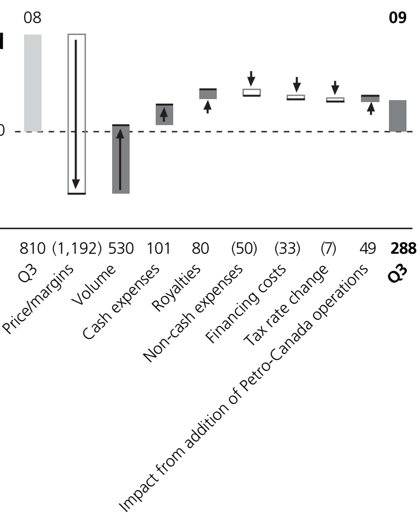
(3) Inventory acquired through the merger at fair value was sold during the third quarter of 2009, resulting in a one-time negative impact to earnings.

The decrease in earnings and cash flow from operations was primarily due to lower commodity price realizations, as benchmark prices were significantly weaker in the third quarter of 2009 compared to the same period in 2008, and operating expenses were higher in our Oil Sands segment due to increased production and sales volumes. These factors were partially offset by increased production resulting from the merger with Petro-Canada and improved operational performance in our existing oil sands assets.

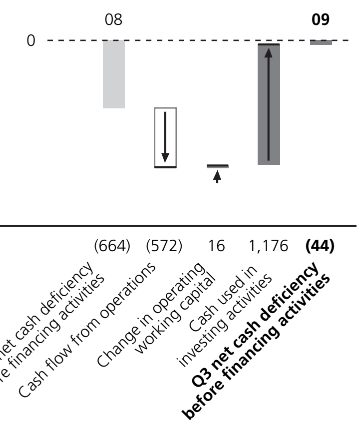
Net earnings for the first nine months of 2009 were $689 million compared to $2.352 billion for the same period in 2008. Operating earnings in the first nine months of 2009 were $646 million, compared to $2.471 billion in the first nine months of 2008. Cash flow from operations was $1.670 billion in the first nine months of 2009, compared to $3.826 billion for the same period in 2008. The year-to-date decreases in earnings and cash flow from operations were primarily due to the same factors that impacted third quarter results.

Our effective tax rate for the first nine months of 2009 was 14%, compared to 29% in the first nine months of 2008. The lower effective tax rate for the first nine months of 2009 compared to 2008 is primarily a result of foreign exchange gains on our U.S. dollar denominated long-term debt being taxed at a lower capital gains rate, no tax impact relating to the gain on effective settlement of the pre-existing contract with Petro-Canada, and tax filing reconciliations.

Bridge Analysis of Consolidated Operating Earnings
($ millions)



Bridge Analysis of Consolidated Net Cash Flow
($ millions)



Analysis of Segmented Earnings and Cash Flows

For comparability purposes, readers should rely on the reported net earnings presented in our September 30, 2009 unaudited interim consolidated financial statements and notes in accordance with Canadian GAAP.

Oil Sands

	Three months ended September 30		Nine months ended September 30	
($ millions, after-tax)	**2009**	2008	**2009**	2008
Oil Sands net earnings as reported	**738**	854	**321**	2 300
Change in fair value of commodity derivatives	**(237)**	(125)	**435**	(52)
Mark-to-market valuation of stock-based compensation	**19**	(5)	**28**	(13)
Project start-up costs	**9**	6	**21**	21
Impact of income tax rate adjustments on future income tax liabilities (1)	**140**	—	**140**	—
Costs related to deferral of growth projects	**39**	—	**150**	—
Gain on effective settlement of pre-existing contract with Petro-Canada (2)	**(438)**	—	**(438)**	—
Impact of recording acquired inventory at fair value (3)	**5**	—	**5**	—
Oil Sands operating earnings	**275**	730	**662**	2 256

(1) Impact from an increase in the future income tax liability resulting from a revised provincial allocation for income tax purposes because of the merger with Petro-Canada (see note 14 of the September 30, 2009 unaudited interim consolidated financial statements).

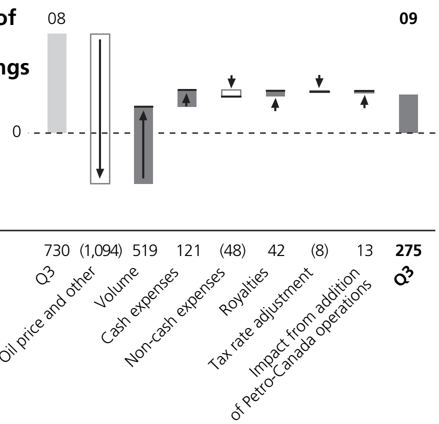
(2) Impact from deemed settlement value assigned to bitumen processing contract with Petro-Canada upon close of merger (see note 3 of the September 30, 2009 unaudited interim consolidated financial statements).

(3) 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.

Oil Sands recorded net earnings of $738 million in the third quarter of 2009, compared with $854 million in the third quarter of 2008. Operating earnings for the third quarter of 2009 were $275 million, compared to $730 million in the third quarter of 2008. Earnings decreased primarily as a result of lower average price realizations for oil sands crude products, partially offset by higher production.

The decrease in price realizations reflects significantly lower benchmark West Texas Intermediate (WTI) crude oil prices and a decreased premium to WTI on our sweet crude blends, partially offset by a smaller discount to WTI for our sour crude blends, increased sales of higher value sweet crude products, and a weaker Canadian dollar.

Bridge Analysis of Oil Sands Operating Earnings
($ millions)



Overall cash expenses were lower in the third quarter of 2009 compared to the same period of 2008, primarily due to decreased purchases of crude oil and products, partially offset by increased cash operating expenses. Purchases of crude oil and products decreased due primarily to the absence of unplanned shutdowns, as the comparative quarter of 2008 saw higher purchases of diesel and bitumen to meet customer commitments. In addition, in the third quarter of 2008, Suncor purchased product from legacy Petro-Canada to upgrade at Suncor facilities.

The increase in cash operating expenses was due primarily to costs associated with higher production and sales volumes in legacy Suncor operations, as well as the addition of operating costs for MacKay River and Syncrude. In addition, we incurred costs related to the planned implementation of reliability and operational efficiency initiatives, increased employee costs resulting from a larger number of employees and higher overall salaries, as well as further safe mode costs (see page 12). These factors were partially offset by lower energy input costs and cost reduction initiatives in the business.

Non-cash expenses increased during the third quarter of 2009 as compared to the third quarter of 2008, due primarily to increased depreciation, depletion and amortization (DD&A) expense. The increase resulted from continued growth in the depreciable cost base for our oil sands facilities, including the addition of facilities for MacKay River and Syncrude as a result of the merger with Petro-Canada.

Alberta Crown royalty expense decreased in the third quarter of 2009, compared to the third quarter of 2008, primarily due to lower benchmark WTI prices, partially offset by increased production. For a further discussion of Crown royalties, see page 12.

Cash flow from operations was $242 million in the third quarter of 2009, compared to $1.030 billion in the third quarter of 2008. The decrease was due primarily to the same factors that impacted earnings.

Net earnings for the first nine months of 2009 were $321 million, compared to $2.300 billion in the first nine months of 2008. Operating earnings for the first nine months of 2009 were $662 million, compared to $2.256 billion in the same period of 2008. Cash flow from operations for the first nine months 2009 decreased to $896 million from $3.186 billion in the first nine months of 2008. The year-to-date decreases in earnings and cash flow from operations were due primarily to the same factors that impacted third quarter results.

Oil Sands Production(1)

	Three months ended September 30		Nine months ended September 30	
Thousands of barrels per day	**2009**	2008	**2009**	2008
Total	**305.3**	245.6	**294.8**	222.6

	Two months ended September 30
Thousands of barrels per day	**2009**
Syncrude	**37.4**

(1) Unless otherwise stated, discussion of Oil Sands production does not include Suncor's proportionate production share, sales volumes or cash operating costs from the Syncrude joint venture

Oil Sands production averaged 305,300 barrels per day (bpd) in the third quarter of 2009, compared to 245,600 bpd during the third quarter of 2008. The increased production was primarily due to improved operational reliability in the third quarter of 2009. Production in the comparative quarter of 2008 was negatively impacted by unplanned maintenance shutdowns in our upgrading and extraction assets, as well as wet weather that impacted mine production. Based on results from the first nine months of 2009 and our expectations for the fourth quarter, the Oil Sands production outlook has been narrowed to 290,000 to 305,000 bpd.

As a result of the merger, Suncor holds a 12% share in the Syncrude joint venture oil sands operations located close to Suncor's existing oil sands operations in Fort McMurray, Alberta, Canada. Syncrude operations contributed an average 37,400 bpd of sweet crude production for August and September, 2009.

The merger with Petro-Canada did not result in increased oil sands production (excluding Syncrude), as production from MacKay River was included in Suncor's reported production from January 1 to July 31, 2009 as volumes processed by Suncor under a processing fee agreement. However, the addition of MacKay River has resulted in increased sales volumes for Oil Sands, as volumes under the processing agreement were not included in sales from January 1 to July 31, 2009.

Sales volumes during the third quarter of 2009 averaged 287,600 bpd, compared with 219,000 bpd during the third quarter of 2008. The increase was due primarily to increased production and the addition of sales volumes from MacKay River as a result of the merger. The proportion of higher value diesel and sweet crude products increased to 44% of total sales volume in the third quarter of 2009, compared to 27% in the third quarter of 2008 as a result of improved operational reliability in the third quarter of 2009. In addition, in the comparative quarter of 2008, an unplanned shutdown of hydrogen facilities adversely affected the sales mix. Based on year-to-date results and expectations for the fourth quarter, our sales volume split outlook has been adjusted to diesel 11%, sweet 36%, sour 49% and bitumen 3%.

The average price realization for oil sands crude products from Suncor's operated assets decreased to $61.70 per barrel in the third quarter of 2009, compared to $116.32 per barrel in the third quarter of 2008. This was primarily due to a significant decrease in the average benchmark WTI crude oil price of about 42% and a decreased premium to WTI on our sweet crude blends. These factors were partially offset by a smaller discount to WTI for our sour crude blends, a change in sales mix which reflected a larger portion of higher priced sweet products, and the positive impact of the weaker Canadian dollar, as we received higher revenues for our production sold based on U.S. dollar benchmark prices. Based on year-to-date results and expectations for the fourth quarter of 2009, the oil sands realization on crude sales basket outlook has been adjusted to WTI @ Cushing less Cdn$5.50 to Cdn$6.00 per barrel.

During the third quarter of 2009, cash operating costs averaged $32.25 per barrel, compared to $34.00 per barrel during the third quarter of 2008. The decrease in cash operating costs per barrel was primarily due to the increase in 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 in the third quarter of 2009. Cash operating costs per barrel does not include costs related to deferral of growth projects. Based on results from the first nine months of 2009 and expectations for the fourth quarter, our cash operating costs outlook has been lowered to $32.00 to $34.00 per barrel. Refer to page 23 to 25 for further details on cash operating costs as a non-GAAP financial measure, including the calculation and reconciliation to GAAP measures.

A planned maintenance shutdown of a vacuum unit at one of our upgrading facilities commenced on September 8, 2009, and was completed ahead of schedule on October 3, 2009, affecting overall production in the third and fourth quarters of 2009.

Oil Sands Growth Update

With the closure of the merger with Petro-Canada on August 1, 2009, we have begun the process of reviewing all capital projects with a view to directing capital investment toward projects with the strongest near-term cash flow potential, highest anticipated return on capital and lowest risk.

This process is expected to be completed in the coming weeks, at which time we will announce our 2010 capital budget.

During the third quarter of 2009, the Steepbank extraction plant was completed on schedule and within the revised budget disclosed in our 2009 second quarter report. The plant began operations in late September, after commissioning, and is expected to result in improved reliability and productivity within our oil sands business beginning in the fourth quarter of 2009. The Firebag sulphur plant was also completed on schedule and on budget during the third quarter of 2009. It is ready to operate and is expected to support sulphur emissions reductions for existing and planned in-situ development.

For an update on our significant capital projects currently in progress see page 19.

The Oil Sands segment continued 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 $270 million were incurred in the first nine months of 2009. These costs are expected to total between $300 million and $400 million on a pre-tax basis in 2009.

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 2009 and 2010 for three price scenarios, and certain assumptions on which we have based our estimates for those price scenarios.

WTI Price/bbl US$ [(1)]	**60**	**70**	**80**
Natural gas (Alberta spot) Cdn$/mcf at AECO	5.50	6.00	6.50
Light/heavy oil differential of WTI at Cushing less Maya at the U.S. Gulf Coast US$	6.00	9.00	11.50
Differential of Maya at the U.S. Gulf Coast less Western Canadian Select at Hardisty, Alberta US$	3.00	3.00	3.00
US$/Cdn$ exchange rate	0.85	0.90	0.95
Crown Royalty Expense (based on percentage of total Oil Sands gross revenue) %			
2009 – Bitumen (mining old rates – 25% and 1% min; in-situ new rates)	7-8	7-9	8-9
2010 – Bitumen (new rates – with limits for mining only)	5-6	7-9	8-10

(1) For 2009, estimated royalty rates are based on actual year-to-date results plus forward months estimated as per assumptions.

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 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. The final regulations are being developed by the Crown that will establish the bitumen valuation methodology for 2010 and future years. For Suncor's mining operations, the bitumen valuation methodology is based on the terms of Suncor's January 2008 Royalty Amending Agreement, which we believe places certain limitations on the interim bitumen valuation methodology as recently enacted. For the first nine months of 2009, royalties payable to the Crown for our mining operations have been determined in accordance with the interim bitumen valuation methodology. We continue discussions with the Crown to calculate this royalty based on the provisions of our Royalty Amending Agreement, which we currently believe would reduce the royalties payable to the Crown for 2009.

(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. In addition, since our in-situ operations are forecast to remain in pre-payout royalty for the near term, the changes in the Allowed Cost regulations will not have a near term impact on royalty payments. However, potential changes 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 AIF dated March 2, 2009.

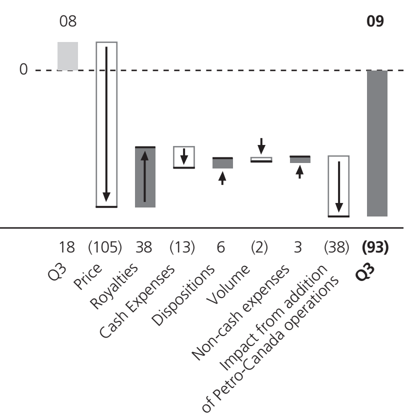
Natural Gas

($ millions, after-tax)	Three months ended September 30 **2009**	2008	Nine months ended September 30 **2009**	2008
Natural Gas net earnings (loss) as reported	**(111)**	18	**(149)**	89
Mark-to-market valuation of stock-based compensation	**9**	—	**9**	(1)
Impact of income tax rate adjustments on future income tax liabilities(1)	**9**	—	**9**	—
Natural Gas operating earnings (loss)	**(93)**	18	**(131)**	88

(1) Impact from an increase in the future income tax liability resulting from a revised provincial allocation for income tax purposes because of the merger with Petro-Canada (see note 14 of the September 30, 2009 unaudited interim consolidated financial statements).

Natural Gas recorded a net loss of $111 million in the third quarter of 2009, compared with net earnings of $18 million during the third quarter of 2008. Operating loss for the third quarter of 2009 was $93 million, compared to operating earnings of $18 million in the third quarter of 2008. The decrease in operating earnings was primarily due to reduced revenues resulting from significantly lower benchmark commodity prices, lower sulphur revenue and higher dry hole costs. This was partially offset by lower royalty expense in the third quarter of 2009 compared to the third quarter of 2008. The decrease in royalties is a result of lower revenues, royalty credits and reduced rates due to the implementation of the Alberta New Royalty Framework.

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



Cash flow from operations for the third quarter of 2009 was $74 million, compared to $98 million in the third quarter of 2008. The decrease was primarily due to the same factors that affected net earnings, excluding the impact of dry hole costs. The net loss for the first nine months of 2009 was $149 million, compared to net earnings of $89 million in the first nine months of 2008. Operating loss for the first nine months of 2009 was $131 million, compared to operating earnings of $88 million in the same period of 2008. Cash flow from operations for the first nine months of 2009 decreased to $169 million from $304 million in the first nine months of 2008. The year-to-date decreases in earnings and cash flow from operations were primarily due to the same factors that impacted third quarter results.

Natural Gas Production	Three months ended September 30		Nine months ended September 30	
Average mmcfe per day	**2009**	2008	**2009**	2008
Legacy Suncor operations	**208**	213	**212**	223

	Two months ended September 30
Average mmcfe per day	**2009**
Legacy Petro-Canada Western Canada	**481**
Legacy Petro-Canada U.S. Rockies	**82**
Total legacy Petro-Canada Natural Gas production	**563**

After completion of the merger with Petro-Canada, Suncor's natural gas production during August and September averaged 772 million cubic feet equivalent (mmcfe) per day. Additional production resulting from the merger accounted for 563 mmcfe per day. Production from Suncor's legacy natural gas operations averaged 208 mmcfe per day in the third quarter of 2009 (209 mmcfe per day during August and September), compared to 213 mmcfe per day in the third quarter of 2008. The decreased production was primarily due to shut-in production in the Elmworth area as a result of low commodity prices and the sale of certain non-core assets in the second quarter of 2009.

Realized natural gas prices in the third quarter of 2009 were $2.81 per thousand cubic feet (mcf), compared to $9.10 per mcf in the third quarter of 2008, reflecting significantly lower benchmark prices.

As part of its strategic business alignment and subject to Board of Directors approval, Suncor plans to divest of a number of non-core natural gas assets. The proposed divestments identified to date include certain natural gas assets in Western Canada and the United States Rockies. Once the natural gas portion of the divestment program is complete, our natural gas assets are expected to provide a solid foundation to support long-term growth in our core oil sands business while targeting a low-cost position among North American natural gas producers, with a growing focus on unconventional gas.

East Coast Canada

	Three months ended September 30
($ millions, after-tax)	**2009**
East Coast Canada net earnings as reported	**39**
Mark-to-market valuation of stock-based compensation	**1**
Impact of recording acquired inventory at fair value(1)	**17**
East Coast Canada operating earnings	**57**

(1) 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.

Net earnings for East Coast Canada were $39 million in the third quarter of 2009, while operating earnings for the third quarter of 2009 were $57 million. Cash flow from operations for the third quarter of 2009 was $130 million. Lower than capacity production as a result of planned and unplanned maintenance, as well as the tie-in of the North Amethyst extension at White Rose, adversely impacted earnings in the quarter.

East Coast Canada Production

	Two months ended September 30
Barrels per day	**2009**
Terra Nova	**16 000**
Hibernia	**28 500**
White Rose	**5 100**
Total East Coast Canada production	**49 600**

In the two months ended September 30, 2009, East Coast Canada production averaged 49,600 bpd. Terra Nova production averaged 16,000 bpd, with production impacted by planned and unplanned maintenance during the two months ended September 30, 2009. Production from Hibernia averaged 28,500 bpd for the two months ended September 30, 2009, with strong reservoir capability and facility reliability in the period. White Rose production averaged 5,100 bpd during the two months ended September 30, 2009, with production negatively impacted by planned downtime for maintenance and the tie-in of the North Amethyst extension.

Sales volumes in the two months ended September 30, 2009 averaged 49,400 bpd, impacted by the same factors affecting production.

The East Coast Canada segment's average realized crude oil price was $75.22 per barrel in the third quarter of 2009.

East Coast Canada Royalties

WTI Price/bbl (US$)[1]	**60**	**70**	**80**
US$/Cdn$ exchange rate	0.85	0.90	0.95
Crown Royalty Expense (based on percentage of gross revenue) %			
2009 – Crude (tiered royalty rates assessed on gross or net revenue)	27-29	28-30	29-31
2010 – Crude (tiered royalty rates assessed on gross or net revenue)	32-34	33-35	34-36

(1) For 2009, estimated royalty rates are based on actual year-to-date results plus forward months estimated as per assumptions.

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 royalty payments 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.

In the third quarter of 2009, East Coast Canada royalties averaged 28% of gross revenue. Terra Nova production was subject to a Tier I royalty of 30% of net revenue and a Tier II royalty of an incremental 12.5% of net revenue. White Rose production was subject to a Tier I royalty of 20% of net revenue and a Tier II royalty of 10% of net revenue. The royalty rate on Hibernia production increased from 5% of gross revenue to 30% of net revenue during 2009 based on the terms of the Hibernia Royalty Agreement and a Memorandum of Understanding. In addition, Hibernia production was subject to a federal government net profits interest of up to 10% of net revenue.

A planned shutdown at our Terra Nova facility commenced in mid September, and was completed ahead of schedule in early October, affecting overall production in the third and fourth quarters of 2009.

A twelve-day shutdown planned for October at the Hibernia facility has been deferred to 2010.

Production from White Rose continued to be impacted during August and September after completion of the planned turnaround, as the South Drill Center remained shut-in until early October for a planned tie-in of the North Amethyst extension, affecting overall production in the third and fourth quarters of 2009.

East Coast Canada Growth Update

Installation of subsea infrastructure is complete and development drilling has commenced for the North Amethyst portion of the White Rose Extensions, with the project on schedule for early 2010. Development drilling of North Amethyst will continue through 2010 and 2011.

Engineering and design activities continued for the Hebron project during the third quarter of 2009.

Drilling commenced during the third quarter of 2009 on the Hibernia South Extension project, with anticipated production starting in late 2009 or early 2010.

International

($ millions, after-tax)	Three months ended September 30 2009
International net earnings as reported	**32**
Mark-to-market valuation of stock-based compensation	**6**
Impact of recording acquired inventory at fair value(1)	**8**
International operating earnings	**46**

(1) 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.

In the third quarter of 2009, International recorded net earnings of $32 million, while operating earnings were $46 million. Lower than capacity production and high operating costs due to maintenance and dry hole costs adversely impacted earnings in the quarter.

Cash flow from operations for the third quarter of 2009 was $163 million, impacted by the same factors affecting earnings, with the exception of dry hole costs.

International Production

Boe per day	Two months ended September 30 2009
U.K. sector of the North Sea	**40 800**
The Netherlands sector of the North Sea	**13 800**
Total North Sea	**54 600**
Other International	**54 000**
Total International production	**108 600**

International production averaged 108,600 boe per day in the two months ended September 30, 2009. Buzzard production in the North Sea averaged 29,400 boe per day in the two months ended September 30, 2009, impacted by a planned four-week shutdown in the quarter. In the Netherlands sector of the North Sea, production was 13,800 boe per day for the two months ended September 30, 2009.

Other International consists of our producing assets in Libya and Trinidad and Tobago. Production in Libya averaged 42,700 boe per day in the two months ended September 30, 2009, with production impacted by OPEC quota constraints. Trinidad and Tobago offshore gas production averaged 67.8 mmcf per day in the two months ended September 30, 2009, with high demand from the Atlantic liquefied natural gas (LNG) terminal in the period.

The average realized price for the North Sea was $68.67 per barrel in the third quarter of 2009, while the average realized price for Other International was $62.40 per barrel of oil equivalent.

During the two months ended September 30, 2009, planned maintenance shutdowns occurred at the Buzzard and Hanze facilities in the North Sea, resulting in reduced production. Operations have since commenced and no further impact is expected. In late September 2009, planned turnaround and maintenance commenced at the Triton facility and was completed in early October, affecting overall production in the third and fourth quarters of 2009.

International Growth Update

The Syria Ebla Gas Project remains on plan for first gas delivery in mid-2010 and was 80% complete at the end of the third quarter of 2009. Five wells have been completed and are ready for production. In addition, the 3D seismic acquisition of the Cherrife field was completed at the end of the third quarter of 2009.

Work has now commenced on implementing the projects associated with the new Libya Exploration and Production Sharing Agreements (EPSAs), with a focus on preparing the EPSA field development programs and initiating the new exploration program. Work on the exploration program is progressing, with three seismic surveys completed during the quarter and another three seismic crews continuing to acquire data in country.

As part of its strategic business alignment and subject to Board of Directors approval, Suncor plans to divest of a number of non-core assets. The proposed divestments identified to date include all Trinidad and Tobago assets and certain non-core North Sea assets.

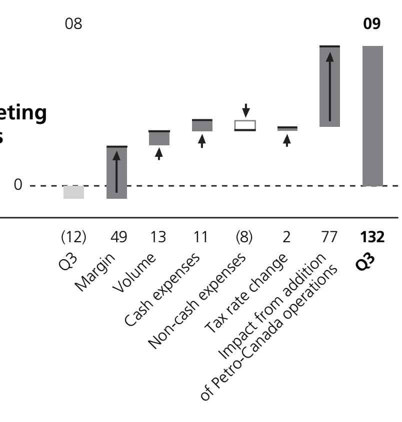
Refining and Marketing

($ millions, after-tax)	Three months ended September 30 2009	2008	Nine months ended September 30 2009	2008
Refining and Marketing net earnings (loss) as reported	**51**	(11)	**275**	169
Mark-to-market valuation of stock-based compensation	**14**	(1)	**15**	(2)
Impact of recording acquired inventory at fair value(1)	**67**	—	**67**	—
Refining and Marketing operating earnings (loss)	**132**	(12)	**357**	167

(1) 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.

Refining and Marketing recorded 2009 third quarter net earnings of $51 million, compared to a net loss of $11 million in the third quarter of 2008. Operating earnings for the third quarter of 2009 were $132 million, compared to an operating loss of $12 million in the third quarter of 2008. The increase in operating earnings was primarily due to the addition of assets associated with the company's merger with Petro-Canada in the third quarter of 2009. In addition, our margins improved as a result of increased operational reliability at both the Sarnia and Commerce City refineries that enabled us to process more lower-priced crude instead of purchasing refined products.

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



After completion of the merger, total sales of refined petroleum products during August and September 2009 averaged 87.5 million litres per day. Additional sales resulting from the merger accounted for 53.4 million litres per day. Total sales of refined petroleum products from Suncor's legacy refining and marketing operations averaged 34.1 million litres per day during August and September 2009, compared to 32.0 million litres per day in the third quarter of 2008. This increase in sales was primarily due to increased demand and improved operational reliability as compared to the third quarter of 2008.

Refining and Product Supply contributed operating earnings of $98 million in the third quarter of 2009, up from an operating loss of $21 million in the same quarter of 2008. The increase was due primarily to increased production resulting from the addition of the Edmonton and Montreal refineries, and the lubricants plant, as a result of the merger. In addition, improved operational reliability at our existing Sarnia and Commerce City refineries resulted in higher margins, as we were able to process more lower-price crude. Lower reliability levels in the comparative quarter of 2008 resulted in higher purchases of refined product to meet customer commitments, and this negatively impacted our margins in that period.

Marketing contributed operating earnings of $34 million in the third quarter of 2009, up from $9 million in the same quarter of 2008. The increase was due primarily to the addition of the national Retail and Wholesale operations and the Lubricants business as a result of the merger with Petro-Canada during the third quarter of 2009.

Cash flow from operations was $275 million in the third quarter of 2009, compared to $19 million in the third quarter of 2008. The increase was primarily due to the same factors that affected net earnings during the quarter. Net earnings for the first nine months of 2009 were $275 million, compared to $169 million in the first nine months of 2008. Operating earnings for the first nine months of 2009 were $357 million, compared to $167 million in the same period of 2008. Cash flow from operations for the first nine months of 2009 increased to $695 million from $429 million in the first nine months of 2008. The year-to-date changes in earnings and cash flow from operations were primarily due to the same factors that impacted third quarter results, in addition to increased refined product sales from our legacy Suncor refineries.

During August 2009, an unplanned shutdown occurred at the Edmonton refinery and an unplanned outage occurred at the Sarnia refinery, resulting in reduced throughput. Operations have since commenced and no further impact is expected. In the fourth quarter of 2009, planned turnarounds are scheduled for the Montreal and Commerce City refineries. As with all planned refining turnarounds, supply arrangements are in place to meet market demand during these outages.

Corporate, Energy Trading and Eliminations

($ millions, after-tax)	Three months ended September 30 2009	2008	Nine months ended September 30 2009	2008
Corporate, energy trading and eliminations net earnings (loss) as reported	**180**	(46)	**171**	(206)
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(386)**	150	**(643)**	207
Mark-to-market valuation of stock-based compensation	**23**	(30)	**57**	(41)
Impact of income tax rate adjustments on future income tax liabilities(1)	**3**	—	**3**	—
Merger and integration costs	**51**	—	**67**	—
Corporate, energy trading and eliminations operating earnings (loss)	**(129)**	74	**(345)**	(40)

(1) Impact from an increase in the future income tax liability resulting from a revised provincial allocation for income tax purposes because of the merger with Petro-Canada (see note 14 of the September 30, 2009 unaudited interim consolidated financial statements).

Corporate, Energy Trading and Eliminations recorded an operating loss of $129 million in the third quarter of 2009, compared to operating earnings of $74 million in the third quarter of 2008. Results reflected higher net interest expense in the third quarter of 2009 due to additional debt acquired through the merger with Petro-Canada and the expensing of $134 million of interest costs relating to growth projects now in safe mode. In addition, results reflected lower energy trading earnings and an increase in profits eliminated on crude oil sales between upstream segments and Refining and Marketing, where this crude oil still resides in Refining and Marketing's inventories.

Breakdown of Corporate Net Earnings

($ millions, after-tax)	Three months ended September 30 2009	2008
Corporate net earnings (loss)	**222**	(115)
Energy trading	**25**	57
Group eliminations	**(67)**	12
Total net earnings (loss)	**180**	(46)

Energy trading activities resulted in net pre-tax earnings of $35 million in the third quarter of 2009, compared to $85 million in the third quarter of 2008, due primarily to a decrease in earnings on our crude trading activities.

Cash used in operations was $310 million in the third quarter of 2009, compared to $1 million in the third quarter of 2008.

Corporate net earnings were $171 million in the first nine months of 2009, compared to a net loss of $206 million in the same period of 2008. Operating loss for the first nine months of 2009 was $345 million, compared to $40 million in the same period of 2008. Cash used in operations for the first nine months of 2009 increased to $383 million from $93 million in the first nine months of 2008. The year-to-date changes in earnings and cash flow used in operations were primarily due to the same factors that impacted third quarter results.

Cash Income Taxes

We estimate we will have cash income taxes of approximately $900 million to $1.0 billion during 2009. Cash income taxes are sensitive to crude oil and natural gas commodity price volatility and the timing of deductibility of capital expenditures for income tax purposes, among other things. This estimate is based on the following assumptions: current forecasts of production, capital and operating costs and the commodity prices and exchange rates described in the royalty estimate tables on page 12 and 15, 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.

Analysis of Financial Condition and Liquidity

Our capital resources consist primarily of cash flow from operations and available lines of credit. As a result of the merger with Petro-Canada, we added approximately $4.2 billion in undrawn credit facilities and obtained $415 million in cash, of which $364 million was used to reduce outstanding short-term borrowings.

We believe we will have the capital resources to fund our planned capital spending program and to meet current working capital requirements through cash flow from operations and our committed credit facilities, assuming our current production outlooks are met. Our cash flow from operations depends on a number of factors, including commodity prices, production/sales levels, refining and marketing margins, operating expenses, taxes, royalties, and US$/Cdn$ exchange rates. If additional capital is required, we believe adequate additional financing will be available in the debt capital markets at commercial terms and rates.

Although benchmark oil prices have continued to strengthen through 2009, we have maintained crude oil hedge contracts through the remainder of the year and into 2010 that provide an element of security to our cash flow from operations. For further details on our derivative hedging programs, see page 20.

Management of debt levels continues to be a priority given our long-term growth plans. We believe a phased and flexible approach to existing and future growth projects should assist us in maintaining our ability to manage project costs and debt levels. At September 30, 2009, our net debt (short-term debt and long-term debt less cash and cash equivalents) was $13.263 billion, compared to $7.226 billion at December 31, 2008. The increase in debt levels resulting from the merger with Petro-Canada caused our net debt/cash flow from operations measure to increase significantly, as the calculation only includes two months of cash flow from operations relating to legacy Petro-Canada operations. Undrawn lines of credit at September 30, 2009 were approximately $5.4 billion.

Subsequent to the end of the third quarter, we reduced our committed bilateral credit facility from $855 million to $330 million, and we increased our commercial paper program from $1.5 billion to $2.5 billion. As well, in October Dominion Bond Rating Service confirmed our A (low) rating with a Stable Trend, and Moody's Investors Service moved our senior unsecured rating to Baa2; outlook stable (from Baa1; under review for potential downgrade).

We are subject to financial and operating covenants related to our public market and bank debt. Failure to meet the terms of one or more of these covenants may constitute an Event of Default as defined in the respective debt agreements, potentially resulting in accelerated repayment of one or more of the debt obligations. We are in compliance with our financial covenant that require consolidated debt to not be more than 60% of our total capitalization. At September 30, 2009, our consolidated debt to total capitalization was 29% (where consolidated debt is short-term debt plus long-term debt, and total capitalization is consolidated debt plus shareholders' equity). We are also in compliance with all operating covenants.

Excluding cash and cash equivalents, short-term debt, the current portion of long-term debt and future income taxes, Suncor had operating working capital of $15 million at the end of the third quarter of 2009, compared to a deficiency of $111 million at the end of the third quarter of 2008.

The preceding paragraphs contain forward-looking information regarding our liquidity and capital resources based on factors and assumptions discussed above and on page 25. Users of this information are cautioned that our actual liquidity and capital resources may vary materially.

Significant Capital Project Update

With the deferral of the company's growth projects and the reduction of capital spending announced in January 2009, construction on the Voyageur upgrader and Firebag in-situ facilities has been wound down and the projects placed into safe mode, pending resumption of expansion work. At this time, construction restart and completion targets for these projects, and start up and completion targets for other expansion projects, have not been determined. For a summary of the projects placed into safe mode, please see page 14 of our 2008 Annual Report.

During the third quarter of 2009, the Steepbank extraction plant was completed on schedule and within the revised budget disclosed in our 2009 second quarter report. The plant began operations in late September, after commissioning, and is expected to result in improved reliability and productivity within our oil sands business beginning in the fourth quarter of 2009.

The Firebag sulphur plant was also completed on schedule and on budget during the third quarter of 2009. The plant is ready to operate and is expected to support sulphur emissions reductions for existing and planned in-situ development.

Development drilling has commenced and installation of subsea infrastructure is underway for the North Amethyst portion of the White Rose Extensions, with the project on schedule to deliver first oil in early 2010. The West White Rose development will be divided into two stages. Stage 1 was approved in Q2 2009, and development drilling and subsea installation of this stage will take place in 2010, with first oil expected in late 2010 or early 2011. Results of Stage 1, combined with ongoing evaluation, will help define the full field development scope.

The Syria Ebla Gas Project remains on plan for first gas delivery in mid-2010 and was 80% complete at the end of the third quarter of 2009. Five wells have been completed and are ready for production. In addition, the 3D seismic acquisition of the Cherrife field was completed at the end of the third quarter of 2009.

Work has now commenced on implementing the projects associated with the new Libya Exploration and Production Sharing Agreements (EPSAs), with a focus on preparing the Amal field development program and initiating the new exploration program. Work on the exploration program is progressing, with three seismic surveys completed during the quarter and another three seismic crews continuing to acquire data in country.

The preceding paragraphs 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.

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

For a list of the additional risk factors that could cause actual timing, amount of the final capital expenditures and expected results to differ materially, please see page 19 of Suncor's 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 25.

Derivative Financial Instruments

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

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

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

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

Commodity and Treasury Hedging Activities

The company has hedged a portion of its forecasted U.S. dollar denominated sales subject to U.S. dollar West Texas Intermediate (WTI) price risk. We continue to hold contracts to sell approximately 105,000 barrels per day (bpd) of production at US$51.00 and options to sell 55,000 bpd at an equivalent WTI floor price of US$60.00 for the remainder of 2009.

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

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

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

We periodically enter into interest rate swap contracts as part of our strategy to manage exposure to interest rates. The interest rate swap contracts involve an exchange of floating rate and fixed rate interest payments between ourselves and investment grade counterparties. The differentials on the exchange of periodic interest payments are recognized as an adjustment to interest expense. Amounts received or paid on settlement will be recorded as part of the related hedged sales transactions.

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

Significant commodity contracts outstanding at September 30, 2009 were as follows:

Crude Oil	Quantity (bpd)	Price (US$/bbl) [1]	Hedge Period
Purchased puts	55 000	60.00	2009
Fixed price	104 391	51.00	2009
Purchased puts	55 000	60.00	2010
Sold puts	54 753	60.00	2010
Collars – floor	50 041	50.00	2010
Collars – cap	49 986	68.06	2010

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

The net earnings impact associated with our commodity and treasury hedging activities in the third quarter of 2009 was a pre-tax gain of $55 million, compared to $68 million in the third quarter of 2008. The earnings impact in the first nine months of 2009 was a pre-tax loss of $897 million, compared to a pre-tax loss of $31 million in the first nine months of 2008.

A reconciliation of changes in accumulated other comprehensive income (AOCI) attributable to derivative hedging activities for the nine month periods ending September 30 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 – $3)	**1**	(7)
Net unrealized hedging losses (gains) at the beginning of the year reclassified to earnings during the period, net of income taxes of $nil (2008 – $2)	**2**	5
AOCI attributable to derivative hedging activities, at September 30, net of income taxes of $5 (2008 – $3)	**16**	11

Energy Trading Activities

In addition to derivative contracts used for hedging activities, Suncor uses physical and financial energy derivatives to earn trading revenues. These energy contracts are comprised of crude oil, natural gas and refined products derivative contracts. The results of these trading activities are reported as energy trading revenues and expenses in the Consolidated Statements of Earnings and Comprehensive Income. The net pre-tax earnings associated with our energy trading activities in the third quarter of 2009 were $35 million (2008 – $85 million). The net pre-tax earnings in the first nine months of 2009 were $34 million (2008 – $100 million).

Fair Value of Derivative Financial Instruments

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

($ millions)	**September 30 2009**	December 31 2008
Derivative financial instruments accounted for as hedges		
Assets	**20**	24
Liabilities	**—**	(13)
Derivative financial instruments not accounted for as hedges		
Assets	**209**	635
Liabilities	**(627)**	(14)
Net derivative financial instruments	**(398)**	632

Risks Associated with Derivative Financial Instruments

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

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

Energy marketing and trading activities are governed by a separate risk management function which reviews and monitors practices and policies and provides independent verification and valuation of these activities.

Risk Factors Affecting Performance

For a description of risk factors that may affect performance, including but not limited to political, environmental, socio-economic, operational, market and other business risk factors, see Suncor's 2008 Annual Information Form and Petro-Canada's 2008 Annual Information Form.

Environmental Regulation and Risk

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

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

Currently in the UK, a review of regulations which may impact the disposal of naturally occurring radioactive material (NORM) is in consultation stage with the government. At this time, no such legislation has been tabled in this jurisdiction and any potential impacts are unknown.

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

In early 2009, a number of frameworks, proposals and directives were issued by the various provincial regulators that oversee oil sands development. These relate to tailings management, water use and land use to name a few. While the financial implications of such directives are yet unknown, Suncor is committed to working with the appropriate regulatory bodies as they develop new policies and to fully comply with all existing and new regulations and directives as they apply to the company's operations. In Suncor's recently released 2009 Report on Sustainability, we announced environmental targets for air emissions, land reclamation and water use. For details on these targets, refer to the Report on Sustainability located at www.suncor.com.

Control Environment

Based on their evaluation as of September 30, 2009, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the United States Securities Exchange Act of 1934 (the Exchange Act)) are effective to ensure that information required to be disclosed by us in reports that we file or submit to Canadian and U.S. securities authorities is recorded, processed, summarized and reported within the time periods specified in Canadian and U.S. securities laws. In addition, as of September 30, 2009, there were no changes in our internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) – 15d-15(f)) that occurred during the three month period ended September 30, 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We will continue to periodically evaluate our disclosure controls and procedures and internal control over financial reporting and will make any modifications from time-to-time as deemed necessary.

Management continues to integrate the acquired company historical internal control over financial reporting with

Suncor's internal control over financial reporting. This integration will lead to changes in these controls in future fiscal periods but management does not yet know whether these changes will materially affect the Company's internal control over financial reporting. Management expects this integration process to be completed during 2010.

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

Change in Accounting Policies

(a) Goodwill and Intangible Assets

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

Change in Consolidated Balance Sheets

($ millions, increase/(decrease))	**As at September 30 2009**	As at December 31 2008
Property, plant and equipment, net	**475**	566
Other assets	**(475)**	(566)

(b) International Financial Reporting Standards

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

In the third quarter of 2009, the company began integration of the legacy Petro-Canada and Suncor's IFRS conversion projects. Key activities included integrating the project plans, reviewing the accounting documentation, aligning the IFRS accounting conclusions, and reviewing of the design of the Information Technology dual reporting solutions.

The IFRS project continues to be on target to meet the changeover date. New and revised IFRS developments will be reviewed throughout the project and changes made as necessary.

Non-GAAP Financial Measures

Certain financial measures referred to in this MD&A, 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, 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 8 of this MD&A for a reconciliation of net earnings to operating earnings.

Suncor provides a detailed numerical reconciliation of ROCE on an annual basis in the company's annual MD&A, which is to be read in conjunction with the company's annual consolidated financial statements. For a summarized narrative reconciliation of ROCE calculated on a September 30, 2009 interim basis, please refer to page 48.

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 includes the impact of fair value changes on both the current and long-term portions of commodity derivatives and stock-based compensation (previously only included the impact on the long-term portions). 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 an integral part of Suncor's September 30, 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 September 30		Nine months ended September 30	
	2009	2008	**2009**	2008
Cash flow from operations ($ millions)	**574**	1 146	**1 670**	3 826
Weighted number of shares outstanding – basic (millions of shares)	**1 247.9**	934.5	**1 061.1**	930.4
Cash flow from operations – basic ($ per share)	**0.46**	1.23	**1.57**	4.11

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 September 30				Nine months ended September 30			
	2009		2008		**2009**		2008	
(unaudited)	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses	**981**		822		**2 977**		2 213	
Less: Natural gas costs, inventory changes, stock-based compensation, and other	**(23)**		(182)		**(236)**		(341)	
Less: Safe mode costs	**(45)**		—		**(260)**		—	
Less: Non-monetary transactions	**(14)**		(25)		**(56)**		(81)	
Less: Syncrude-related operating, selling and general expenses	**(66)**		—		**(66)**		—	
Accretion of asset retirement obligations	**27**		14		**80**		41	
Cash costs	**860**	**30.65**	629	27.80	**2 439**	**30.30**	1 832	30.00
Natural gas	**44**	**1.55**	97	4.30	**164**	**2.05**	347	5.70
Imported bitumen (excluding other reported product purchases)	**2**	**0.05**	42	1.90	**3**	**0.05**	107	1.75
Cash operating costs	**906**	**32.25**	768	34.00	**2 606**	**32.40**	2 286	37.45
Project start-up costs	**12**	**0.45**	8	0.35	**38**	**0.45**	29	0.50
Total cash operating costs	**918**	**32.70**	776	34.35	**2 644**	**32.85**	2 315	37.95
Depreciation, depletion and amortization	**214**	**7.60**	151	6.70	**593**	**7.35**	412	6.75
Total operating costs	**1 132**	**40.30**	927	41.05	**3 237**	**40.20**	2 727	44.70
Production excluding Syncrude (thousands of barrels per day)	**305.3**		245.6		**294.8**		222.6	

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

Oil Sands Operating Costs – In-Situ Bitumen Production Only

	Three months ended September 30				Nine months ended September 30			
	2009		2008		**2009**		2008	
(unaudited)	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses	**113**		82		**307**		251	
Less: Natural gas costs	**(29)**		(42)		**(82)**		(133)	
Less: Safe mode costs	**(16)**		—		**(66)**		—	
Cash costs	**68**	**10.25**	40	10.75	**159**	**10.65**	118	11.75
Natural gas	**29**	**4.30**	42	11.30	**82**	**5.55**	133	13.25
Cash operating costs	**97**	**14.55**	82	22.05	**241**	**16.20**	251	25.00
In-situ start-up costs	**4**	**0.65**	3	0.80	**19**	**1.30**	9	0.90
Total cash operating costs	**101**	**15.20**	85	22.85	**260**	**17.50**	260	25.90
Depreciation, depletion and amortization	**39**	**5.95**	20	5.40	**92**	**6.25**	63	6.30
Total operating costs	**140**	**21.15**	105	28.25	**352**	**23.75**	323	32.20
Production (thousands of barrels per day)	**71.9**		40.4		**54.3**		36.6	

Notice – Forward-Looking Information

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

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

Suncor's outlook includes a production range based on our current expectations, estimates, projections and assumptions. Uncertainties in the estimating process and the impact of future events may cause actual results to differ, in some cases materially, from our estimates. Assumptions are based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be relevant. For a description of assumptions and risk factors specifically related to the 2009 outlook, see page 4 of our third quarter 2009 report to Shareholders.

The risks, uncertainties and other factors that could influence actual results include but are not limited to, market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates; availability of third-party bitumen; success of hedging strategies, maintaining a desirable debt to cash flow ratio; changes in the general economic, market and business conditions; fluctuations in supply and demand for Suncor's products; commodity prices, interest rates and currency exchange rates; Suncor's ability to respond to changing markets and to receive timely regulatory approvals; the successful and timely implementation of capital projects including growth projects and regulatory projects; 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; political, economic and socio-economic risk associated with foreign operations (including OPEC production quotas); 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 the two entities; and incorrect assessments of the values of the other entity. The foregoing important factors are not exhaustive.

Many of these risk factors are discussed in further detail throughout this Management's Discussion and Analysis and in 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 September 30 2009	Three months ended September 30 2008 (restated) (note 2)	Nine months ended September 30 2009	Nine months ended September 30 2008 (restated) (note 2)
Revenues				
Operating revenues	**5 847**	5 598	**11 121**	14 198
Less: Royalties	**(450)**	(301)	**(612)**	(804)
Operating revenues (net of royalties)	**5 397**	5 297	**10 509**	13 394
Energy trading activities (note 5)	**2 608**	3 198	**6 896**	8 267
Interest and other income (note 3f)	**438**	12	**439**	25
	8 443	8 507	**17 844**	21 686
Expenses				
Purchases of crude oil and products	**2 284**	2 640	**4 502**	5 838
Operating, selling and general (note 9)	**1 747**	1 037	**4 283**	2 960
Energy trading activities (note 5)	**2 572**	3 156	**6 857**	8 272
Transportation costs	**133**	53	**260**	153
Depreciation, depletion and amortization	**621**	263	**1 234**	763
Accretion of asset retirement obligations	**45**	16	**103**	48
Exploration	**129**	30	**168**	73
Loss (gain) on disposal of assets	**(10)**	4	**12**	(14)
Project start-up costs	**12**	8	**38**	29
Financing expenses (income) (note 7)	**(348)**	156	**(417)**	241
	7 185	7 363	**17 040**	18 363
Earnings Before Income Taxes	**1 258**	1 144	**804**	3 323
Provisions for (Recovery of) Income Taxes (note 14)				
Current	**449**	192	**653**	406
Future	**(120)**	137	**(538)**	565
	329	329	**115**	971
Net Earnings	**929**	815	**689**	2 352
Net Earnings Per Common Share (dollars), (note 8)				
Basic	**0.74**	0.87	**0.65**	2.53
Diluted	**0.74**	0.86	**0.64**	2.48
Cash dividends	**0.10**	0.05	**0.20**	0.15

Consolidated Statements of Comprehensive Income

(unaudited)

($ millions)	Three months ended September 30 2009	Three months ended September 30 2008	Nine months ended September 30 2009	Nine months ended September 30 2008
Net earnings	**929**	815	**689**	2 352
Other comprehensive income (loss), net of income taxes				
Change in foreign currency translation adjustment	**(186)**	52	**(250)**	93
Gain (loss) on derivative contracts designated as cash flow hedges	**1**	52	**3**	(2)
Comprehensive Income	**744**	919	**442**	2 443

See accompanying notes

Consolidated Balance Sheets

(unaudited)

($ millions)	**September 30 2009** (note 3)	December 31 2008 (restated) (note 2)
Assets		
Current assets		
Cash and cash equivalents	**587**	660
Accounts receivable (note 5)	**4 020**	1 580
Inventories	**2 683**	909
Income taxes receivable	**586**	67
Future income taxes	**362**	21
Total current assets	**8 238**	3 237
Property, plant and equipment, net (note 2)	**57 572**	28 882
Other assets (note 2)	**570**	388
Goodwill (note 3)	**3 221**	21
Future income taxes	**345**	—
Total assets	**69 946**	32 528
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**3**	2
Current portion of long-term debt (note 12)	**21**	18
Accounts payable and accrued liabilities (note 5)	**5 997**	3 326
Income taxes payable	**1 277**	81
Future income taxes	**15**	111
Total current liabilities	**7 313**	3 538
Long-term debt (note 12)	**13 826**	7 866
Accrued liabilities and other (note 5)	**5 473**	1 986
Future income taxes (note 14)	**9 480**	4 615
Shareholders' equity (see below)	**33 854**	14 523
Total liabilities and shareholders' equity	**69 946**	32 528

Shareholders' Equity

	Number (thousands)		Number (thousands)	
Share capital	**1 558 901**	**20 031**	935 524	1 113
Contributed surplus		**508**		288
Accumulated other comprehensive income (loss) (note 13)		**(150)**		97
Retained earnings		**13 465**		13 025
Total shareholders' equity		**33 854**		14 523

See accompanying notes

Consolidated Statements of Cash Flows

(unaudited)

($ millions)	Three months ended September 30 2009	Three months ended September 30 2008	Nine months ended September 30 2009	Nine months ended September 30 2008
Operating Activities				
Net earnings	**929**	815	**689**	2 352
Adjustments for:				
Depreciation, depletion and amortization	**621**	263	**1 234**	763
Future income taxes	**(120)**	137	**(538)**	565
Accretion of asset retirement obligations	**45**	16	**103**	48
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(400)**	173	**(657)**	238
Change in fair value of derivative contracts	**(333)**	(173)	**1 039**	(131)
Loss (gain) on disposal of assets	**(10)**	4	**12**	(14)
Stock-based compensation	**125**	(25)	**228**	14
Gain on effective settlement of pre-existing contract with Petro-Canada (note 3f)	**(438)**	—	**(438)**	—
Other	**61**	(83)	**(127)**	(57)
Exploration expenses	**94**	19	**125**	48
Cash flow from operating activities before changes in non-cash working capital	**574**	1 146	**1 670**	3 826
Decrease (increase) in non-cash working capital related to operating activities (note 15)	**99**	83	**(568)**	(583)
Cash flow from operating activities	**673**	1 229	**1 102**	3 243
Investing Activities				
Capital and exploration expenditures	**(961)**	(1 959)	**(2 690)**	(5 317)
Deferred outlays and other investments	**17**	(3)	**(27)**	(36)
Cash acquired through business combination (net) (note 3)	**248**	—	**248**	—
Proceeds from disposals	**9**	8	**36**	33
Decrease (increase) in non-cash working capital related to investing activities	**(30)**	61	**(708)**	239
Cash flow used in investing activities	**(717)**	(1 893)	**(3 141)**	(5 081)
Net cash deficiency before financing activities	**(44)**	(664)	**(2 039)**	(1 838)
Financing Activities				
Increase (decrease) in short-term debt	**—**	—	**1**	(1)
Net proceeds from issuance of long-term debt	**—**	—	**—**	2 704
Net increase (decrease) in long-term debt	**311**	(152)	**2 209**	(195)
Issuance of common shares under stock option plan	**8**	15	**30**	184
Dividends paid on common shares	**(155)**	(46)	**(249)**	(134)
Cash flow provided by (used in) financing activities	**164**	(183)	**1 991**	2 558
Increase (Decrease) in Cash and Cash Equivalents	**120**	(847)	**(48)**	720
Effect of Foreign Exchange on Cash and Cash Equivalents	**(18)**	16	**(25)**	26
Cash and Cash Equivalents at Beginning of Period	**485**	2 146	**660**	569
Cash and Cash Equivalents at End of Period	**587**	1 315	**587**	1 315

See accompanying notes

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	—	—	—	2 352
Dividends paid on common shares	—	—	—	(134)
Issued for cash under stock option plan	218	(34)	—	—
Issued under dividend reinvestment plan	5	—	—	(5)
Stock-based compensation expense	—	94	—	—
Income tax benefit of stock option deduction in the U.S.	—	9	—	—
Change in accumulated other comprehensive income (loss)	—	—	91	—
At September 30, 2008	1 104	263	(162)	13 287
At December 31, 2008	1 113	288	97	13 025
Net earnings	**—**	**—**	**—**	**689**
Dividends paid on common shares	**—**	**—**	**—**	**(249)**
Issued for cash under stock option plans	**38**	**(8)**	**—**	**—**
Issued under dividend reinvestment plan	**2**	**—**	**—**	**—**
Stock-based compensation expense	**—**	**77**	**—**	**—**
Issued for Petro-Canada acquisition (note 3)	**18 878**	**—**	**—**	**—**
Fair value of Petro-Canada stock options exchanged for Suncor stock options (note 3)	**—**	**147**	**—**	**—**
Income tax benefit of stock option deduction in the U.S.	**—**	**4**	**—**	**—**
Change in accumulated other comprehensive income (loss)	**—**	**—**	**(247)**	**—**
At September 30, 2009	**20 031**	**508**	**(150)**	**13 465**

See accompanying notes

Schedules of Segmented Data

(unaudited)

Three months ended September 30

	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	**1 190**	2 334	**167**	201	**125**	—	**468**	—	**3 893**	3 060	**4**	3	**5 847**	5 598
Less: Royalties	**(219)**	(249)	**(16)**	(52)	**(63)**	—	**(152)**	—	**—**	—	**—**	—	**(450)**	(301)
Operating revenues (net of royalties)	**971**	2 085	**151**	149	**62**	—	**316**	—	**3 893**	3 060	**4**	3	**5 397**	5 297
Energy trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**2 608**	3 198	**2 608**	3 198
Intersegment revenues	**987**	315	**41**	15	**97**	—	**—**	—	**2**	—	**(1 127)**	(330)	**—**	—
Interest and other income	**438**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	12	**438**	12
	2 396	2 400	**192**	164	**159**	—	**316**	—	**3 895**	3 060	**1 485**	2 883	**8 443**	8 507
Expenses														
Purchases of crude oil and products	**16**	175	**—**	—	**16**	—	**—**	—	**3 294**	2 855	**(1 042)**	(390)	**2 284**	2 640
Operating, selling and general	**981**	822	**114**	46	**31**	—	**61**	—	**405**	177	**155**	(8)	**1 747**	1 037
Energy trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**2 572**	3 156	**2 572**	3 156
Transportation costs	**62**	48	**20**	6	**8**	—	**12**	—	**35**	3	**(4)**	(4)	**133**	53
Depreciation, depletion and amortization	**242**	151	**148**	59	**50**	—	**78**	—	**97**	40	**6**	13	**621**	263
Accretion of asset retirement obligations	**30**	14	**7**	2	**1**	—	**7**	—	**—**	—	**—**	—	**45**	16
Exploration	**2**	7	**50**	23	**—**	—	**77**	—	**—**	—	**—**	—	**129**	30
Loss (gain) on disposal of assets	**—**	11	**(5)**	2	**—**	—	**—**	—	**(5)**	(2)	**—**	(7)	**(10)**	4
Project start-up costs	**12**	8	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**12**	8
Financing expenses (income)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(348)**	156	**(348)**	156
	1 345	1 236	**334**	138	**106**	—	**235**	—	**3 826**	3 073	**1 339**	2 916	**7 185**	7 363
Earnings (loss) before income taxes	**1 051**	1 164	**(142)**	26	**53**	—	**81**	—	**69**	(13)	**146**	(33)	**1 258**	1 144
Income taxes	**(313)**	(310)	**31**	(8)	**(14)**	—	**(49)**	—	**(18)**	2	**34**	(13)	**(329)**	(329)
Net earnings (loss)	**738**	854	**(111)**	18	**39**	—	**32**	—	**51**	(11)	**180**	(46)	**929**	815

Schedules of Segmented Data (continued)

(unaudited)

Three months ended September 30

($ millions)	Oil Sands 2009	Oil Sands 2008	Natural Gas 2009	Natural Gas 2008	East Coast Canada 2009	East Coast Canada 2008	International 2009	International 2008	Refining and Marketing 2009	Refining and Marketing 2008	Corporate, Energy Trading and Eliminations 2009	Corporate, Energy Trading and Eliminations 2008	Total 2009	Total 2008
CASH FLOW BEFORE FINANCING ACTIVITIES														
Operating activities														
Net earnings (loss)	**738**	854	**(111)**	18	**39**	—	**32**	—	**51**	(11)	**180**	(46)	**929**	815
Adjustments for:														
Depreciation, depletion and amortization	**242**	151	**148**	59	**50**	—	**78**	—	**97**	40	**6**	13	**621**	263
Future income taxes	**(9)**	149	**(24)**	4	**14**	—	**(17)**	—	**18**	(8)	**(102)**	(8)	**(120)**	137
Accretion of asset retirement obligations	**30**	14	**7**	2	**1**	—	**7**	—	**—**	—	**—**		**45**	16
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(400)**	173	**(400)**	173
Change in fair value of derivative contracts	**(302)**	(64)	**(1)**	(6)	**—**	—	**—**	—	**4**	(7)	**(34)**	(96)	**(333)**	(173)
Loss (gain) on disposal of assets	**—**	11	**(5)**	2	**—**	—	**—**	—	**(5)**	(2)	**—**	(7)	**(10)**	4
Stock-based compensation	**39**	6	**13**	1	**2**	—	**9**	—	**23**	2	**39**	(34)	**125**	(25)
Gain on effective settlement of pre-existing contract with Petro-Canada	**(438)**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(438)**	—
Other	**(58)**	(91)	**(2)**	(1)	**24**	—	**9**	—	**87**	5	**1**	4	**61**	(83)
Exploration expenses	**—**	—	**49**	19	**—**	—	**45**	—	**—**	—	**—**	—	**94**	19
Cash flow from (used in) operating activities before changes in non-cash working capital	**242**	1 030	**74**	98	**130**	—	**163**	—	**275**	19	**(310)**	(1)	**574**	1 146
Decrease (increase) in non-cash working capital related to operating activities	**(465)**	726	**13**	110	**32**	—	**58**	—	**(262)**	(380)	**723**	(373)	**99**	83
Total cash flow from (used in) operating activities	**(223)**	1 756	**87**	208	**162**	—	**221**	—	**13**	(361)	**413**	(374)	**673**	1 229
Investing activities:														
Capital and exploration expenditures	**(594)**	(1 791)	**(64)**	(80)	**(63)**	—	**(147)**	—	**(93)**	(77)	**—**	(11)	**(961)**	(1 959)
Deferred outlays and other investments	**(9)**	(6)	**—**	—	**—**	—	**—**	—	**—**	—	**26**	3	**17**	(3)
Cash acquired through business combination (net)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**248**	—	**248**	—
Proceeds from disposals	**—**	—	**—**	1	**—**	—	**—**	—	**9**	—	**—**	7	**9**	8
Decrease (increase) in investing working capital	**(9)**	69	**(13)**	—	**(1)**	—	**(6)**	—	**(1)**	(1)	**—**	(7)	**(30)**	61
Total cash from (used in) investing activities	**(612)**	(1 728)	**(77)**	(79)	**(64)**	—	**(153)**	—	**(85)**	(78)	**274**	(8)	**(717)**	(1 893)
Net cash surplus (deficiency) before financing activities	**(835)**	28	**10**	129	**98**	—	**68**	—	**(72)**	(439)	**687**	(382)	**(44)**	(664)

Schedules of Segmented Data

(unaudited)

Nine months ended September 30

($ millions)	Oil Sands 2009	Oil Sands 2008	Natural Gas 2009	Natural Gas 2008	East Coast Canada 2009	East Coast Canada 2008	International 2009	International 2008	Refining and Marketing 2009	Refining and Marketing 2008	Corporate, Energy Trading and Eliminations 2009	Corporate, Energy Trading and Eliminations 2008	Total 2009	Total 2008
EARNINGS														
Revenues														
Operating revenues	**2 953**	5 998	**333**	572	**125**	—	**468**	—	**7 229**	7 615	**13**	13	**11 121**	14 198
Less: Royalties	**(365)**	(661)	**(32)**	(143)	**(63)**	—	**(152)**	—	**—**	—	**—**	—	**(612)**	(804)
Operating revenues (net of royalties)	**2 588**	5 337	**301**	429	**62**	—	**316**	—	**7 229**	7 615	**13**	13	**10 509**	13 394
Energy trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**6 896**	8 267	**6 896**	8 267
Intersegment revenues	**1 527**	1 045	**63**	45	**97**	—	**—**	—	**2**	—	**(1 689)**	(1 090)	**—**	—
Interest and other income	**438**	—	**—**	—	**—**	—	**—**	—	**—**	—	**1**	25	**439**	25
	4 553	6 382	**364**	474	**159**	—	**316**	—	**7 231**	7 615	**5 221**	7 215	**17 844**	21 686
Expenses														
Purchases of crude oil and products	**242**	336	**—**	—	**16**	—	**—**	—	**5 801**	6 650	**(1 557)**	(1 148)	**4 502**	5 838
Operating, selling and general	**2 977**	2 213	**197**	128	**31**	—	**61**	—	**761**	547	**256**	72	**4 283**	2 960
Energy trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**6 857**	8 272	**6 857**	8 272
Transportation costs	**178**	140	**31**	13	**8**	—	**12**	—	**44**	11	**(13)**	(11)	**260**	153
Depreciation, depletion and amortization	**622**	412	**258**	169	**50**	—	**78**	—	**208**	148	**18**	34	**1 234**	763
Accretion of asset retirement obligations	**82**	41	**12**	6	**1**	—	**7**	—	**1**	1	**—**	—	**103**	48
Exploration	**8**	16	**83**	57	**—**	—	**77**	—	**—**	—	**—**	—	**168**	73
Loss (gain) on disposal of assets	**17**	13	**(20)**	(22)	**—**	—	**—**	—	**15**	2	**—**	(7)	**12**	(14)
Project start-up costs	**38**	29	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**38**	29
Financing expenses (income)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(417)**	241	**(417)**	241
	4 164	3 200	**561**	351	**106**	—	**235**	—	**6 830**	7 359	**5 144**	7 453	**17 040**	18 363
Earnings (loss) before income taxes	**389**	3 182	**(197)**	123	**53**	—	**81**	—	**401**	256	**77**	(238)	**804**	3 323
Income taxes	**(68)**	(882)	**48**	(34)	**(14)**	—	**(49)**	—	**(126)**	(87)	**94**	32	**(115)**	(971)
Net earnings (loss)	**321**	2 300	**(149)**	89	**39**	—	**32**	—	**275**	169	**171**	(206)	**689**	2 352
As at September 30														
TOTAL ASSETS	**35 505**	23 161	**5 381**	1 807	**4 870**	—	**9 879**	—	**11 132**	5 702	**3 179**	(139)	**69 946**	30 531

Schedules of Segmented Data (continued)

(unaudited)

Nine months ended September 30

($ millions)	Oil Sands		Natural Gas		East Coast Canada		International		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008
CASH FLOW BEFORE FINANCING ACTIVITIES														
Operating activities														
Net earnings (loss)	**321**	2 300	**(149)**	89	**39**	—	**32**	—	**275**	169	**171**	(206)	**689**	2 352
Adjustments for:														
Depreciation, depletion and amortization	**622**	412	**258**	169	**50**	—	**78**	—	**208**	148	**18**	34	**1 234**	763
Future income taxes	**(540)**	515	**(23)**	20	**14**	—	**(17)**	—	**103**	72	**(75)**	(42)	**(538)**	565
Accretion of asset retirement obligations	**82**	41	**12**	6	**1**	—	**7**	—	**1**	1	**—**	—	**103**	48
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(657)**	238	**(657)**	238
Change in fair value of derivative contracts	**988**	(81)	**(1)**	(1)	**—**	—	**—**	—	**(19)**	5	**71**	(54)	**1 039**	(131)
Loss (gain) on disposal of assets	**17**	13	**(20)**	(22)	**—**	—	**—**	—	**15**	2	**—**	(7)	**12**	(14)
Stock-based compensation	**76**	59	**15**	4	**2**	—	**9**	—	**30**	16	**96**	(65)	**228**	14
Gain on effective settlement of pre-existing contract with Petro-Canada	**(438)**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(438)**	—
Other	**(232)**	(73)	**(3)**	(9)	**24**	—	**9**	—	**82**	16	**(7)**	9	**(127)**	(57)
Exploration expenses	**—**	—	**80**	48	**—**	—	**45**	—	**—**	—	**—**	—	**125**	48
Cash flow from (used in) operating activities before changes in non-cash working capital	**896**	3 186	**169**	304	**130**	—	**163**	—	**695**	429	**(383)**	(93)	**1 670**	3 826
Decrease (increase) in operating working capital	**(1 523)**	190	**(2)**	41	**32**	—	**58**	—	**(584)**	(225)	**1 451**	(589)	**(568)**	(583)
Total cash flow from (used in) operating activities	**(627)**	3 376	**167**	345	**162**	—	**221**	—	**111**	204	**1 068**	(682)	**1 102**	3 243
Investing activities:														
Capital and exploration expenditures	**(2 073)**	(4 899)	**(254)**	(246)	**(63)**	—	**(147)**	—	**(153)**	(152)	**—**	(20)	**(2 690)**	(5 317)
Deferred outlays and other investments	**(35)**	(37)	**—**	—	**—**	—	**—**	—	**—**	—	**8**	1	**(27)**	(36)
Cash acquired through business combination (net)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**248**	—	**248**	—
Proceeds from disposals	**—**	—	**27**	26	**—**	—	**—**	—	**9**	—	**—**	7	**36**	33
Decrease (increase) in investing working capital	**(687)**	260	**(13)**	—	**(1)**	—	**(6)**	—	**(1)**	(14)	**—**	(7)	**(708)**	239
Total cash from (used in) investing activities	**(2 795)**	(4 676)	**(240)**	(220)	**(64)**	—	**(153)**	—	**(145)**	(166)	**256**	(19)	**(3 141)**	(5 081)
Net cash surplus (deficiency) before financing activities	**(3 422)**	(1 300)	**(73)**	125	**98**	—	**68**	—	**(34)**	38	**1 324**	(701)	**(2 039)**	(1 838)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

1. ACCOUNTING POLICIES

These interim consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and follow the same accounting policies and methods of computation as, and should be read in conjunction with, the most recent annual financial statements, except for the accounting policy change as described in note 2, Change in Accounting Policies. Certain information and disclosures normally required to be included in notes to the annual consolidated financial statements have been condensed or omitted.

In the opinion of management, these interim consolidated financial statements contain all adjustments of a normal and recurring nature necessary to present fairly Suncor Energy Inc.'s (Suncor) financial position at September 30, 2009 and the results of its operations and cash flows for the three and nine month periods ended September 30, 2009 and 2008.

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

2. CHANGE IN ACCOUNTING POLICIES

Goodwill and Intangible Assets

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

Change in Consolidated Balance Sheets

($ millions, increase/(decrease))	**As at September 30 2009**	As at December 31 2008
Property, plant and equipment, net	**475**	566
Other assets	**(475)**	(566)

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 fair values were assigned to the net assets of Petro-Canada as at August 1, 2009:

($ millions)	
Current assets	4,645
Property, plant and equipment	27,550
Other assets	537
Total assets	32,732
Current liabilities	3,762
Long-term debt	4,410
Accrued liabilities and other	3,439
Future income taxes	4,690
Total liabilities	16,301
Net assets purchased	16,431
Goodwill	3,199
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. The company is in the process of finalizing the allocation of goodwill on acquisition to its operating segments. In the Schedule of Segmented Data, goodwill on acquisition has been included in total assets for the Corporate, Energy Trading and Eliminations 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 (EIC 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 U.K., 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.

The Corporate, Energy Trading and Eliminations segment 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

(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 September 30, 2009, the carrying value of our fixed-term debt accounted for under the amortized cost method was $10.3 billion (December 31, 2008 – $6.7 billion) and the fair value was $10.8 billion (December 31, 2008 – $5.4 billion).

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

Fair Value Hedges

At September 30, 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 nine month periods ended September 30, 2009 and September 30, 2008.

There was no earnings impact associated with hedge ineffectiveness on derivative contracts to hedge risks specific to individual transactions during the three month period ended September 30, 2009 (2008 – loss of $1 million, net of income taxes of $1 million). During the nine month period ended September 30, 2009, the earnings impact was a gain of $2 million, net of income taxes of $1 million (2008 – loss of $4 million, net of income taxes of $2 million).

Cash Flow Hedges

At September 30, 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 nine month periods ended September 30, 2009 and September 30, 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)	**September 30 2009**	December 31 2008
Revenue hedge swaps and collars	**1**	(2)
Fixed to floating interest rate swaps	**17**	24
Specific hedges of individual transactions	**2**	(11)
Fair value of outstanding hedging derivative financial instruments	**20**	11

Accumulated Other Comprehensive Income (AOCI)

A reconciliation of changes in AOCI attributable to derivative hedging activities for the nine month periods ending September 30 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 – $3)	**1**	(7)
Net unrealized hedging losses at the beginning of the year reclassified to earnings during the period, net of income taxes of $nil (2008 – $2)	**2**	5
AOCI attributable to derivative hedging activities, at September 30, net of income taxes of $5 (2008 – $3)	**16**	11

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

The company also periodically enters into derivative financial instruments such as options, basis swaps, and heat rate swaps that either do not qualify for hedge accounting treatment or that the company has not elected to document as part of a qualifying hedge relationship. The earnings impact associated with these contracts for the three month period ended September 30, 2009, was a gain of $43 million, net of income taxes of $15 million (2008 – a gain of $54 million, net of income taxes of $22 million). During the nine month period ended September 30, 2009, the earnings impact was a loss of $658 million, net of income taxes of $232 million (2008 – a loss of $6 million, net of income taxes of $2 million).

Significant contracts outstanding at September 30, 2009 were as follows:

Crude oil	Quantity (bpd)	Average Price [1] (US$/bbl)	Hedge Period
Purchased puts [2]	55 000	60.00	2009
Fixed price	104 391	51.00	2009
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$59 million.

(3) Premium received was US$213 million.

(d) Energy Trading Activities

In addition to the financial derivatives used for hedging activities, the company uses physical and financial energy contracts, including swaps, forwards and options to earn trading revenues. Physical energy trading contracts involve activities intended to enhance prices and satisfy physical deliveries to customers. Net pretax earnings for the three and nine month periods ended September 30, before intersegment eliminations, were as follows:

Earnings (Loss) Before Income Taxes

($ millions)	Three months ended September 30 2009	2008	Nine months ended September 30 2009	2008
Physical energy contracts trading activity	**42**	92	**51**	103
Financial energy contracts trading activity	**(3)**	(6)	**(8)**	3
General and administrative costs	**(4)**	(1)	**(9)**	(6)
Total	**35**	85	**34**	100

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

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

($ millions)	**September 30 2009**	December 31 2008
Derivative financial instrument assets (1)	**209**	635
Derivative financial instrument liabilities (2)	**(627)**	(14)
Net assets (liabilities)	**(418)**	621

(1) As at September 30, 2009, $168 million is recorded in accounts receivable (December 31, 2008 – $376 million) and $41 million is recorded in other assets (December 31, 2008 – $259 million) in the Consolidated Balance Sheets.

(2) As at September 30, 2009, $517 million is recorded in accounts payable and accrued liabilities (December 31, 2008 – $14 million) and $110 million is recorded in accrued liabilities and other in the Consolidated Balance Sheets.

Change in fair value of net assets

($ millions)	**2009**
Fair value of contracts outstanding at December 31, 2008	621
Fair value of contracts realized during the period	**177**
Fair value of contracts entered into during the period	**(854)**
Changes in values attributable to market price and other market changes during the period	**(362)**
Fair value of contracts outstanding at September 30, 2009	**(418)**

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 September 30, 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 September 30, 2009:

Financial Instrument Sensitivity Analysis

($ millions)	September 30, 2009 (1)	Change	Net Earnings	Other Comprehensive Income
Crude Oil	US$76.37/barrel			
Price increase		US$1.00/barrel	(20)	—
Price decrease		US$1.00/barrel	20	—
Natural Gas	US$5.91/mcf			
Price increase		US$0.10/mcf	—	—
Price decrease		US$0.10/mcf	—	—

(1) Prices represent the average of the forward strip prices at September 30, 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 and total debt to total debt plus shareholders' equity.

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

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

The company's strategy during the third 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 September 30, ($ millions)	Capital Measure Target	2009	2008
Components of ratios			
Short-term debt		**3**	2
Current portion of long-term debt		**21**	5
Long-term debt		**13 826**	6 568
Total debt		**13 850**	6 575
Cash and equivalents		**587**	1 315
Net debt		**13 263**	5 260
Shareholders' equity		**33 854**	14 492
Total capitalization (total debt + shareholders' equity)		**47 704**	21 067
Cash flow from operations (trailing twelve months)		**1 901**	5 011
Net debt/cash flow from operations	< 2.0 times	**7.0**	1.0
Total debt/total debt plus shareholders' equity		**29%**	31%

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 two 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)

($ millions)	Three months ended September 30 2009	2008	Nine months ended September 30 2009	2008
Interest on debt	**156**	101	**391**	242
Capitalized interest	**(22)**	(101)	**(94)**	(242)
Net interest expense	**134**	—	**297**	—
Foreign exchange (gain) loss on long-term debt	**(400)**	173	**(657)**	238
Other foreign exchange (gain) loss	**(82)**	(17)	**(57)**	3
Total financing expenses (income)	**(348)**	156	**(417)**	241

8. RECONCILIATION OF BASIC AND DILUTED EARNINGS PER COMMON SHARE

($ millions)	Three months ended September 30 2009	2008	Nine months ended September 30 2009	2008
Net earnings	**929**	815	**689**	2 352
(millions of common shares)				
Weighted-average number of common shares	**1 248**	935	**1 061**	930
Dilutive securities:				
Options issued under stock-based compensation plans	**13**	18	**13**	18
Weighted-average number of diluted common shares	**1 261**	953	**1 074**	948
(dollars per common share)				
Basic earnings per share [(a)]	**0.74**	0.87	**0.65**	2.53
Diluted earnings per share [(b)]	**0.74**	0.86	**0.64**	2.48

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)	Common Shares 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	**2 147**	**38**
Issued under dividend reinvestment plan	**88**	**2**
Balance as at September 30, 2009	**1 558 901**	**20 031**

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. The company granted 243,000 options in the third quarter of 2009, for a total of 1,204,000 options granted in the nine months ended September 30, 2009 (730,000 options granted during the third quarter of 2008; 1,786,000 options granted during the nine months ended September 30, 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. The company did not grant options under this plan in the third quarter of 2009. A total of 711,000 options were granted in the nine months ended September 30, 2009 (42,000 options granted during the third quarter of 2008; 870,000 granted in the nine months ended September 30, 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. Under this plan, the company granted 2,000 common share options in the third quarter of 2009, for a total of 571,000 options granted in the nine months ended September 30, 2009 (11,000 options granted during the third quarter of 2008; 2,373,000 granted in the nine months ended September 30, 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 September 30, 2009, there were 28.9 million Adjusted Options outstanding with a weighted-average exercise price per share of $28.01.

(v) Suncor Energy Inc. Stock Options

The company granted 4,000 options under this plan, which came into effect on August 1, 2009. This plan 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 September 30, 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	3 030	2	9.93	3 030	9.93
13.00 – 17.99	14 565	3	14.20	14 565	14.20
18.00 – 29.99	15 674	4	22.34	11 243	22.95
30.00 – 44.99	18 171	5	38.90	11 167	39.69
45.00 – 49.99	19 935	5	47.35	4 708	46.57
50.00 – 72.68	2 409	5	55.11	100	53.51
Total	73 784	4	32.12	44 813	25.95

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 September 30		Nine months ended September 30	
	2009	2008	**2009**	2008
Quarterly dividend per share*	**$0.10**	$0.05	**$0.07**	$0.05
Risk-free interest rate	**2.67%**	3.08%	**2.31%**	3.44%
Expected life	**4 years**	5 years	**5 years**	6 years
Expected volatility	**54%**	30%	**47%**	29%
Weighted-average fair value per option	**$11.11**	$12.89	**$10.28**	$14.73

* 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 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 September 30, 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	6 329	6	19.45	—	—
25.01 – 35.00	3 726	4	34.31	1 768	34.33
35.01 – 40.00	4 406	5	36.84	1 125	36.86
40.01 – 46.13	149	5	43.79	68	43.60
Total	14 610	6	28.73	2 961	35.50

(c) Performance Share Units (PSUs)

In the third quarter of 2009, the company issued 4,000 PSUs (2008 – 2,000). For the nine months ended September 30, 2009, the company issued 1,149,000 PSUs (2008 – 782,000). 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 third quarter of 2009, the company issued 1,034,000 RSUs (2008 – 49,000). For the nine months ended September 30, 2009, the company issued 2,649,000 RSUs (2008 – 1,025,000). 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 third quarter of 2009, the company issued 73,000 DSUs (2008 – 25,000). For the nine months ended September 30, 2009, the company issued 86,000 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 September 30		Nine months ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Stock option plans	**65**	25	**116**	94
Adjusted SARs	**25**	—	**25**	—
Performance share units (PSUs)	**9**	(13)	**19**	(3)
Restricted share units (RSUs)	**32**	1	**57**	10
Deferred share units (DSUs)	**7**	(31)	**30**	(13)
Total stock based compensation expense (recovery)	**138**	(18)	**247**	88

10. EMPLOYEE FUTURE BENEFITS LIABILITY

The following is the status of the net periodic benefit cost for the three and nine months ended September 30:

	Pension Benefits			
	Three months ended September 30		Nine months ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Current service costs	**19**	14	**49**	42
Interest costs	**31**	12	**57**	36
Expected return on plan assets	**(24)**	(11)	**(44)**	(33)
Amortization of net actuarial loss	**5**	6	**15**	17
Net periodic benefit cost	**31**	21	**77**	62

	Other Post-Retirement Benefits			
	Three months ended September 30		Nine months ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Current service costs	**2**	1	**5**	3
Interest costs	**4**	2	**9**	7
Amortization of net actuarial loss	**—**	1	**—**	2
Net periodic benefit cost	**6**	4	**14**	12

11. SUPPLEMENTAL INFORMATION

	Three months ended September 30		Nine months ended September 30	
($ millions)	**2009**	2008	**2009**	2008
Interest paid	**63**	54	**297**	178
Income taxes paid	**521**	103	**676**	507

12. LONG-TERM DEBT AND CREDIT FACILITIES

($ millions)	September 30 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)	**804**	918
6.80% Notes, denominated in U.S. dollars, due in 2038 (US$900)	**996**	—
6.50% Notes, denominated in U.S. dollars, due in 2038 (US$1150)	**1 233**	1 408
5.95% Notes, denominated in U.S. dollars, due in 2035 (US$600)	**592**	—
5.95% Notes, denominated in U.S. dollars, due in 2034 (US$500)	**536**	612
5.35% Notes, denominated in U.S. dollars, due in 2033 (US$300)	**272**	—
7.15% Notes, denominated in U.S. dollars, due in 2032 (US$500)	**536**	612
6.10% Notes, denominated in U.S. dollars, due in 2018 (US$1250)	**1 341**	1 531
6.05% Notes, denominated in U.S. dollars, due in 2018 (US$600)	**659**	—
5.00% Notes, denominated in U.S. dollars, due in 2014 (US$400)	**440**	—
4.00% Notes, denominated in U.S. dollars, due in 2013 (US$300)	**320**	—
7.00% Debentures, due in 2028 (US$250)	**278**	—
7.875% Debentures, due in 2026 (US$275)	**334**	—
9.25% Debentures, due in 2021 (US$300)	**414**	—
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
	10 555	6 881
Revolving-term debt, with interest at variable rates		
Commercial paper and bankers' acceptances	**3 111**	934
Total unsecured long-term debt	**13 666**	7 815
Secured long-term debt	**13**	13
Capital leases	**214**	103
Fair value of interest swaps	**17**	25
Deferred financing costs	**(63)**	(72)
	13 847	7 884
Current portion of long-term debt		
Capital leases	**(12)**	(9)
Fair value of interest swaps	**(9)**	(9)
Total current portion of long-term debt	**(21)**	(18)
Total long-term debt	**13 826**	7 866

At September 30, 2009, undrawn lines of credit were $5,421 million, as follows:

($ millions)	2009
Facility that is fully revolving for 364 days, has a term period of one year and expires in 2010	**855**
Facility that is fully revolving for a period of four years and expires in 2013	**214**
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	**778**
Total available credit facilities	**9 167**
Credit facilities supporting outstanding commercial paper and bankers' acceptances	**3 111**
Credit facilities supporting standby letters of credit	**635**
Total undrawn credit facilities	**5 421**

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.

13. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

($ millions)	**September 30 2009**	December 31 2008
Unrealized foreign currency translation gain (loss)	**(166)**	84
Unrealized gains on derivative hedging activities	**16**	13
Total	**(150)**	97

14. INCOME TAXES

($ millions)	Three months ended September 30 **2009**	2008	Nine months ended September 30 **2009**	2008
Provision for (recovery of) income taxes:				
Current:				
Canada	**380**	172	**573**	380
United States	**3**	20	**14**	26
Libya	**35**	—	**35**	—
Netherlands	**12**	—	**12**	—
United Kingdom	**27**	—	**27**	—
Other	**(8)**	—	**(8)**	—
Total current	**449**	192	**653**	406
Future	**(120)**	137	**(538)**	565
Total	**329**	329	**115**	971

The merger of Suncor Energy Inc. and Petro-Canada resulted in a deemed year end for income tax purposes for both companies effective July 31, 2009. This deemed year end generated an increase in income taxes payable as well as an acceleration of the tax payments. The tax payments that would ordinarily have been payable in monthly installments over the August to December period were due and payable at September 30, 2009.

In the third quarter of 2009, the provision for future income tax increased by $152 million due in part to the merger with Petro-Canada. The combined provincial allocation of both entities caused an increase to the future income tax rate, the impact of which is recorded in net earnings and is allocated to the segments as follows: Oil Sands – $140 million, Natural Gas – $9 million, Corporate, Energy Trading and Eliminations – $3 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:

($ millions)	Three months ended September 30 **2009(1)**	2008	Nine months ended September 30 **2009(1)**	2008
Operating activities				
Accounts receivable	**429**	135	**68**	(248)
Inventories	**5**	255	**(376)**	(337)
Accounts payable and accrued liabilities	**(537)**	(366)	**(221)**	127
Taxes payable/receivable	**202**	59	**(39)**	(125)
	99	83	**(568)**	(583)

(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.

Highlights

(unaudited)

	2009	2008
Cash Flow From Operations		
(dollars per common share – basic)		
For the three months ended September 30		
Cash flow from operations (1)	**0.46**	1.23
For the nine months ended September 30		
Cash flow from operations (1)	**1.57**	4.11
Ratios		
For the twelve months ended September 30		
Return on capital employed (%) (2)	**3.7**	28.7
Return on capital employed (%) (3)	**2.6**	21.0
Net debt to cash flow from operations (times) (4)	**7.0**	1.0
Interest coverage on long-term debt (times)		
Net earnings (5)	**1.9**	14.2
Cash flow from operations (6)	**5.9**	18.3
As at September 30		
Debt to debt plus shareholders' equity (%) (7)	**29.0**	31.2
Common Share Information		
As at September 30		
Share price at end of trading		
Toronto Stock Exchange – Cdn$	**37.40**	44.00
New York Stock Exchange – US$	**34.56**	42.14
Common share options outstanding (thousands)	**73 784**	46 829
For the nine months ended September 30		
Average number outstanding, weighted monthly (thousands)	**1 061 074**	930 393

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 – $672 million; 2008 – $3,500 million) after adjustment to add back after-tax financing expense (2009 – $198 million; 2008 – $105 million) divided by average capital employed (2009 – $18,107 million; 2008 – $12,196 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 – $26,246 million; 2008 – $16,703 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 two months of cash flow from operations relating to legacy Petro-Canada operations.

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

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

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

Quarterly Operating Summary

(unaudited)

	Three months ended					Nine months ended		Twelve months ended
	Sept 30	June 30	Mar 31	Dec 31	Sept 30	**Sept 30**	Sept 30	Dec 31
	2009	2009	2009	2008	2008	**2009**	2008	2008
OIL SANDS (excluding Syncrude)								
Production [1], [a]								
Total production	**305.3**	301.0	278.0	243.8	245.6	**294.8**	222.6	228.0
Firebag[k]	**54.3**	48.3	42.4	39.7	40.4	**48.4**	36.6	37.4
MacKay River[k]	**17.6**	—	—	—	—	**5.9**	—	—
Sales [a]								
Light sweet crude oil	**89.6**	99.4	108.8	95.7	48.1	**99.2**	70.7	77.0
Diesel	**36.9**	25.3	22.8	19.1	10.9	**28.4**	20	19.8
Light sour crude oil	**146.8**	150.5	102.7	144.2	157.4	**133.5**	123.4	128.7
Bitumen	**14.3**	10.5	9.1	3.1	2.6	**11.3**	1.0	1.5
Total sales	**287.6**	285.7	243.4	262.1	219.0	**272.4**	215.1	227.0
Average sales price [2], [b]								
Light sweet crude oil *	**71.99**	65.83	54.64	63.69	125.70	**63.68**	114.54	98.66
Other (diesel, light sour crude oil and bitumen) *	**67.51**	62.71	48.80	59.77	114.74	**61.01**	108.82	95.14
Total *	**68.91**	63.79	52.78	61.20	117.14	**61.98**	110.70	96.33
Total	**61.70**	59.00	59.14	61.53	116.32	**60.00**	110.04	95.96

Production from MacKay River was 26.5 thousands of barrels of bitumen per day for the two months ended September 30, 2009. Our proportionate share of production from the Syncrude joint venture was 37.4 thousands of barrels per day, with an average sales price of $75.17 per barrel, for the two months ended September 30, 2009.

Cash operating costs and Total operating costs – Total operations (excluding Syncrude) [c]								
Cash costs	**30.65**	29.65	30.65	35.35	27.80	**30.30**	30.00	31.45
Natural gas	**1.55**	1.65	3.00	4.05	4.30	**2.05**	5.70	5.25
Imported bitumen	**0.05**	—	0.05	1.90	1.90	**0.05**	1.75	1.80
Cash operating costs [3]	**32.25**	31.30	33.70	41.30	34.00	**32.40**	37.45	38.50
Project start-up costs	**0.45**	0.35	0.65	0.30	0.35	**0.45**	0.50	0.40
Total cash operating costs [4]	**32.70**	31.65	34.35	41.60	34.35	**32.85**	37.95	38.90
Depreciation, depletion and amortization	**7.60**	7.20	7.30	7.50	6.70	**7.35**	6.75	6.95
Total operating costs [5]	**40.30**	38.85	41.65	49.10	41.05	**40.20**	44.70	45.85
Cash operating costs and Total operating costs – In-situ bitumen production only [c]								
Cash costs	**10.25**	11.15	10.50	16.55	10.75	**10.65**	11.75	13.00
Natural gas	**4.30**	5.25	7.90	9.65	11.30	**5.55**	13.25	12.30
Cash operating costs [6]	**14.55**	16.40	18.40	26.20	22.05	**16.20**	25.00	25.30
In-situ (Firebag) start-up costs	**0.65**	1.50	3.35	—	0.80	**1.30**	0.90	0.65
Total cash operating costs [7]	**15.20**	17.90	21.75	26.20	22.85	**17.50**	25.90	25.95
Depreciation, depletion and amortization	**5.95**	6.00	7.10	6.55	5.40	**6.25**	6.30	6.35
Total operating costs [8]	**21.15**	23.90	28.85	32.75	28.25	**23.75**	32.20	32.30
Ending capital employed excluding major projects in progress [i]	**14 833**	10 008	10 610	9 352	9 035			
(for the twelve months ended)								
Return on capital employed [j]	**8.4**	11.1	22.9	35.5	46.0			
Return on capital employed [j]**	**4.9**	6.5	13.9	21.8	28.6			

Quarterly Operating Summary (continued)

(unaudited)

	Two months ended	Three months ended					Nine months ended		Twelve months ended
	Sept 30 2009	**Sept 30 2009**	June 30 2009	Mar 31 2009	Dec 31 2008	Sept 30 2008	**Sept 30 2009**	Sept 30 2008	Dec 31 2008
NATURAL GAS									
Gross production									
Natural gas[d]									
Western Canada	**622**	**477**	192	200	195	197	**290**	204	202
U.S. Rockies	**60**	**40**	—	—	—	—	**14**	—	—
Natural gas liquids and crude oil[a]									
Western Canada	**11.3**	**8.3**	3.2	3.1	3.1	2.6	**4.9**	3.1	3.1
U.S. Rockies	**3.6**	**2.4**	—	—	—	—	**0.8**	—	—
Total gross production[f]									
Western Canada	**690**	**527**	211	219	213	213	**319**	223	220
U.S. Rockies	**82**	**54**	—	—	—	—	**19**	—	—
Average sales price[2]									
Natural gas[g]									
Western Canada	**2.73**	**2.79**	3.56	5.63	6.90	9.10	**3.48**	8.66	8.23
U.S. Rockies	**3.01**	**3.01**	—	—	—	—	**3.01**	—	—
Natural gas[g] *									
Western Canada	**2.71**	**2.77**	3.52	5.61	6.84	9.14	**3.46**	8.70	8.25
U.S. Rockies	**3.01**	**3.01**	—	—	—	—	**3.01**	—	—
Natural gas liquids and crude oil[b]									
Western Canada	**54.20**	**53.28**	41.39	39.03	39.31	96.88	**47.70**	81.37	70.89
U.S. Rockies	**67.08**	**67.08**	—	—	—	—	**67.08**	—	—
Ending capital employed[i]		**3 632**	1 200	1 195	1 152	1 120			
(for the twelve months ended)									
Return on capital employed[j]		**(9.6)**	(1.7)	5.0	7.7	10.3			

Quarterly Operating Summary (continued)

(unaudited)

	Two months ended	Three months ended					Nine months ended		Twelve months ended
	Sept 30 2009	**Sept 30 2009**	June 30 2009	Mar 31 2009	Dec 31 2008	Sept 30 2008	**Sept 30 2009**	Sept 30 2008	Dec 31 2008
EAST COAST CANADA									
Production [(a)]									
Terra Nova	**16.0**	**—**	—	—	—	—	**—**	—	—
Hibernia	**28.5**	**—**	—	—	—	—	**—**	—	—
White Rose	**5.1**	**—**	—	—	—	—	**—**	—	—
Total production	**49.6**	**—**	—	—	—	—	**—**	—	—
Average sales price	**75.22**	**—**	—	—	—	—	**—**	—	—
Ending capital employed [(i)]	**2 050**	**—**	—	—	—	—			
(for the twelve months ended)									
Return on capital employed [(j)]	**12.2**	**—**	—	—	—	—			
Return on capital employed [(j)**]	**7.4**	**—**	—	—	—	—			
INTERNATIONAL									
Production [(e)]									
North Sea									
Buzzard	**29.4**	**—**	—	—	—	—	**—**	—	—
Other U.K.	**11.4**	**—**	—	—	—	—	**—**	—	—
The Netherlands sector of the North Sea	**13.8**	**—**	—	—	—	—	**—**	—	—
Total North Sea	**54.6**	**—**	—	—	—	—	**—**	—	—
Other International									
Libya	**42.7**	**—**	—	—	—	—	**—**	—	—
Trinidad & Tobago	**11.3**	**—**	—	—	—	—	**—**	—	—
Total Other International	**54.0**	**—**	—	—	—	—	**—**	—	—
Total production	**108.6**	**—**	—	—	—	—	**—**	—	—
Average sales price – North Sea [(b)]	**68.67**	**—**	—	—	—	—	**—**	—	—
Average sales price – Other International [(l)]	**62.40**	**—**	—	—	—	—	**—**	—	—
Ending capital employed [(i)]	**2 230**	**—**	—	—	—	—			
(for the twelve months ended)									
Return on capital employed [(j)]	**9.3**	**—**	—	—	—	—			
Return on capital employed [(j)**]	**4.8**	**—**	—	—	—	—			

Quarterly Operating Summary (continued)

(unaudited)

	Two months ended	Three months ended					Nine months ended		Twelve months ended
	Sept 30 2009	**Sept 30 2009**	June 30 2009	Mar 31 2009	Dec 31 2008	Sept 30 2008	**Sept 30 2009**	Sept 30 2008	Dec 31 2008
REFINING AND MARKETING									
Eastern North America									
Refined product sales (h)									
Transportation fuels									
Gasoline – retail	**16.8**	**12.5**	4.0	3.8	3.9	3.8	**6.8**	3.9	3.9
– other	**6.2**	**5.8**	4.7	4.4	5.0	4.3	**4.9**	4.0	4.0
Distillate	**12.6**	**10.3**	5.4	5.1	5.4	5.2	**7.0**	5.2	5.2
Total transportation fuel sales	**35.6**	**28.6**	14.1	13.3	14.3	13.3	**18.7**	13.1	13.1
Petrochemicals	**2.3**	**1.7**	1.0	1.0	1.0	1.0	**1.2**	0.8	0.8
Asphalt	**3.3**	**2.4**	0.7	0.8	0.5	0.6	**1.3**	0.6	0.6
Other	**3.8**	**3.0**	1.0	0.5	0.5	1.2	**1.6**	1.0	1.0
Total refined product sales	**45.0**	**35.7**	16.8	15.6	16.3	16.1	**22.8**	15.5	15.5
Crude oil supply and refining									
Processed at refineries (h)	**31.8**	**25.5**	11.8	11.3	11.2	11.6	**16.2**	11.0	11.0
Utilization of refining capacity (j)	**93**	**94**	87	84	101	104	**90**	99	99
Western North America									
Refined product sales (h)									
Transportation fuels									
Gasoline – retail	**5.3**	**3.8**	0.6	0.7	0.7	0.7	**1.7**	0.7	0.7
– other	**14.3**	**12.3**	8.3	7.5	7.1	7.2	**9.4**	7.3	7.3
Distillate	**15.2**	**11.8**	5.0	5.4	5.5	5.4	**7.4**	5.6	5.6
Total transportation fuel sales	**34.8**	**27.9**	13.9	13.6	13.3	13.3	**18.5**	13.6	13.6
Asphalt	**1.6**	**1.7**	1.4	1.2	1.0	1.3	**1.4**	1.3	1.2
Other	**6.1**	**4.6**	1.8	1.0	0.9	1.3	**2.5**	1.3	1.2
Total refined product sales	**42.5**	**34.2**	17.1	15.8	15.2	15.9	**22.4**	16.2	16.0
Crude oil supply and refining									
Processed at refineries (h)	**33.7**	**27.8**	15.6	14.2	13.6	13.5	**19.3**	13.7	13.7
Utilization of refining capacity (j)	**97**	**100**	106	96	95	95	**101**	96	96
Ending capital employed excluding major projects in progress (i)		**8 300**	3 224	2 985	2 974	3 289			
(for the twelve months ended)									
Return on capital employed (j)		**2.5**	3.0	3.7	1.8	9.3			
Return on capital employed (j) **		**2.5**	3.0	3.7	1.8	9.0			

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Nine months ended		Twelve months ended
	Sept 30 2009	June 30 2009	Mar 31 2009	Dec 31 2008	Sept 30 2008	**Sept 30 2009**	Sept 30 2008	Dec 31 2008
NETBACKS								
Natural Gas [g]								
Western Canada								
Average price realized	**3.28**	3.51	5.02	6.35	10.25	**3.72**	9.37	8.64
Royalties	**(0.24)**	0.33	(1.14)	(1.60)	(2.70)	**(0.32)**	(2.35)	(2.17)
Operating costs	**(1.91)**	(1.71)	(1.65)	(1.46)	(1.86)	**(1.81)**	(1.64)	(1.60)
Operating netback	**1.13**	2.13	2.23	3.29	5.69	**1.59**	5.38	4.87
Depreciation, depletion and amortization	**(2.73)**	(2.92)	(2.97)	(2.98)	(3.08)	**(2.83)**	(2.87)	(2.89)
Administrative expenses and other	**(1.12)**	(1.26)	(0.05)	(0.59)	(1.23)	**(0.90)**	(0.48)	(0.52)
Earnings before income taxes	**(2.72)**	(2.05)	(0.79)	(0.28)	1.38	**(2.14)**	2.03	1.46
U.S. Rockies								
Average price realized	**5.17**	—	—	—	—	**5.17**	—	—
Royalties	**(0.82)**	—	—	—	—	**(0.82)**	—	—
Operating costs	**(1.79)**	—	—	—	—	**(1.79)**	—	—
Operating netback	**2.56**	—	—	—	—	**2.56**	—	—
Depreciation, depletion and amortization	**(3.20)**	—	—	—	—	**(3.20)**	—	—
Administrative expenses and other	**(0.45)**	—	—	—	—	**(0.45)**	—	—
Earnings before income taxes	**(1.09)**	—	—	—	—	**(1.09)**	—	—
Total Natural Gas								
Average price realized	**3.45**	3.51	5.02	6.35	10.25	**3.80**	9.37	8.64
Royalties	**(0.29)**	0.33	(1.14)	(1.60)	(2.70)	**(0.35)**	(2.35)	(2.17)
Operating costs	**(1.89)**	(1.71)	(1.65)	(1.46)	(1.86)	**(1.81)**	(1.64)	(1.60)
Operating netback	**1.27**	2.13	2.23	3.29	5.69	**1.64**	5.38	4.87
Depreciation, depletion and amortization	**(2.78)**	(2.92)	(2.97)	(2.98)	(3.08)	**(2.85)**	(2.87)	(2.89)
Administrative expenses and other	**(1.06)**	(1.26)	(0.05)	(0.59)	(1.23)	**(0.87)**	(0.48)	(0.52)
Earnings before income taxes	**(2.57)**	(2.05)	(0.79)	(0.28)	1.38	**(2.08)**	2.03	1.46
East Coast Canada [b]								
Average price realized	**77.85**	—	—	—	—	**77.85**	—	—
Royalties	**(21.02)**	—	—	—	—	**(21.02)**	—	—
Operating costs	**(13.36)**	—	—	—	—	**(13.36)**	—	—
Operating netback	**43.47**	—	—	—	—	**43.47**	—	—
Depreciation, depletion and amortization	**(17.48)**	—	—	—	—	**(17.48)**	—	—
Administrative expenses and other	**(0.52)**	—	—	—	—	**(0.52)**	—	—
Earnings before income taxes	**25.47**	—	—	—	—	**25.47**	—	—

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Nine months ended		Twelve months ended
	Sept 30 2009	June 30 2009	Mar 31 2009	Dec 31 2008	Sept 30 2008	**Sept 30 2009**	Sept 30 2008	Dec 31 2008
International								
North Sea (b)								
Gross price	**72.06**	—	—	—	—	**72.06**	—	—
Operating costs	**(14.04)**	—	—	—	—	**(14.04)**	—	—
Operating netback	**58.02**	—	—	—	—	**58.02**	—	—
Depreciation, depletion and amortization	**(24.54)**	—	—	—	—	**(24.54)**	—	—
Administrative expenses and other	**(7.61)**	—	—	—	—	**(7.61)**	—	—
Earnings before income taxes	**25.87**	—	—	—	—	**25.87**	—	—
Other International								
North Africa/Near East (b)								
Gross price	**76.02**	—	—	—	—	**76.02**	—	—
Royalties	**(46.46)**	—	—	—	—	**(46.46)**	—	—
Operating costs	**(2.21)**	—	—	—	—	**(2.21)**	—	—
Operating netback	**27.35**	—	—	—	—	**27.35**	—	—
Depreciation, depletion and amortization	**(2.31)**	—	—	—	—	**(2.31)**	—	—
Administrative expenses and other	**(5.21)**	—	—	—	—	**(5.21)**	—	—
Earnings before income taxes	**19.83**	—	—	—	—	**19.83**	—	—
Other International								
Northern Latin America (g)								
Average price realized	**2.09**	—	—	—	—	**2.09**	—	—
Royalties	**(1.58)**	—	—	—	—	**(1.58)**	—	—
Operating costs	**(2.76)**	—	—	—	—	**(2.76)**	—	—
Operating netback	**(2.25)**	—	—	—	—	**(2.25)**	—	—
Depreciation, depletion and amortization	**(0.79)**	—	—	—	—	**(0.79)**	—	—
Administrative expenses and other	**0.12**	—	—	—	—	**0.12**	—	—
Earnings before income taxes	**(2.92)**	—	—	—	—	**(2.92)**	—	—
Total International (l)								
Average price realized	**67.42**	—	—	—	—	**67.42**	—	—
Royalties	**(19.25)**	—	—	—	—	**(19.25)**	—	—
Operating costs	**(8.22)**	—	—	—	—	**(8.22)**	—	—
Operating netback	**39.95**	—	—	—	—	**39.95**	—	—
Depreciation, depletion and amortization	**(13.74)**	—	—	—	—	**(13.74)**	—	—
Administrative expenses and other	**(5.79)**	—	—	—	—	**(5.79)**	—	—
Earnings before income taxes	**20.42**	—	—	—	—	**20.42**	—	—

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 and net of related transportation costs and excludes the realized impact of hedging activities unless stated.
(3) Cash operating costs – Total operations	–	Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense, taxes other than income taxes and the cost of bitumen imported from third parties. Per barrel amounts are based on total production volumes. For a reconciliation of this non-GAAP financial measure see Management's Discussion and Analysis.
(4) Total cash operating costs – Total operations	–	Include cash operating costs – Total operations as defined above and cash start-up costs. Per barrel amounts are based on total production volumes.
(5) Total operating costs – Total operations	–	Include total cash operating costs – Total operations as defined above and non-cash operating costs. Per barrel amounts are based on total production volumes.
(6) Cash operating costs – In-situ bitumen production	–	Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense and taxes other than income taxes. Per barrel amounts are based on in-situ production volumes only.
(7) Total cash operating costs – In-situ bitumen production	–	Include cash operating costs – In-situ bitumen production as defined above and cash start-up operating costs. Per barrel amounts are based on in-situ production volumes only.
(8) Total operating costs – In-situ bitumen production	–	Include total cash operating costs – In-situ bitumen production as defined above and non-cash operating costs. Per barrel amounts are based on in-situ production volumes only.

Explanatory Notes

* Excludes the impact of realized hedging activities.

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

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