FIRST QUARTER 2010

Report to shareholders for the period ended March 31, 2010

Suncor Energy reports first quarter results

All financial figures are unaudited and in Canadian dollars unless noted otherwise. Certain financial measures referred to in this document are not prescribed by Canadian generally accepted accounting principles (GAAP). For a description of these measures, see Non-GAAP Financial Measures on pages 29 to 31. 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.

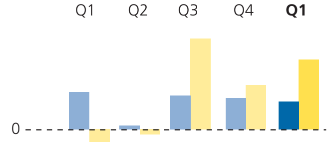
On August 1, 2009, Suncor Energy Inc. completed its merger with Petro-Canada. As such, the results for the three months ended March 31, 2010 reflect the results of the post-merger Suncor and the comparative figures for the three months ended March 31, 2009 reflect solely the results of legacy Suncor prior to the merger.

Suncor Energy Inc. recorded first quarter 2010 net earnings of $716 million ($0.46 per common share), compared to a net loss of $189 million ($0.20 per common share) for the first quarter of 2009. Operating earnings(1) in the first quarter of 2010 were $287 million ($0.18 per common share), compared to $380 million ($0.41 per common share) in the first quarter of 2009.

The decreased operating earnings were primarily due to reduced production volumes at our oil sands operations, as the company recovered from the impact of two upgrader fires. This was partially offset by additional upstream production, as a result of the merger with Petro-Canada. The company also benefited from higher benchmark crude oil prices in the quarter, partially offset by the stronger Canadian dollar relative to the U.S. dollar.

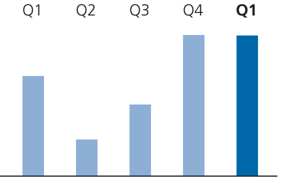
Cash flow from operations(2) was $1.124 billion ($0.72 per common share) in the first quarter of 2010, compared to $801 million ($0.86 per common share) in the first quarter of 2009. The increase in cash flow from operations was primarily due to the increased volumes added as a result of the merger.

Earnings by Quarter
($ millions)



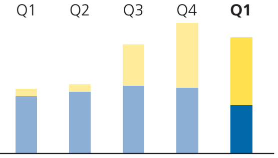
	2009 Q1	2009 Q2	2009 Q3	2009 Q4	**2010 Q1**
Net earnings (loss)	(189)	(51)	929	457	**716**
Operating earnings(1)	380	38	343	323	**287**

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



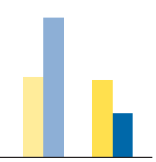
2009 Q1	2009 Q2	2009 Q3	2009 Q4	**2010 Q1**
801	295	574	1,129	**1,124**

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



	2009 Q1	2009 Q2	2009 Q3	2009 Q4	**2010 Q1**
Other	36.5	35.1	201.7	320.0	**330.0**
Oil Sands (including Syncrude)	278.0	301.0	330.1	318.2	**234.6**
Total	314.5	336.1	531.8	638.2	**564.6**

Ratios
(per cent)
for the twelve months ended March 31, 2010



	2009	**2010**
Return on average shareholders' equity	9.2	**8.8**
Return on capital employed(4)	16.0	**4.9**

(1) Non-GAAP measure. See page 2 for a reconciliation of net earnings to operating earnings.

(2) Non-GAAP measure. See page 30.

(3) Includes Suncor's proportionate production share from the Syncrude joint venture.

(4) Non-GAAP measure. Excludes capitalized costs related to major projects in progress. See page 30.

Operating Earnings

Operating earnings is a non-GAAP measure that the company uses to evaluate operating performance, which management believes allows better comparability between periods. Operating earnings is calculated by adjusting net earnings for significant one-time items and items that are not indicative of operating performance. See pages 29 to 31 for a discussion of non-GAAP financial measures.

Three months ended March 31 ($ millions, after-tax)	**2010**	2009
Net earnings (loss) as reported	**716**	(189)
Change in fair value of commodity derivatives used for risk management	**(8)**	266
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(230)**	148
Mark-to-market valuation of stock-based compensation	**(51)**	19
Project start-up costs	**9**	11
Costs related to deferral of growth projects	**30**	125
Merger and integration costs	**16**	—
Gains on significant disposals	**(195)**	—
Operating earnings	**287**	380

Suncor's total upstream production during the first quarter of 2010 averaged 564,600 barrels of oil equivalent (boe) per day, compared to 314,500 boe per day during the first quarter of 2009. The first quarter of 2010 reflects the results of additional upstream production volumes related to the merger with Petro-Canada, which were not included in the volumes for the first quarter of 2009.

Oil Sands production (excluding proportionate production share from the Syncrude joint venture) contributed an average 202,300 barrels per day (bpd) in the first quarter of 2010, compared to first quarter 2009 production of 278,000 bpd. Production was negatively impacted during the first quarter of 2010, due to unplanned maintenance activities following fires at upgraders in December 2009 and February 2010. Repairs were completed and oil sands upgrading facilities have since returned to full rates.

"While we were slower out of the gate than we'd hoped for this year due to upsets at our oil sands operations, the balance of the business performed well and oil sands production is firmly back on track," said Rick George, president and chief executive officer. "With both upgraders back to full production, we achieved an average oil sands production of approximately 333,000 barrels per day in April – our strongest month on record."

Cash operating costs for our oil sands operations (excluding Syncrude) increased to $54.85 per barrel in the first quarter of 2010, compared to $33.70 per barrel during the first quarter of 2009. The increase in cash operating costs per barrel was primarily a reflection of lower production levels.

Suncor's proportionate production share from the Syncrude joint venture contributed an average of 32,300 bpd of production during the first quarter of 2010.

Natural Gas production averaged 733 million cubic feet equivalent (mmcfe) per day in the first quarter of 2010, compared to 219 mmcfe per day during the first quarter of 2009, primarily due to the addition of Petro-Canada natural gas assets.

International and Offshore production contributed an average 207,800 boe per day during the first quarter of 2010. While production was negatively affected by minor unplanned outages at the company's North Sea operations, and by limitations on production quotas in Libya, all of the East Coast Canada assets exceeded management's production expectations during this quarter.

Total sales of refined petroleum products from Refining and Marketing averaged 82,200 cubic metres per day during the first quarter of 2010 compared to 31,400 cubic metres per day from the legacy Suncor business during the first quarter of 2009, reflecting the merger with Petro-Canada. Operating earnings increased over the same period last year due primarily to increased volumes as a result of the merger, despite a general decline in refining margins.

Growth and Operational Update

Construction was completed ahead of schedule and within budget on the $1.2 billion Ebla gas development in central Syria. Production from the Ebla gas project was introduced into the Syrian gas network in March 2010 and first commercial gas was delivered on April 19, 2010, following the successful completion of the performance testing period. The facility has a planned production capacity of 80 mmcf per day of natural gas in addition to related liquified petroleum gas and condensate volumes.

Construction continued on the Firebag Stage 3 in-situ oil sands project. The planned $3.6 billion expansion is expected to achieve first production during the second quarter of 2011, with volumes ramping up over an estimated 18-month period toward a planned production capacity of approximately 62,500 bpd of bitumen per day.

In March, the Alberta Energy Resources Conservation Board approved Suncor's application to develop three additional stages of its Firebag project. Firebag Stages 4, 5 and 6 each have a planned production capacity of approximately 62,500 bpd. Engineering and planning activities related to Firebag Stage 4 continued during the first quarter to support a target of first bitumen production in the fourth quarter of 2012.

"Regulatory approval for Firebag Stages 4 to 6 provides additional depth to an already substantial portfolio of growth projects," said George. "We'll continue to review that portfolio and expect to outline the next stages of our growth strategy by the end of the year."

In addition to work on expansion of the Firebag project, work is also underway on an extension to the East Coast Canada White Rose field (of which Suncor has a 26.125% interest); expansion of the company's St. Clair ethanol plant; and construction of a naphtha unit, designed to increase the value of the company's Oil Sands product mix.

"We have confirmed our capital synergy target of $1 billion per year through improved sequencing and timing of our projects, a larger pool of high-quality projects to pick from, and capital savings realized as a result of our two companies coming together," said George.

As part of its strategic business alignment, Suncor continued with plans to divest of a number of non-core assets. To date, Suncor has disposed of, or reached agreements to dispose of, assets for aggregate consideration of approximately $1.5 billion.

- On March 1, 2010, Suncor completed the sale of substantially all of its U.S. Rockies upstream assets for net proceeds of US$481 million. Remaining U.S. Rockies upstream assets were sold shortly thereafter.
- On March 31, 2010, the company completed the sale of other non-core natural gas properties, located in northeast British Columbia, called Jedney/Blueberry, for net proceeds of $383 million.
- On March 24, 2010, the company reached an agreement to sell certain natural gas assets located in central Alberta known as Rosevear and Pine Creek. The sale, for proceeds of $235 million, is expected to close in the second quarter of 2010.
- On February 25, 2010, the company reached an agreement to sell all of its assets in Trinidad and Tobago. The sale, for proceeds of US$380 million, is expected to close during the second quarter of 2010.

Remaining proposed divestments include certain natural gas assets in Western Canada and non-core North Sea assets, including all assets in The Netherlands. While the timeline for the divestment of assets remains flexible, Suncor expects most of the remaining sales to occur during 2010. The proceeds of these, and previous sales, are planned to go towards reducing the company's debt.

"From refocusing our asset base and reducing debt, to realizing synergies and aligning processes and platforms across the company – merger integration is on plan and proceeding well," said George.

Outlook

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

The following operational outlook has been revised from the operational outlook, previously issued by management on February 2, 2010. The revisions are principally as follows:

- the Oil Sands production outlook has been adjusted to 280,000 bpd (+/−5%) from 300,000 bpd (+/−5%) primarily as a result of the two fires at the upgrading facilities in December 2009 and February 2010, which has also had an impact on the product sales mix, price realizations and cash operating costs;
- the Natural Gas production outlook before remaining targeted divestitures has been adjusted to 580 mmcfe per day (+/−5%) from 680 mmcfe per day (+/−5%) as a result of completed dispositions relating to assets in the U.S. Rockies and northeast British Columbia during the first quarter of 2010; this has also reduced the production outlook relating to targeted divestures;
- the East Coast Canada production outlook has been adjusted to 60,000 bpd (+/−5%) from 55,000 bpd (+/−5%) primarily as a result of observed performance to date;
- the International production outlook has been adjusted to 133,000 boe per day (+/−5%) from 138,000 boe per day (+/−5%) as a result of observed performance to date; and
- the International business production relating to targeted divestures outlook has been revised from 25,000 boe per day to 40,000 boe per day (+/−5%) primarily as a result of a decision in the first quarter of 2010 to sell additional North Sea assets.

The foregoing changes have also had a corresponding impact on the total production outlook which has been adjusted to 608,000 boe per day (+/−5%) from 644,000 boe per day (+/−5%) and total production related to remaining targeted divestures, which has been adjusted to 70,000 boe per day from 75,000 boe per day.

	Three Month Actuals Ended March 31, 2010	2010 Full Year Outlook
Total production (boe per day) – before remaining targeted divestitures (1)	**564,600**	608,000 (+/−5%)
Total production (boe per day) – related to remaining targeted divestitures (1)	**N/A**	70,000
Oil Sands (2)		
Production (bpd)	**202,300**	280,000 (+/−5%)
Sales (3)		
Diesel	**7%**	9%
Sweet	**31%**	36%
Sour	**41%**	46%
Bitumen	**21%**	9%
Realization on crude sales basket (3), (4)	**WTI @ Cushing less Cdn$8.86 per barrel**	WTI @ Cushing less Cdn$7.00 to Cdn$8.00 per barrel
Cash operating costs (5)	**$54.85 per barrel**	$38 to $42 per barrel
Syncrude production (bpd)	**32,300**	38,000 (+/−5%)
Natural Gas		
Production (6) (mmcfe per day) – before remaining targeted divestitures (1)	**733**	580 (+/−5%)
Production (6) (mmcfe per day) – related to remaining targeted divestitures (1)	**N/A**	180
Natural gas	**89%**	91%
Crude oil and liquids	**11%**	9%
East Coast Canada		
Production (bpd)	**74,600**	60,000 (+/−5%)
International		
Production (boe per day) – before targeted divestitures (1)	**133,200**	133,000 (+/−5%)
Production (boe per day) – related to targeted divestitures (1)	**N/A**	40,000
Crude oil and liquids (1)	**85%**	84%
Natural gas (7)	**15%**	16%

(1) Actual production results will be impacted by the timing of planned divestments. Planned divestments included in this Outlook table are not directly comparable to discontinued operations presented in the company's March 31, 2010 unaudited interim Consolidated Financial Statements, as certain assets targeted for sale have not met the criteria for classification as discontinued operations, as determined in accordance with GAAP.

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

(3) Based on first quarter results and expectations for the balance of the year, the outlook for sales mix and realization on crude sales basket has been updated. The 2010 outlook provided in our Fourth Quarter 2009 Report to Shareholders was diesel – 8%, sweet – 39%, sour – 46% and bitumen – 7%. The original realization on crude sales basket was WTI @ Cushing less Cdn$4.75 to Cdn$5.75 per barrel.

(4) Excludes the impact of hedging activities.

(5) Cash operating cost estimates (excluding Syncrude) are based on the following assumptions: (i) production volumes and sales mix as described in the table above; and (ii) a natural gas price of $5.00 per gigajoule ($5.28 per mcf) at AECO.

(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.

(7) Based on first quarter results and expectations for the balance of the year, the International sales mix has been updated. The 2010 outlook provided in the Fourth Quarter 2009 Report to Shareholders was crude oil and liquids – 87% and natural gas – 13%.

This outlook is based on Suncor's current estimates, projections and assumptions for the 2010 fiscal year and is subject to change. Assumptions are based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be relevant. Assumptions for the Oil Sands 2010 full year outlook include reliability and operational efficiency initiatives which we expect to minimize further unplanned maintenance in 2010. Assumptions for the Natural Gas, East Coast Canada and International 2010 full year outlook include reservoir performance, drilling results, facility reliability, changes in production quotas and successful execution of planned turnarounds.

Risk Factors Affecting Performance

Factors that could potentially impact Suncor's operational and financial performance for 2010 include, but are not limited to:

- Bitumen supply. Ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage and in-situ reservoir performance could impact 2010 production targets.
- Performance of recently commissioned facilities. Production rates while new equipment is being lined out are difficult to predict and can be impacted by unplanned maintenance.
- Unplanned maintenance. Production estimates could be impacted if unplanned work is required at any of our mining, production, upgrading, refining, pipeline, or offshore assets.
- Planned turnarounds. Production estimates could be impacted if planned turnarounds are not effectively executed.
- Planned divestitures. Our inability to execute planned divestitures could impact our debt management and capital expenditure plans.
- Commodity prices. Significant declines in natural gas commodity prices could result in the shut-in of some of our natural gas production.
- Foreign operations. Suncor's foreign operations and related assets are subject to a number of political, economic and socio-economic risks. Suncor's operations in Libya may be constrained by production quotas.

The preceding paragraphs and tables contain forward-looking information that is subject to a number of risks and uncertainties, many of which are beyond the company's control. For additional information on risks, uncertainties and other factors that could cause actual results to differ, please see page 31.

MANAGEMENT'S DISCUSSION AND ANALYSIS

May 3, 2010

This Management's Discussion and Analysis (MD&A) contains forward-looking information based on Suncor's current expectations, estimates, projections and assumptions. This information is subject to a number of risks and uncertainties, including those discussed in this MD&A and Suncor's other disclosure documents, 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 31.

This MD&A should be read in conjunction with Suncor's March 31, 2010 unaudited interim Consolidated Financial Statements and the accompanying notes. 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 discussed in Non-GAAP Financial Measures on pages 29 to 31.

In order to provide shareholders with full disclosure relating to potential future capital expenditures, we have provided cost estimates for projects that, in some cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amounts are expected to differ and these differences may be material. For a further discussion of our significant capital projects, see the Significant Capital Project Update on page 26.

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, referred to in this MD&A as the "merger". For further information with respect to the merger, please refer to note 2 of the December 31, 2009 audited Consolidated Financial Statements and the accompanying notes.

The unaudited Interim Consolidated Financial statements include the results of post-merger Suncor from August 1, 2009. As such, amounts disclosed in this MD&A for the three month periods ended March 31, 2010, December 31, 2009, and September 30, 2009 reflect results of the post-merger Suncor whereas the comparative figures for the three month period ended March 31, 2009 and all other comparative periods prior to September 30, 2009 reflect solely the 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.

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 Annual Information Form dated March 5, 2010 (the 2009 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.

OVERVIEW AND HIGHLIGHTS OF CONSOLIDATED RESULTS

Description of the Business

Suncor is an integrated energy company headquartered in Calgary, Alberta. The company operates in four business segments: Oil Sands, Natural Gas, International and Offshore, and Refining and Marketing. In addition, the company engages in third-party energy marketing and trading activities, and has investments in renewable energy opportunities, including Canada's largest ethanol plant by volume, as well as partnerships in four wind power projects.

As part of its ongoing strategic business alignment, Suncor is in the process of divesting a number of non-core Natural Gas assets, all Trinidad and Tobago assets and certain non-core North Sea assets, including all assets in The Netherlands. Assets that have been sold during the period, or that have reached a certain point in the sales process, are presented as discontinued operations, as determined in accordance with GAAP. Certain non-core Natural Gas assets that the company has targeted for sale have not met certain criteria to be classified as discontinued operations, and continue to be reported as part of the company's continuing operations at this time.

Quarterly Consolidated Financial Summary

Three months ended ($ millions, except per share)	**Mar 31 2010**	Dec 31 2009	Sept 30 2009	June 30 2009	Mar 31 2009	Dec 31 2008	Sept 30 2008	June 30 2008
Revenues (net of royalties) (1)	**7 546**	7 636	8 443	4 768	4 633	6 952	8 507	7 640
Net earnings (loss)								
Continuing operations	**475**	479	940	(52)	(192)	(218)	801	815
Discontinued operations	**241**	(22)	(11)	1	3	3	14	14
	716	457	929	(51)	(189)	(215)	815	829
Net earnings (loss) from continuing operations per common share								
Basic	**0.30**	0.31	0.75	(0.06)	(0.21)	(0.24)	0.86	0.88
Diluted	**0.30**	0.30	0.75	(0.06)	(0.21)	(0.24)	0.84	0.86
Net earnings (loss) per common share								
Basic	**0.46**	0.29	0.69	(0.06)	(0.20)	(0.24)	0.87	0.89
Diluted	**0.46**	0.29	0.68	(0.06)	(0.20)	(0.24)	0.86	0.87
Operating earnings (loss) (2)								
Continuing operations	**214**	343	354	39	377	17	872	855
Discontinued operations	**73**	(20)	(11)	(1)	3	(3)	14	14
	287	323	343	38	380	14	886	869
Operating earnings per common share	**0.18**	0.21	0.27	0.04	0.41	0.02	0.95	0.93
Cash flow from operations (1), (2)	**1 124**	1 129	574	295	801	231	1 146	1 530
Return on capital employed (2), (3)	**4.9**	2.6	3.7	7.3	16.0	22.5	28.7	28.8

(1) Includes continuing and discontinued operations.

(2) Non-GAAP measure. See pages 29 and 30.

(3) Excludes capitalized costs related to major projects in progress.

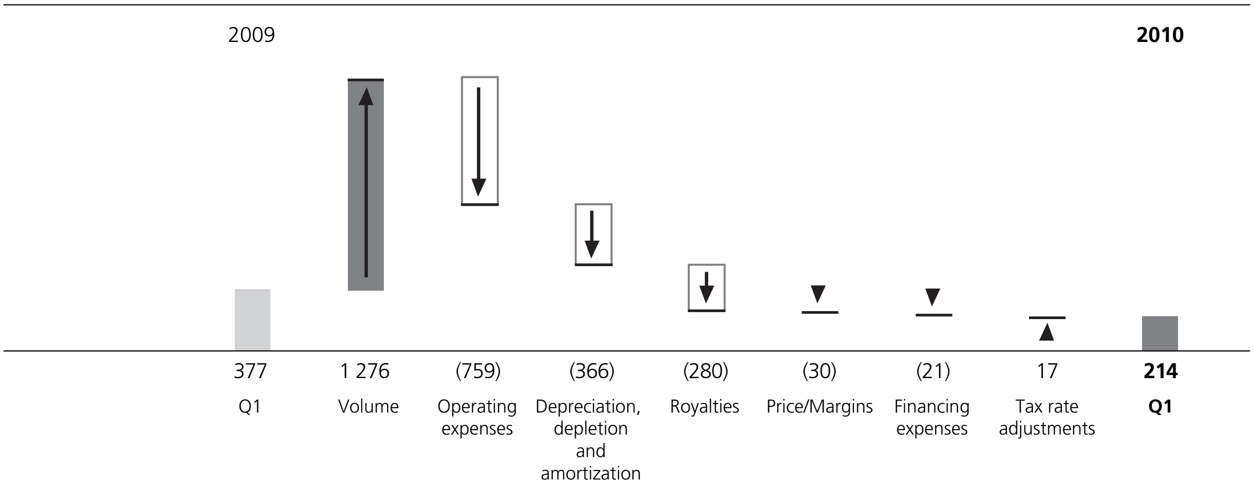
Highlights

- Net earnings for the first quarter of 2010 were $716 million, compared to a net loss of $189 million for the first quarter of 2009. Operating earnings in the first quarter of 2010 were $287 million, compared to $380 million in the first quarter of 2009. The decreased operating earnings were primarily due to reduced oil sands production volumes, as the company recovered from the impact of two upgrader fires. This was partially offset by additional upstream production, as a result of the merger with Petro-Canada. The company also benefited from higher benchmark crude oil prices in the quarter, partially offset by the stronger Canadian dollar relative to the U.S. dollar.

- Cash flow from operations was $1.124 billion in the first quarter of 2010, compared to $801 million in the first quarter of 2009. The increase in cash flow from operations was primarily due to the increased volumes added as a result of the merger.
- At Oil Sands, repairs were completed to Upgrader 2, during the first quarter, which was partially damaged by a fire in December 2009. The upgrader returned to normal operations in February 2010. On February 9, 2010 a second unrelated fire occurred at Upgrader 1, which was repaired and returned to full operations by April 1, 2010.
- Total upstream production this quarter was 564,600 barrels of oil equivalent (boe) per day, compared to 314,500 boe per day in the first quarter of 2009. Although production from the Oil Sands business was significantly affected by the fires to the upgraders, production was ahead of management's expectations in the Natural Gas and International and Offshore businesses.
- In Syria, test production from the Ebla Gas project was introduced into the Syrian Gas Network for the first time in March 2010. Commercial production was achieved on April 19, 2010.
- In March 2010, the company received regulatory approval to develop Firebag Stages 4, 5 and 6 of its in-situ oil sands expansion. Each stage has a planned production capacity of approximately 62,500 barrels per day.
- During the quarter, construction continued on Firebag Stage 3 in-situ oil sands project. The planned $3.6 billion expansion is currently expected to achieve first oil in the second quarter of 2011, with volumes ramping up over an estimated 18-month period toward planned production capacity of approximately 62,500 barrels of bitumen per day.
- On March 1, 2010, Suncor completed the sale of substantially all of its U.S. Rockies upstream assets for net proceeds of US$481 million. Remaining U.S. Rockies upstream assets were sold shortly thereafter.
- On March 31, 2010, the company completed the sale of other non-core natural gas assets in northeast British Columbia, called Jedney/Blueberry, for net proceeds of $383 million.
- The company also entered into two additional agreements during the first quarter of 2010 to sell non-core assets. The first agreement includes certain natural gas assets in central Alberta, known as Rosevear and Pine Creek, for aggregate consideration of $235 million, while a second agreement was reached to sell all of Suncor's assets in Trinidad and Tobago for aggregate consideration of US$380 million.

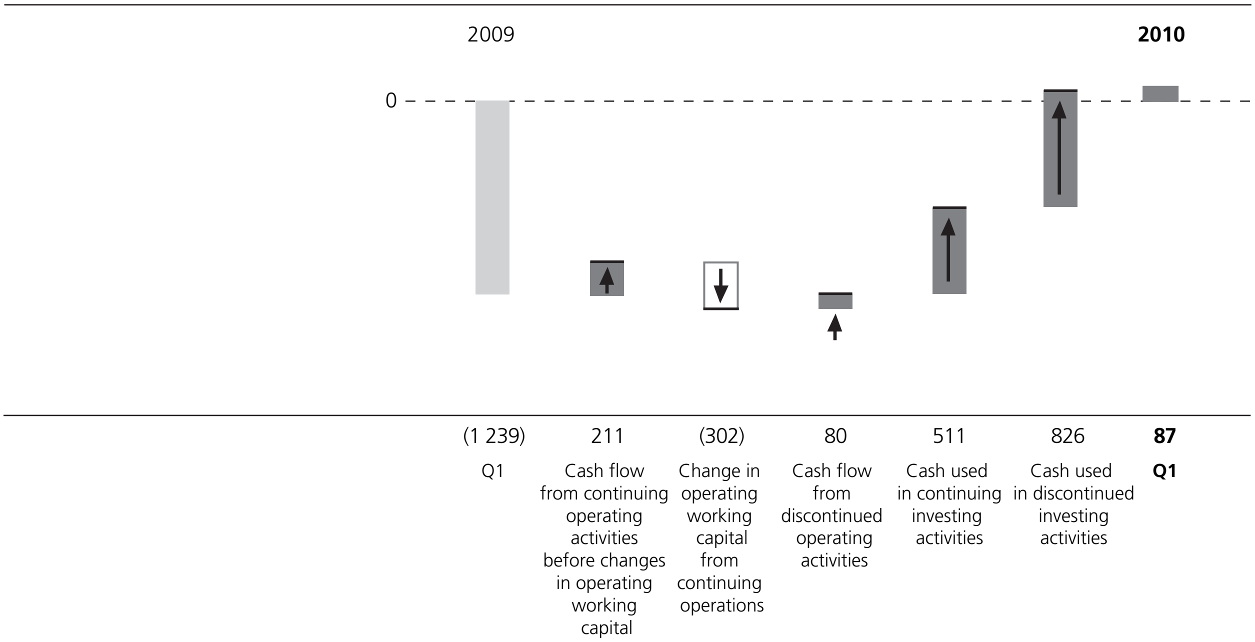
Consolidated Operating Earnings from Continuing Operations

($ millions)



Consolidated Net Cash Flow Before Financing Activities

($ millions)



Volumes

Three months ended March 31 (thousands of barrels of oil equivalent per day (mboe/d))	**2010**	2009
Continuing operations		
Oil Sands – operated	**202.3**	278.0
Oil Sands – Syncrude	**32.3**	—
Natural Gas	**102.4**	29.5
International and Offshore	**168.6**	—
	505.6	307.5
Discontinued operations		
Natural Gas	**19.8**	7.0
International and Offshore	**39.2**	—
	59.0	7.0
Total	**564.6**	314.5

The impact of the fires at Upgrader 2 in December 2009 and Upgrader 1 in February 2010 negatively affected production. This was partially offset by Syncrude volumes contributed from the merger. As a result of the recent incidents at the upgrading facilities, Suncor's outlook for Oil Sands production for 2010 has been revised (see page 4).

Natural Gas total production from continuing and discontinued operations was 733 mmcfe per day. As a result of the assets divested in the first quarter of 2010, Suncor's outlook for Natural Gas production for 2010 has been revised (see page 4).

International and Offshore production was 207,800 boe per day. While production was negatively affected by minor unplanned outages at the company's North Sea operations, and by limitations on production quotas in Libya, all of the East Coast Canada assets exceeded management's expectations during the quarter. As a result of performance in the first quarter of 2010 and update to assets included in the strategic divestment plan, Suncor's outlook for production from this business has been revised (see page 4).

Commodity Prices

Average Benchmarks

Three months ended ($ average for the period)		**Mar 31 2010**	Dec 31 2009	Sept 30 2009	June 30 2009	Mar 31 2009	Dec 31 2008	Sept 30 2008	June 30 2008
West Texas Intermediate (WTI) crude oil at Cushing	US$/barrel	**78.70**	76.20	68.30	59.60	43.10	58.75	118.00	124.00
Dated Brent crude oil at Sullom Voe	US$/barrel	**76.25**	74.55	68.25	58.85	44.40	54.90	114.80	121.40
Dated Brent/Maya FOB price differential	US$/barrel	**6.50**	5.25	5.10	3.75	5.90	10.10	8.35	18.40
Canadian 0.3% par crude oil at Edmonton	Cdn$/barrel	**80.45**	77.00	70.60	65.30	50.10	64.65	123.00	126.40
Light/heavy crude oil differential of WTI at Cushing less Western Canadian Select at Hardisty	US$/barrel	**8.95**	12.10	10.10	7.50	8.95	19.30	18.05	21.65
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**5.35**	4.25	3.00	3.65	5.65	6.80	9.25	9.35
New York Harbour 3-2-1 crack(1)	US$/barrel	**7.95**	5.80	7.50	8.35	9.85	5.40	10.65	11.50
Chicago 3-2-1 crack(1)	US$/barrel	**5.65**	4.15	7.65	10.15	8.95	5.25	16.45	12.90
Seattle 3-2-1 crack(1)	US$/barrel	**8.55**	5.95	12.80	13.35	13.45	5.25	17.20	16.45
Gulf Coast 3-2-1 crack(1)	US$/barrel	**6.75**	4.50	6.75	8.40	8.90	2.90	14.60	12.10
Exchange rate	US$/Cdn$	**0.96**	0.94	0.91	0.85	0.80	0.82	0.96	0.99

(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 the same location and dividing by three.

SEGMENTED EARNINGS AND CASH FLOWS

Oil Sands

Three months ended March 31 ($ millions, unless otherwise noted)	**2010**	2009
Gross revenues	**1 970**	1 108
Royalties	**70**	8
Net revenues	**1 900**	1 100
Production (excluding Syncrude) (thousands of bpd)	**202.3**	278.0
Syncrude production (thousands of bpd)	**32.3**	—
Average sales price (excluding Syncrude) ($/barrel) (1)	**70.21**	59.45
Net earnings (loss)	**76**	(110)
Operating earnings (2)	**104**	293
Cash flow from operations (2)	**262**	480
Cash operating costs (excluding Syncrude) ($/barrel) (2)	**54.85**	33.70
Sales mix (light/heavy mix) (%)	**38/62**	54/46
ROCE (2), (3)	**5.2**	22.9
ROCE (2), (4)	**3.1**	13.9

(1) Calculated before royalties and net of related transportation costs.

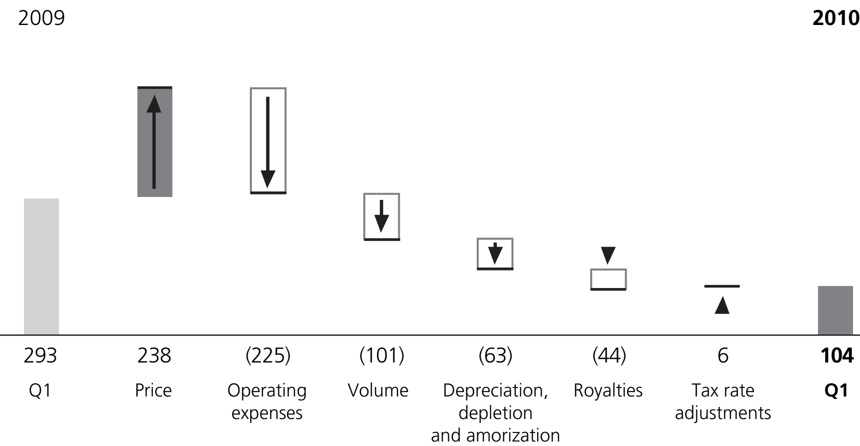
(2) Non-GAAP measure. See pages 30 and 31.

(3) Excludes capitalized costs related to major projects in progress.

(4) Includes capitalized costs related to major projects in progress.

Operating Earnings

($ millions)



Oil Sands recorded net earnings of $76 million in the first quarter of 2010, compared with a net loss of $110 million in the first quarter of 2009. Operating earnings for the first quarter of 2010 were $104 million, compared to operating earnings of $293 million in the first quarter of 2009. Operating earnings were lower primarily due to the impact of upgrader fires in December 2009 and February 2010. Reduced production volumes resulted in decreased sales, while related operating expenses remain relatively fixed, impacting both earnings and cash flow from operations. This was partially offset by higher average price realizations and the recovery of fire-related insurance proceeds from Suncor's captive insurance company. Third-party insurance recoveries related to the fires are expected to be minimal.

Cash flow from operations was $262 million in the first quarter of 2010, compared to $480 million in the first quarter of 2009. The decrease was a result of the same factors that impacted operating earnings.

Volumes

Oil Sands production averaged 202,300 bpd (excluding Syncrude) in the first quarter of 2010, compared to 278,000 bpd during the first quarter of 2009. Production was negatively impacted by a fire and subsequent maintenance at Upgrader 2 in December, 2009. Upgrader 2 returned to normal production on February 4, 2010. On February 9, 2010, a second unrelated fire occurred at Upgrader 1. The repairs related to this fire were completed and Upgrader 1 was restored to normal operations on April 1, 2010.

The fires also negatively affected sales mix during the quarter, with diesel and sweet crude products comprising 38% of total sales volume during the first quarter of 2010, compared to 54% for the same period in 2009. As a result of the fires, the company has revised its outlook for Oil Sands production for 2010 (see page 4).

Syncrude contributed an average 32,300 bpd of sweet synthetic crude oil production in the first quarter of 2010, which was 14% of Oil Sands total production. Apart from the Syncrude production, the merger did not result in increased Oil Sands production volumes. Production from MacKay River was included in Suncor's reported production during the first quarter of 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 prior to August 1, 2009.

Prices

Sales price realization from Oil Sands operated assets averaged $70.21 per barrel during the first quarter of 2010 compared to $59.45 per barrel during the same period in 2009. Benchmark WTI crude oil prices and premiums to WTI for sweet and sour crude blends were both higher during the three months ended March 31, 2010 as compared to the same period in 2009. However, as crude oil prices are based on U.S. dollar benchmarks, the stronger Canadian dollar in the first quarter of

2010 negatively impacted the company's realized prices. WTI crude oil price averaged US$78.70 per barrel during the first quarter of 2010, compared to US$43.10 per barrel during the same period in 2009, and the US$/Cdn$ exchange rate averaged 0.96 in the first quarter of 2010, compared to 0.80 for the same period in 2009. Lower volumes during the quarter, as a result of the fires at the upgraders, prevented Oil Sands from fully taking advantage of these higher realized prices.

Operating Expenses

Operating expenses were higher in the first quarter of 2010 compared to the first quarter of 2009, primarily due to impacts from the upgrader fires. Purchases of crude oil and products increased both to meet customer commitments and to obtain diluent as the company was unable to produce sufficient quantities to meet its operating requirements. In addition, certain planned maintenance scheduled for later in 2010 was accelerated while upgrader operations were disrupted.

During the first quarter of 2010, cash operating costs (excluding Syncrude) increased to $54.85 per barrel, from $33.70 per barrel in the first quarter of 2009, primarily due to the decrease in production. Refer to page 31 for further details on cash operating costs as non-GAAP financial measure, including the calculation and reconciliation to GAAP measures.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization expenses increased in the first quarter of 2010, compared to the first quarter of 2009. The depreciable cost base has grown as new assets have been commissioned and acquired, primarily as a result of the merger with Petro-Canada, since the first quarter of 2009.

Royalties

Royalties increased to $70 million in the first quarter of 2010 from $8 million in the first quarter of 2009 as a result of higher commodity prices. Low bitumen reference prices in the first quarter of 2009 resulted in royalties being calculated at minimum royalty rates. In the first quarter of 2010, the impact of the upgrader fires on volumes resulted in minimum royalty rates until March, when improved volumes and higher prices increased effective royalty rates. In-situ projects continued in the pre-payout phase and royalties were calculated on the minimum royalty percentage of "Revenues", which is a rate based on the Canadian dollar equivalent of WTI up to a maximum of 9%. For a more detailed description of the Alberta Crown royalty regime in effect for the company's operated Oil Sands assets, see pages 16-18 of Suncor's 2009 Annual Report.

The following table provides an estimation of royalties for Oil Sands operations (excluding Syncrude) in the years 2010 to 2013 under three price scenarios, and certain assumptions on which we have based our estimates for those price scenarios.

WTI Price/bbl US$	**60**	**80**	**100**
Natural gas (Alberta spot) Cdn$/mcf at AECO	5.15	5.60	6.20
Light/heavy crude oil differential of WTI at Cushing less Maya at the U.S. Gulf Coast US$	8.35	8.90	11.50
Differential of Maya at the U.S. Gulf Coast less Western Canadian Select at Hardisty US$	4.40	4.55	4.60
US$/Cdn$ exchange rate	0.85	0.97	1.00
Crown Royalty Expense (based on percentage of total Oil Sands gross revenue) (excluding Syncrude))% (1)			
2010 (2)	4-6	9-11	9-12
2011-2013	4-7	9-11	12-14

(1) Reflects Crown's interim bitumen valuation methodology.

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

(ii) The government enacted the new Oil Sands Allowed Costs (Ministerial) Regulations as part of the implementation of the New Royalty Framework effective January 1, 2009. Further clarification of some Allowed Cost business rules is still expected. The terms of the Suncor RAA determine the royalty obligation through 2015 for the mining operations. However, potential changes to, and the interpretation of, the Allowed Cost regulations, could over time, have a significant impact on the amount of royalties payable.

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

For further information on risk factors related to royalty rates, please see page 54 of Suncor's 2009 AIF.

Planned Turnarounds

There is a 45 day planned maintenance scheduled for Upgrader 2 during the second quarter, and a 35 day planned turnaround scheduled in the third quarter of 2010. Production volumes are expected to be reduced by approximately 85,000 bpd in the second quarter and 35,000 bpd in the third quarter of 2010.

Syncrude undertook an extension and advancement of maintenance during the first quarter of 2010, and is expecting a coker turnaround in the third quarter of 2010.

Growth Update

The company is continuing with its planned growth initiatives related to the Firebag Stage 3 in-situ oil sands expansion. Production is expected to begin in the second quarter of 2011, with volumes ramping up over an estimated 18-month period toward planned production capacity of approximately 62,500 barrels of bitumen per day.

Spending will also be directed to Firebag Stage 4 to support a target of first bitumen production in the fourth quarter of 2012. Firebag Stage 4 also has planned production capacity of 62,500 barrels of bitumen per day. Construction of Firebag Stage 4 remains subject to Board approval.

Remaining 2010 capital growth spending will be directed towards completion of a naphtha unit at Upgrader 2 which is intended to increase the value of the upgrader's product mix. The company expects the plant will be operational by the third quarter of 2011.

For an update on our significant capital projects currently in progress, see page 26.

Risk Factors Affecting Performance

The financial and operating performance of the company's Oil Sands business is potentially affected by a number of factors, including, but not limited to, the following:

- Production reliability risk. Our ability to reliably operate our oil sands facilities in order to meet production targets.
- Our ability to finance oil sands growth and sustaining capital expenditures in a volatile commodity pricing environment. Also refer to Financial Condition and Liquidity on page 25.
- Bitumen supply. Ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage and in-situ reservoir and equipment performance could impact 2010 production targets.
- Performance of recently commissioned facilities. Production rates while new equipment is being lined out are difficult to predict and can be impacted by unplanned maintenance.
- Ability to manage production operating costs. Operating costs could be impacted by inflationary pressures on labour, volatile pricing for natural gas used as an energy source in oil sands processes, and planned and unplanned maintenance. We continue to address these risks through such strategies as application of technologies that help manage operational workforce demand, offsetting natural gas purchases through internal production, investigation of technologies that mitigate reliance on natural gas as an energy source, and an increased focus on preventative maintenance.
- Our ability to complete projects both on time and on budget. This could be impacted by competition from other projects (including other Oil Sands projects) for goods and services and demands on infrastructure in Fort McMurray and the surrounding area (including housing, roads and schools). We continue to address these issues through a comprehensive recruitment and retention strategy, working with the community to determine infrastructure needs, designing oil sands expansion to reduce unit costs, seeking strategic alliances with service providers and maintaining a strong focus on engineering, procurement and project management.
- Potential changes in the demand for refinery feedstock and diesel fuel. Our strategy is to reduce the impact of this issue by entering into long-term supply agreements with major customers, expanding our customer base and offering a variety of blends of refinery feedstock to meet customer specifications.
- Volatility in crude oil and natural gas prices, foreign exchange rates and the light/heavy and sweet/sour crude oil differentials. We mitigate some of the risk associated with changes in commodity prices through the use of derivative financial instruments (see page 27).
- Logistical constraints and variability in market demand, which can impact crude movements. These factors can be difficult to predict and control.
- Changes to royalty and tax legislation and related agreements that could impact our business. While fiscal regimes in Alberta and Canada are generally stable relative to many global jurisdictions, royalty and tax treatments are subject to periodic review, the outcome of which is not predictable and could result in changes to the company's planned investments, and rates of return on existing investments.
- Our relationship with our trade unions. Work disruptions have the potential to adversely affect oil sands operations and growth projects. The Communications, Energy and Paperworkers Union Local 707 represents approximately 2,900 Oil Sands employees.

Additional risks, assumptions and uncertainties are discussed on page 31 under Forward-Looking Information.

Natural Gas

Three months ended March 31 ($ millions, unless otherwise noted)	**2010**	2009
Gross revenues from continuing operations	**344**	91
Royalties from continuing operations	**53**	17
Net revenues from continuing operations	**291**	74
Average sales price from continuing operations – natural gas ($/mcf) (1)	**5.29**	5.51
Average sales price from continuing operations – natural gas liquids and crude oil ($/barrel) (1)	**70.02**	45.91
Gross production		
Continuing operations (mmcfe/d)	**614**	177
Discontinued operations (mmcfe/d)	**119**	42
	733	219
Net earnings (loss)		
Continuing operations	**34**	(13)
Discontinued operations	**187**	3
	221	(10)
Operating earnings (loss) (2)		
Continuing operations	**—**	(13)
Discontinued operations	**19**	3
	19	(10)
Cash flow from continuing operations (2)	**182**	40
ROCE (2) %	**1.2**	5.0

(1) Calculated before royalties and net of transportation costs.

(2) Non-GAAP measure. See page 30.

The Natural Gas business recorded net earnings of $221 million in the first quarter of 2010, compared with a net loss of $10 million in the first quarter of 2009. The $231 million increase is predominantly related to gains realized on the assets sold in the first quarter of 2010. Total operating earnings were $19 million in the first quarter of 2010, compared to an operating loss of $10 million in the first quarter of 2009. The increase primarily relates to the positive impact of incremental production volumes as a result of the merger and higher price realizations for crude oil and natural gas liquids (NGLs). Factors that negatively affected total operating earnings were a decline in natural gas prices from the first quarter of 2009 and higher operating expenses, royalties and depreciation, depletion and amortization expenses relating to the increased production levels.

Discontinued Operations

Discontinued operations include the results, up to the closing date, of assets that have been sold during the quarter, as well as results from certain assets the company expects to sell. Comparative results have been restated to reflect the impact of operations that have been classified as discontinued during the first quarter of 2010.

During the first quarter of 2010, the Natural Gas business progressed on strategic divestment activities initiated during the latter part of 2009:

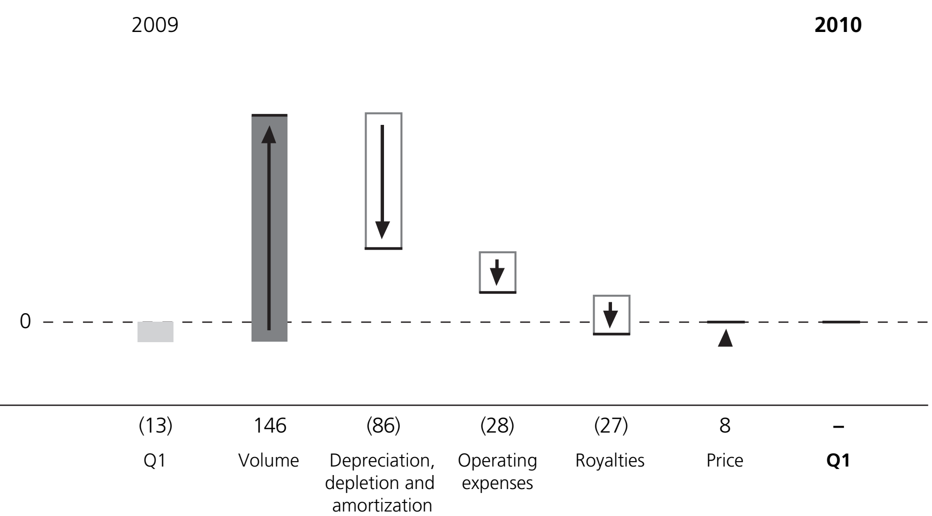
- On March 1, 2010, substantially all of Suncor's producing assets in the U.S. Rockies were sold for net proceeds of US$481 million. These assets produced an average 50 million cubic feet of natural gas (mmcf) per day and five thousand barrels of natural gas liquids and crude oil per day during the first two months of 2010. The company's remaining interests in the U.S. Rockies upstream assets were divested shortly thereafter.
- On March 31, 2010, the company sold certain non-core natural gas properties located in northeast British Columbia, known as Jedney/Blueberry, for net proceeds of $383 million. These assets produced an average of 44 million cubic feet of natural gas equivalent (mmcfe) per day during the first quarter of 2010.

- On March 24, 2010, the company reached an agreement to sell certain non-core natural gas properties located in central Alberta, known as Rosevear and Pine Creek. These assets produced an average of 23 mmcfe per day during the first quarter of 2010. The sale, for proceeds of $235 million, is expected to close during the second quarter of 2010.

Continuing Operations

Operating Earnings from Continuing Operations

($ millions)



Operating earnings from continuing operations were nil in the first quarter of 2010, compared to an operating loss from continuing operations of $13 million in the first quarter of 2009. Cash flow from continuing operations was $182 million in the first quarter of 2010, compared to $40 million in the first quarter of 2009. The improvement in operating earnings and cash flow from operations was due primarily to the same factors that impacted total operating earnings.

Volumes

Continuing operations production averaged 614 mmcfe per day in the first quarter of 2010, compared to 177 mmcfe per day during the same period in 2009. The increase primarily reflects assets acquired as a result of the merger.

Price

The average realized natural gas liquids and crude oil price increased to $70.02 per barrel in the first quarter of 2010, from $45.91 per barrel in the first quarter of 2009, reflecting the increase in benchmark crude oil prices. This was partially offset by a decrease in the average realized natural gas price to $5.29 per mcf for the first quarter of 2010, from $5.51 per mcf for the first quarter of 2009 as a result of the decline in benchmark natural gas prices. The net impact of the price variance was an increase in operating earnings from continuing operations of $8 million.

Royalties

Total royalties related to continuing operations increased to $53 million in the first quarter of 2010, from $17 million in the first quarter of 2009, as a result of volume increases. On a per unit basis, royalties declined to $0.96 per mcf in the first quarter of 2010 from $1.07 per mcf in the first quarter of 2009. This is attributed to lower benchmark commodity prices and reduced rates under the Alberta Government's New Royalty Framework. For a further discussion on the Alberta Crown royalties regime, see page 48 of the 2009 AIF.

Operating Expenses

The increased operating expenses relates to increased production levels, partially offset by operational efficiencies. Lifting costs from continuing operations were $1.27 per mcfe for the first quarter of 2010 compared to $1.51 per mcfe in the first quarter of 2009.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization (DD&A) expenses from continuing operations increased in the first quarter of 2010 compared to the same period in 2009 as a result of the merger. On a per unit basis, DD&A expenses have remained consistent quarter over quarter.

Gain on Asset Dispositions

During the first quarter, the disposal of a portion of our working interest in certain non-core lands in northeast British Columbia for proceeds of $40 million was included in net earnings from continuing operations.

Risk Factors Affecting Performance

The financial and operating performance of the company's Natural Gas business is potentially affected by a number of factors, including, but not limited to, the following:

- Consistently and competitively finding and developing reserves that can be brought on stream economically.
- Our ability to finance capital investment to replace reserves or increase processing capacity in a volatile commodity pricing and credit environment. Also refer to Financial Condition and Liquidity on page 25.
- Volatility in natural gas and liquids prices is not predictable and can significantly impact revenues.
- The accessibility and cost of mineral rights. Market demand influences the cost and available opportunities for mineral leases and acquisitions.
- Risk associated with a depressed market for asset sales, leading to losses on disposition.
- Risks and uncertainties associated with consulting with stakeholders and obtaining regulatory approval for exploration and development activities in our operating areas. These risks could increase costs and/or cause delays to or cancellation of projects.
- Risks and uncertainties associated with weather conditions, which can shorten the winter drilling season and impact the spring and summer drilling program, which may result in increased costs and/or delays in bringing on new production.

Additional risks, assumptions and uncertainties are discussed on page 31 under Forward-Looking Information.

International and Offshore

Three months ended March 31 ($ millions, unless otherwise noted)	2010
Gross revenues from continuing operations	**1 214**
Royalties	**339**
Net revenues from continuing operations	**875**
Production from continuing operations	
East Coast Canada production (thousands of boe/d)	**74.6**
U.K. (Buzzard) (thousands of boe/d)	**58.6**
Libya (thousands of boe/d)	**35.4**
Production from discontinued operations (thousands of boe/d)	**39.2**
Total Production (thousands of boe/d)	**207.8**
Average sales price from continuing operations (1)	
East Coast Canada ($/bbl)	**78.69**
North Sea ($/boe)	**72.36**
Libya ($/boe)	**73.40**
Net earnings	
Continuing operations	**209**
Discontinued operations	**54**
	263
Operating earnings (2)	
Continuing operations	**205**
Discontinued operations	**54**
	259
Cash flow from continuing operations (2)	**541**
ROCE (%) (2), (3)	**16.5**
ROCE (%) (2), (4)	**10.4**

(1) Calculated before royalties and net of transportation costs.

(2) Non-GAAP measure. See page 30.

(3) Excludes capitalized costs related to major projects in progress.

(4) Includes capitalized costs related to major projects in progress.

Suncor has continuing operations in the U.K. (Buzzard – 29.9% working interest), Norway, Libya, and Syria. There are discontinued operations located in The Netherlands and certain U.K. sections of the North Sea, as well as Trinidad and Tobago.

The company also has an interest in every major producing oil development off Canada's east coast. Suncor holds a 20% interest in Hibernia, a 27.5% interest in White Rose, a 22.7% interest in Hebron, and is the operator of Terra Nova with a 34% interest. The company also has a 19.5% interest in the Hibernia South Extension and a 26.125% interest in the White Rose North Amethyst and West White Rose Extensions.

All of these interests were acquired as a result of the merger. For further details related to the company's International and Offshore interests, see page 7 of the 2009 AIF.

Total operating earnings for the International and Offshore business were positively affected by higher commodity prices, slightly offset by a weakening U.S. dollar. Negatively affecting operating earnings this quarter were unplanned maintenance activities which impacted production levels at the Buzzard and Triton assets in the North Sea, as well as ongoing production quota constraints in Libya. The East Coast Canada operations were positively impacted by strong reservoir capability and facility reliability, and the early addition of new wells in the AA Block at Hibernia.

Discontinued Operations

Discontinued operations include the results, up to the closing date, of assets that we expect to sell. Comparative results have been restated to reflect the impact of operations that have been classified as discontinued during the first quarter of 2010.

In accordance with the company's strategic plans, Suncor entered into an agreement to sell all of its assets in Trinidad and Tobago, for gross proceeds of US$380 million. The sale is currently expected to close during the second quarter of 2010. Average production of offshore natural gas at the Trinidad and Tobago operations was 11,700 boe per day during the first quarter of 2010. Divestiture plans are also proceeding for certain other non-core North Sea assets, including all of the company's investments in The Netherlands. U.K. North Sea assets that are planned to be divested include Scott/Telford and Triton. The company expects to maintain its ownership positions in the producing Buzzard field, and exploration assets in the Hobby, Golden Eagle and Pink fields. Production volumes related to these assets averaged 27,500 boe per day during the first quarter of 2010.

Continuing Operations

Operating earnings from continuing operations were $205 million in the first quarter of 2010, impacted by the same factors affecting total operating earnings.

Cash flow from continuing operations of $541 million in the first quarter of 2010 has been impacted by the same factors affecting earnings.

Volumes

Net production from the Buzzard development in the U.K. sector of the North Sea averaged 58,600 boe per day, which was lower than management's expectations as a result of unplanned maintenance to the separator unit. Suncor's share of production in Libya, with an average of 35,400 barrels of oil per day in the first quarter of 2010, continues to be negatively affected by production quotas.

Suncor's share of Terra Nova production averaged 29,600 bpd during the quarter. The company's share of production from Hibernia also averaged 30,200 bpd for the quarter ended March 31, 2010, with strong reservoir capability and facility reliability continuing throughout the period. Suncor's share of White Rose's average production for the first quarter of 2010 was 14,800 bpd.

Prices

The average sales price for the U.K. (Buzzard) production was $72.36 per boe in the first quarter of 2010, while the average realized price for the sale of Libya production was $73.40 per boe.

East Coast Canada offshore average price realizations, which were $78.69 per barrel, benefited from strong benchmark crude oil prices this quarter.

Royalties

Total royalties in the International and Offshore segment during the first quarter of 2010 were $339 million, or 28% of gross revenue from continuing operations.

The following table sets forth an estimation of royalties related to Suncor's East Coast assets in 2010 for three price scenarios, and certain assumptions on which the estimates for those price scenarios have been based.

WTI Price/bbl US$	**60**	**80**	**100**
US$ / Cdn$ exchange rate	0.85	0.97	1.00
Crown Royalty Expense (based on percentage of gross revenue) %(1)			
2010 – Crude (tiered royalty rates assessed on gross or net revenue)	31-33	32-34	33-35

(1) For 2010, estimated royalty rates are based on actual year-to-date results plus forward months estimated as per assumptions.

For a further discussion on Crown royalties see page 18 of the 2009 Annual Report. The previous table contains forward-looking information and users of this information are cautioned that actual Crown royalty expense may vary from the percentages disclosed in the table. The percentages disclosed in the table were developed using the following assumptions: current agreements with the Government of Newfoundland and Labrador, current forecasts of production, capital and operating costs, and the forward estimates of commodity prices and exchange rates described in the table.

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

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

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

Operating Expenses

Operating expenses were favourably impacted by foreign exchange rates during the quarter, with minor offsets for unplanned maintenance at the Buzzard operations, and the ongoing seismic program in Libya.

Lifting and administrative costs at the East Coast Canada operations were all below management's expectations this quarter.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization expenses were higher than expected during the first quarter of 2010, as a result of higher than anticipated production levels.

Planned Turnarounds

There were no planned turnarounds at any of the International and Offshore assets during the first quarter of 2010.

For our continuing operations, the company has the following planned turnarounds in 2010. In the U.K., there is a three-week maintenance turnaround planned at the Buzzard operation in the second quarter of 2010. In East Coast Canada, there is a four-week turnaround scheduled for Terra Nova beginning in late June 2010, as well as turnarounds planned for White Rose and Hibernia, during the fourth quarter of 2010.

Growth Update

In Syria, test production from the Ebla gas project was introduced into the Syrian Gas Network for the first time in March 2010. Commercial production was achieved on April 19, 2010.

Two seismic surveys continue to acquire data in relation to the new Libya Exploration and Production Sharing Agreements. The results of seismic surveys, completed in 2009, are currently being processed. Site construction for the first of the exploration wells due to be drilled this year is complete and rig mobilization has commenced.

Development drilling continues for the North Amethyst portion of the White Rose Extensions, with first oil expected during the second quarter of 2010. Development drilling of North Amethyst will continue through 2012.

The West White Rose development is divided into two stages. The first stage was approved during the second quarter of 2009. Drilling for the first of two pilot wells is planned to commence later in 2010, with first oil expected to result by early in 2011. Drilling results from the first stage, combined with production evaluation and ongoing reservoir evaluation, will define the full field development scope.

Drilling commenced and first oil was achieved during the latter part of 2009 on the AA Block area of Hibernia South, in which Suncor holds a 20% interest. First oil is expected between 2013 and 2014 from the remainder of the Hibernia South Extension project, in which Suncor holds a 19.5% interest. In February 2010 final agreements were executed among the co-venturers and the Government of Newfoundland and Labrador, including the settlement of transportation deductions for royalty purposes.

For an update on our significant capital projects currently in progress, see page 26.

Risk Factors Affecting Performance

The financial and operating performance of the company's International and Offshore business is potentially affected by a number of factors, including, but not limited to, the following:

- Risks and uncertainties associated with international and offshore operations normally inherent in such activities such as development drilling, operation and development of such properties including unexpected formations or pressures, premature declines of reservoirs, fires, blow-outs, equipment failures and other accidents, uncontrollable flows of crude oil, natural gas or well fluids, pollution and other environmental risks.
- Consistently and competitively finding and developing reserves that can be brought on stream economically.
- Volatility in crude oil prices is not predictable and can significantly impact revenues.
- Performance after completion of maintenance not predictable and can significantly impact production rates.
- Risks and uncertainties associated with consulting with stakeholders and obtaining regulatory approval for exploration and development activities. These risks could increase costs and/or cause delays to or cancellation of projects and expansions to existing projects.
- Risks and uncertainties associated with weather conditions, which may result in increased costs and/or delays in bringing on new production.
- Our ability to finance capital investment to replace reserves or increase processing capacity in a volatile commodity pricing and credit environment. Also refer to Financial Condition and Liquidity on page 25.
- Risks associated with applicable legal and other regulatory requirements, including changes to tax, environmental and other legal and regulatory requirements, the outcome of which is not predictable and could result in changes to the company's planned investments, and rates of return on the company's existing investments.

Additional risks, assumptions and uncertainties are discussed on page 31 under Forward-Looking Information.

Refining and Marketing

Three months ended March 31 ($ millions, unless otherwise noted)	**2010**	2009
Revenues	**4 809**	1 413
Refined product sales volumes (thousands of cubic metres per day)		
Gasoline	**38.3**	16.4
Distillate	**28.4**	10.5
Other	**15.5**	4.5
	82.2	31.4
Net earnings	**139**	112
Operating earnings (1)	**131**	111
Cash flow from operations (1)	**328**	205
ROCE (%) (1)	**6.6**	0.6

(1) Non-GAAP measure. See page 30.

The Refining and Marketing business operates refineries in Edmonton, Alberta; Montreal, Quebec; Sarnia, Ontario; and Commerce City, Colorado with a total aggregate production capacity of 443,000 bpd, as well as a lubricants plant that is the largest producer of lubricant-base stocks in Canada. In addition, the Refining and Marketing business markets refined products to retail, commercial and industrial customers, primarily in Canada and Colorado, through a combination of company-owned, branded-dealer and joint venture-operated retail stations, a large Canadian national commercial road transport network and a bulk sales channel. Assets also include interests in pipelines and product terminals in Canada and the United States.

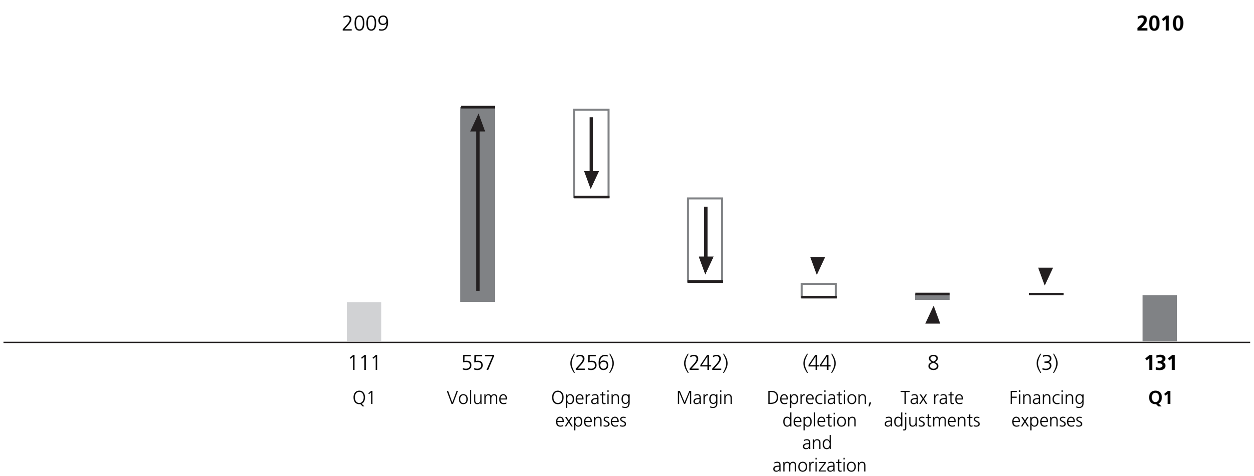
The nameplate capacity of our Edmonton refinery has been upwardly revised to 135,000 bpd from the previously disclosed 125,000 bpd. See page 22 of Suncor's 2009 AIF for further information. Starting January 1, 2010, refinery utilization will be calculated using the 135,000 bpd capacity.

The Refining and Marketing business recorded net earnings of $139 million in the first quarter of 2010, compared with $112 million in the first quarter of 2009. Operating earnings for the first quarter of 2010 were $131 million, compared with $111 million for the first quarter of 2009. As a result of the merger, refining capacity increased by 265,000 bpd. This increase, combined with the addition of the Petro-Canada national retail and wholesale businesses and the lubricants plant, enabled Refining and Marketing to deliver higher operating earnings in the first quarter of 2010, compared to the first quarter of 2009, despite a much weaker business environment.

Cash flow from operations was $328 million in the first quarter of 2010, compared to $205 million in the same period of 2009. The increase was a result of the same factors that affected earnings.

Operating Earnings

($ millions)



Volumes

Total sales of refined petroleum products averaged 82,200 cubic metres per day during the first quarter of 2010 compared to 31,400 cubic metres per day during the first quarter of 2009. Sales volumes were positively impacted by the merger through Suncor acquiring additional refining assets, national retail and wholesale businesses and an international lubricants business.

Overall refinery utilization averaged 92% in the first quarter of 2010, with utilization of the legacy Suncor refineries averaging 93% compared to 90% over the same period in 2009.

Three months ended March 31 (thousands of cubic metres per day)	**2010**	2009
Eastern North America		
Gasoline	**23.5**	8.2
Distillate	**14.0**	5.1
	37.5	13.3
Western North America		
Gasoline	**14.8**	8.2
Distillate	**14.4**	5.4
	29.2	13.6
Other	**15.5**	4.5
Total	**82.2**	31.4

Margins

Cracking margins declined quarter-over-quarter, resulting in a negative impact to operating earnings. In particular, distillate cracking margins were weaker, at US$8.35 per barrel for the first quarter of 2010, in comparison to US$14.20 per barrel for the same period in 2009, which had a significant impact on overall realized margins.

Operating Expenses

Operating expenses were $256 million higher in the first quarter of 2010 compared to the first quarter of 2009, which is a result of the merger. In April 2010, an arbitration panel awarded damages against Suncor relating to a claim made by Greenfield Ethanol Inc. The amount awarded and recorded in the first quarter results was $14 million, plus additional costs that Suncor is unable to quantify at this time.

Planned Turnarounds

Turnarounds are planned for the Edmonton, Montreal and Sarnia refineries in the second quarter of 2010. In October 2010, there is a turnaround planned for the lubricants plant. As with all planned turnarounds, the company enters into transactions to ensure sufficient additional finished product is available to mitigate the impact of lost production on customers.

Risk Factors Affecting Performance

The financial and operating performance of the company's Refining and Marketing business is potentially affected by a number of factors, including, but not limited to, the following:

- Production reliability risk. Our ability to reliably operate our refining and marketing facilities in order to meet production targets.
- Management expects that fluctuations in demand and supply for refined products, margin and price volatility, and market competition, including potential new market entrants, will continue to impact the business environment.
- There are certain risks associated with the execution of capital projects, including the risk of cost overruns. Numerous risks and uncertainties can affect construction schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period.
- Our relationship with our trade unions. Hourly employees at our London, Ontario terminal operation, our Sarnia, Ontario refinery, our Commerce City, Colorado refinery, our Montreal refinery, certain of our lubricants operations, certain of our terminalling operations and at Sun-Canadian Pipeline Company Limited are represented by labour unions or employee associations. Any work interruptions involving our employees, and/or contract trades utilized in our projects or operations, could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Additional risks, assumptions and uncertainties are discussed on page 31 under Forward-Looking Information.

Corporate, Energy Trading and Eliminations

Corporate, Energy Trading and Eliminations includes the company's investment in renewable energy projects, results related to third-party energy supply and trading activities and other activities not directly attributable to any other operating segment.

Three months ended March 31 ($ millions, unless otherwise noted)	**2010**	2009
Net earnings (loss)		
Renewable energy	**15**	10
Energy trading	**(11)**	28
Corporate	**10**	(208)
Group eliminations	**3**	(11)
	17	(181)
Operating earnings (loss) (1)		
Renewable energy	**15**	10
Energy trading	**(11)**	28
Corporate	**(233)**	(41)
Group eliminations	**3**	(11)
	(226)	(14)
Cash flow from (used in) operations (1)	**(314)**	63

(1) Non-GAAP measure. See page 30.

Renewable Energy

The company's renewable energy interests include four wind power projects and Canada's largest ethanol plant by production volume. Suncor's four wind projects, located in Saskatchewan, Alberta and Ontario, have a total generating capacity of 147 megawatts, offsetting the equivalent of 284,000 tonnes of carbon dioxide (CO_2) per year. The ethanol plant has a current capacity of 200 million litres per year, offsetting the equivalent of 300,000 tonnes of CO_2 per year. A $120 million expansion of the plant is currently underway, estimated to be complete by the end of 2010, with a planned doubling of production capacity. Net earnings of $15 million were contributed from the company's renewable energy operations in the first quarter of 2010, compared to $10 million for the same period in 2009, due primarily to the receipt of retroactive government contributions received in March 2010.

Energy Trading

Suncor's energy trading activities involve marketing and trading of crude oil, natural gas, refined products and by-products, and the use of financial derivatives. These activities resulted in a net loss of $11 million in the first quarter of 2010, compared to net earnings of $28 million in the first quarter of 2009.

The first quarter of 2010 has been negatively impacted by unrealized losses on physical trading strategies. In first quarter of 2009, results were positively impacted by realized gains on physical trading strategies in place to take advantage of rising crude oil prices.

Corporate and Eliminations

Corporate experienced an operating loss of $233 million in the first quarter of 2010, compared to an operating loss of $41 million operating loss in the first quarter of 2009. The increase was primarily the result of captive insurance expenses related to the December 2009 Oil Sands upgrader fire and increased net interest expense, due to additional debt acquired through the merger.

Group eliminations reflects the elimination of profit on crude oil sales between upstream segments and Refining and Marketing, where this crude oil still resides in Refining and Marketing's inventories. During the first quarter of 2010, $3 million of profits previously eliminated were recovered, compared to profits of $11 million that were eliminated in the first quarter of 2009.

Corporate, energy trading and eliminations net earnings were $17 million in the first quarter of 2010, compared with a $181 million net loss in the first quarter of 2009. The increase was primarily due to a $230 million after-tax foreign exchange gain related to U.S. dollar denominated long-term debt in the first quarter of 2010, compared to an after-tax loss of $148 million in the first quarter of 2009 due to the strengthening of the Canadian dollar relative to the U.S. dollar and higher levels of U.S. debt, as a result of the merger.

CASH INCOME TAXES

The company estimates that it will have cash income taxes of approximately $900 million to $1 billion during 2010. Cash income taxes are sensitive to crude oil and natural gas commodity price volatility and the timing of deductibility of capital expenditures for income tax purposes, among other things. This estimate is based on the following assumptions: current forecasts of production, capital and operating costs and the commodity prices and exchange rates described in the royalty estimate tables on pages 12 and 19, assuming there are no changes to the current income tax regime. The company's 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 this outlook. For further information related to risk factors that could affect this estimate; refer to pages 54 to 62 of the 2009 AIF.

FINANCIAL CONDITION AND LIQUIDITY

($ millions, except ratios)	March 31 2010	December 31 2009
Working capital (deficit)[1]	**616**	(315)
Short-term debt	**2**	2
Current portion of long-term debt	**39**	25
Long-term debt	**13 730**	13 855
Total debt	**13 771**	13 882
Less: Cash and equivalents	**602**	505
Net Debt	**13 169**	13 377
Shareholders' equity	**34 273**	34 111
Total capitalization (total debt & shareholders' equity)	**48 044**	47 993

	Three months ended March 31	
	2010	2009
Return on capital employed (%)[2],[3]	**4.9**	16.0
Return on capital employed (%)[2],[4]	**3.3**	11.3
Net debt to cash flow from operations (times)[5]	**4.2**	2.3
Interest coverage on long-term debt (times)		
Net earnings[6]	**4.9**	4.8
Cash flow from operations[7]	**7.2**	10.4
Debt to debt plus shareholders' equity (%)[8]	**28.7**	38.7

(1) Calculated as current assets less current liabilities, excluding cash and cash equivalents, short-term debt, current portion of long-term debt and future income taxes. Current assets and liabilities of discontinued operations are excluded.

(2) Non-GAAP measure. See page 30.

(3) Excludes capitalized costs related to major projects in progress.

(4) Includes capitalized costs related to major projects in progress.

(5) 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.

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

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

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

Capital Structure

Suncor's capital resources consist primarily of cash flow from operations and available lines of credit. Management of debt levels continues to be a priority given the company's long-term growth plans. Suncor's management believes a phased and flexible approach to existing and future growth projects should assist Suncor in maintaining its ability to manage project costs and debt levels.

At March 31, 2010, Suncor's net debt was $13.2 billion, compared to $13.4 billion at December 31, 2009. Undrawn lines of credit at March 31, 2010 were approximately $3.9 billion compared to $4.2 billion at December 31, 2009. During the first quarter of 2010, the company reduced a committed bilateral credit facility from $61 million to $15 million and reduced a demand credit facility from $175 million to $50 million.

Suncor's management believes it will have the capital resources to fund its planned capital spending program and to meet current working capital requirements through cash flow from operations and its committed credit facilities, assuming current production outlooks and other business plan assumptions are met. The company's 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 foreign exchange rates. If additional capital is required, the company believes adequate additional financing will be available in the debt capital markets at commercial terms and rates.

Suncor is subject to financial and operating covenants related to its 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. The company is in compliance with its financial covenant that requires total debt to not be more than 60% of its total capitalization. At March 31, 2010, total debt to total capitalization was 29% (December 31, 2009 – 29%). The company is also in compliance with all operating covenants.

The preceding paragraphs contain forward-looking information regarding our liquidity and capital resources based on factors and assumptions discussed above and on page 31. Users of this information are cautioned that our actual liquidity and capital resources may vary materially.

Outstanding Shares

At March 31, 2010	thousands
Common shares	1 561 104
Common share options – total	73 892

Credit Ratings

The company's debt ratings have not changed from December 31, 2009. For further information refer to page 13 of Suncor's 2009 Annual Report.

Contractual Obligations, Commitments and Guarantees

In the normal course of business, the company is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable. Suncor has included these obligations and commitments and guarantees in its 2009 Annual Report. There have been no significant developments since December 31, 2009.

Significant Capital Project Update

Suncor spent $1.1 billion on capital and exploration in the first quarter of 2010, out of a Board approved budget of $5.5 billion for 2010. A summary of the progress on significant projects under construction to support both growth and sustaining needs is provided below. All projects listed below have received Board approval. The estimates and target completion dates do not include project commissioning and start-up.

Project	Business Segment	Plan	Cost Estimate $ millions (1)	Estimate % Accuracy (1)	Spent to date	Target completion date
Ebla gas project	International and Offshore	Development of gas fields and construction of gas treatment plant	1 196	+7/− 3	1 091	Q2 2010 (2)
Buzzard enhancement project (3)	International and Offshore	Installation of equipment to handle high sulphur content	339	+15/− 10	176	Q4 2010
Firebag Stage 3	Oil Sands	Expansion is expected to increase bitumen supply	3 638	+10/− 10	3 007	Q2 2011
Naphtha unit	Oil Sands	Increases sweet product mix	850	+4/− 4	678	Q3 2011
North Amethyst (3)	International and Offshore	Extension to the White Rose field involving sub-sea tie-in	490	+10/− 5	294	2012 (4)

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

(2) Commercial production began in April 2010.

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

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

The company continues to incur costs related to placing certain growth projects into "safe mode" due to market conditions last 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 certain projects into safe mode, pre-tax costs of $40 million were incurred in the first quarter of 2010. Safe mode costs of approximately $150 million to $200 million on a pre-tax basis, including costs related to the remobilization of growth projects placed into safe mode, are expected to be incurred in 2010.

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 53 of Suncor's 2009 AIF.

FINANCIAL INSTRUMENTS

Suncor periodically enters 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. The company also uses physical and financial energy derivatives to earn trading revenues.

Suncor accounts for its significant derivative financial instruments using the mark-to-market method. The contracts are recorded on the balance sheet at fair value at each period end, with any changes in fair value immediately recognized in net earnings.

To estimate fair value of financial instruments, the company uses quoted market prices when available, or models that utilize observable market data. In addition to market information, Suncor incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. Inputs used are characterized in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The fair values of the company's derivative financial instruments are as follows:

($ millions)	**March 31 2010**	December 31 2009
Assets	**168**	213
Liabilities	**(447)**	(572)
Net derivative financial instruments	**(279)**	(359)

For further details on the company's derivative financial instruments at March 31, 2010, see note 5 to the March 31, 2010 unaudited interim Consolidated Financial Statements. For a more complete discussion of Suncor's exposure to financial risks and the company's mitigation activities, see note 5 to the 2009 Audited Consolidated Financial Statements.

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

The company's financial and operational performance is potentially affected by a number of factors including, but not limited to, commodity prices and foreign currency exchange rates, environmental regulations, changes to royalty and income tax legislation, credit market conditions, stakeholder support for activities and growth plans, extreme weather, regional labour issues and other issues discussed within Risk Factors Affecting Performance for each of Suncor's business segments. A more detailed discussion of the company's risk factors is presented on pages 54 to 62 of the 2009 AIF, filed with securities regulatory authorities. The company is continually working to mitigate the impact of potential risks to its stakeholders. This process includes an entity-wide risk review. This internal review is completed annually to ensure all significant risks are identified and appropriately managed.

Environmental Regulation and Risk

Environmental regulation affects nearly all aspects of our operations. These regulatory regimes are laws of general application that apply to us in the same manner as they apply to other companies and enterprises in the energy industry. The regulatory regimes require us to obtain operating licenses and permits in order to operate, and impose certain standards and controls on activities relating to mining, oil and gas exploration, development and production, and the refining, distribution and marketing of petroleum products and petrochemicals. Environmental assessments and regulatory approvals are generally required before initiating most new projects or undertaking significant changes to existing operations. In addition to these specific, known requirements, we expect future changes to environmental legislation, including anticipated legislation for air emissions (Criteria Air Contaminants (CACs) and Greenhouse Gases (GHGs)), will impose further requirements on companies operating in the energy industry.

For further discussion of environmental regulation and risks affecting the company, see page 21 in Suncor's 2009 Annual Report.

CRITICAL ACCOUNTING ESTIMATES

Critical accounting estimates are defined as estimates that are important to the portrayal of the company's financial position and operations, and require management to make judgments based on underlying assumptions about future events and their effects. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as the company's operating environment changes. Critical accounting estimates are reviewed annually by the Audit Committee of the Board of Directors. A detailed description of the critical accounting estimates used in the preparation of the March 31, 2010 unaudited interim Consolidated Financial Statements is presented on pages 23 to 25 of the 2009 Annual Report.

ACCOUNTING POLICIES

International Financial Reporting Standards

The following is a status update of the company's international financial reporting standards (IFRS) conversion project. A description of key activities, milestones and IFRS accounting policies selected are presented on pages 30 to 32 of the 2009 Annual Report. The major accounting policy choices outlined in the 2009 Annual Report should not be regarded as a complete list of changes that will result from the transition to IFRS. It is intended to highlight those areas the company believes to be most significant; however, analysis of changes will be ongoing throughout 2010. Note that new and revised IFRS developments will be monitored throughout the project and may result in changes to the project activities.

Financial Statement Preparation Preparation of the IFRS January 1, 2010 opening Balance Sheet has commenced and is to be presented to the Audit Committee during the second quarter of 2010. Preparation of draft disclosures is ongoing.

Training Training and communication sessions continued for the Board of Directors, senior management, finance and business personnel in the first quarter of 2010.

Infrastructure IFRS Information Technology (IT) Assessment is ongoing. This includes testing of the dual reporting IFRS IT solution and developing the 2011 conversion plan. Implementation of business process changes are underway.

Control Environment The Company's analysis to date supports a preliminary assessment that no material changes will be required to internal controls or disclosure controls over financial reporting. A detailed review of the control environment is to commence in the second quarter of 2010.

Control Environment

Based on their evaluation as of March 31, 2010, Suncor's chief executive officer and chief financial officer concluded that the company's 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 the company in reports that are filed or submitted to Canadian and U.S. securities authorities is recorded, processed, summarized and reported within the time periods specified in Canadian and U.S. securities laws. In addition, as of March 31, 2010, there were no changes in the internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) – 15d-15(f)) that occurred during the three-month period ended March 31, 2010 that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting. Management will continue to periodically evaluate the company's disclosure controls and procedures and internal control over financial reporting and will make any modifications from time to time as deemed necessary.

The company continues to integrate Petro-Canada's historical internal control over financial reporting with its internal control over financial reporting. This integration will lead to changes in these controls in future fiscal periods but it is not yet known whether these changes will materially affect internal control over financial reporting. This integration process is expected to be completed by the end of 2010.

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

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 cash and total operating costs are not prescribed by Canadian 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. These non-GAAP financial measures are included 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 Canadian GAAP.

Operating Earnings

Operating earnings is a non-GAAP measure that the company uses to evaluate operating performance, which management believes allows better comparability between periods. Operating earnings is calculated by adjusting net earnings for significant one-time items and items that are not indicative of operating performance. All reconciling items presented on an after-tax basis.

A reconciliation of after-tax net earnings to after-tax operating earnings is presented in the following table:

Three months ended March 31 ($ millions)	Oil Sands 2010	Oil Sands 2009	Natural Gas 2010	Natural Gas 2009	International and Offshore 2010	International and Offshore 2009	Refining and Marketing 2010	Refining and Marketing 2009	Corporate, Energy Trading and Eliminations 2010	Corporate, Energy Trading and Eliminations 2009	Total 2010	Total 2009
Net earnings (loss) from continuing operations as reported	**76**	(110)	**34**	(13)	**209**	—	**139**	112	**17**	(181)	**475**	(192)
Change in fair value of commodity derivatives used for risk management(1)	**(8)**	266	**—**	—	**—**	—	**—**	—	**—**	—	**(8)**	266
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**—**	—	**(230)**	148	**(230)**	148
Mark-to-market valuation of stock-based compensation	**(2)**	1	**(7)**	—	**(5)**	—	**(8)**	(1)	**(29)**	19	**(51)**	19
Project start-up costs	**8**	11	**—**	—	**1**	—	**—**	—	**—**	—	**9**	11
Costs related to deferral of growth projects	**30**	125	**—**	—	**—**	—	**—**	—	**—**	—	**30**	125
Merger and integration costs	**—**	—	**—**	—	**—**	—	**—**	—	**16**	—	**16**	—
Gains on significant disposals	**—**	—	**(27)**	—	**—**	—	**—**	—	**—**	—	**(27)**	—
Operating earnings (loss) from continuing operations	**104**	293	**—**	(13)	**205**	—	**131**	111	**(226)**	(14)	**214**	377
Net earnings from discontinued operations as reported	**—**	—	**187**	3	**54**	—	**—**	—	**—**	—	**241**	3
Gains on disposals of discontinued operations	**—**	—	**(168)**	—	**—**	—	**—**	—	**—**	—	**(168)**	—
Operating earnings (loss) from total operations	**104**	293	**19**	(10)	**259**	—	**131**	111	**(226)**	(14)	**287**	380

(1) The company adjusts operating earnings for the change in fair value of significant crude oil risk management derivatives. The company also holds less significant risk management derivatives in other segments which are not adjusted for.

Return on Capital Employed (ROCE)

ROCE is included because investors may use this information to analyze operating performance, leverage and liquidity. A detailed numerical reconciliation of ROCE is provided on an annual basis in the company's annual MD&A, which is to be read in conjunction with the company's annual Consolidated Financial Statements. For a summarized narrative reconciliation of ROCE calculated on a March 31, 2010 interim basis, please refer to page 50.

Cash Flow from Operations

Cash flow from operations is included because investors may use this information to analyze operating performance. Cash flow from operations is expressed before changes in non-cash working capital.

Three months ended March 31 ($ millions)	Oil Sands 2010	Oil Sands 2009	Natural Gas 2010	Natural Gas 2009	International and Offshore 2010	International and Offshore 2009	Refining and Marketing 2010	Refining and Marketing 2009	Corporate, Energy Trading and Eliminations 2010	Corporate, Energy Trading and Eliminations 2009	Total 2010	Total 2009
Total cash flow from (used in) operating activities	**(812)**	(877)	**195**	56	**557**	—	**128**	(30)	**198**	1 128	**266**	277
Less: Decrease (increase) in non-cash working capital related to continuing operating activities	**(1 074)**	(1 357)	**(32)**	—	**(35)**	—	**(200)**	(235)	**512**	1 065	**(829)**	(527)
Less: Decrease (increase) in non-cash working capital related to discontinued operating activities	**—**	—	**30**	3	**(59)**	—	**—**	—	**—**	—	**(29)**	3
Total cash flow from (used in) operations	**262**	480	**197**	53	**651**	—	**328**	205	**(314)**	63	**1 124**	801

Cash Operating Costs

Operating cost information is included because investors may use this information to analyze operating performance.

The following tables outline the reconciliation of Oil Sands expenses included in the Schedules of Segmented Data in the March 31, 2010 unaudited interim Consolidated Financial Statements to total and per barrel cash operating costs, total cash operating costs and total operating costs:

Oil Sands Operating Costs – Total Operations(1)

Three months ended March 31	**2010**		2009	
	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses	**1 118**		938	
Less: Natural gas costs, inventory changes, stock-based compensation, and other	**(122)**		3	
Less: Safe mode costs	**(40)**		(175)	
Less: Non-monetary transactions	**(14)**		(26)	
Less: Syncrude-related operating, selling and general expenses	**(122)**		—	
Accretion of asset retirement obligations	**27**		27	
Cash costs	**847**	**46.50**	767	30.65
Natural gas	**98**	**5.40**	75	3.00
Imported bitumen (excluding other reported product purchases)	**54**	**2.95**	1	0.05
Cash operating costs	**999**	**54.85**	843	33.70
Project start-up costs	**10**	**0.55**	16	0.65
Total cash operating costs	**1 009**	**55.40**	859	34.35
Depreciation, depletion and amortization	**230**	**12.65**	183	7.30
Total operating costs	**1 239**	**68.05**	1 042	41.65
Production excluding Syncrude (thousands of barrels per day)	**202.3**		278.0	

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

Legal 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 2010 outlook, see pages 3 to 5 of our first quarter 2010 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; effective execution of planned turnaround; 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 businesses after the merger; 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 Annual Information Form/Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission (SEC) at www.sec.gov. Readers are also referred to the risk factors described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

Consolidated Statements of Earnings

(unaudited)

($ millions)	Three months ended March 31 2010	2009
Revenues		
Operating revenues from continuing operations	**7 150**	2 473
Less: Royalties	**(459)**	(25)
Operating revenues (net of royalties)	**6 691**	2 448
Energy supply and trading activities	**344**	2 168
Interest and other income	**8**	—
	7 043	4 616
Expenses		
Purchases of crude oil and products	**3 230**	925
Operating, selling and general	**1 822**	1 195
Energy supply and trading activities	**362**	2 120
Transportation	**148**	61
Depreciation, depletion and amortization	**850**	295
Accretion of asset retirement obligations	**46**	28
Exploration	**46**	7
Loss (gain) on disposal of assets	**(24)**	17
Project start-up costs	**12**	16
Financing expenses (income) (note 6)	**(190)**	199
	6 302	4 863
Earnings (Loss) Before Income Taxes	**741**	(247)
Provisions for (Recovery of) Income Taxes (note 7)		
Current	**168**	90
Future	**98**	(145)
	266	(55)
Net earnings (loss) from continuing operations	**475**	(192)
Net earnings from discontinued operations (note 4)	**241**	3
Net Earnings (Loss)	**716**	(189)
Net Earnings (Loss) From Continuing Operations per Common Share (dollars), (note 4)		
Basic	**0.30**	(0.20)
Diluted	**0.30**	(0.20)
Net Earnings (Loss) per Common Share (dollars), (note 8)		
Basic	**0.46**	(0.20)
Diluted	**0.46**	(0.20)
Cash dividends	**0.10**	0.05

Consolidated Statements of Comprehensive Income

(unaudited)

($ millions)	Three months ended March 31 2010	2009
Net earnings (loss)	**716**	(189)
Other comprehensive income (loss), net of tax		
Change in foreign currency translation adjustment	**(429)**	32
Gain on derivative contracts designated as cash flow hedges	**—**	2
Comprehensive Income (Loss)	**287**	(155)

Consolidated Balance Sheets

(unaudited)

($ millions)	March 31 2010	December 31 2009
Assets		
Current assets		
Cash and cash equivalents	**602**	505
Accounts receivable	**4 263**	3 725
Inventories	**3 019**	2 947
Income taxes receivable	**525**	587
Future income taxes	**362**	332
Assets of discontinued operations (note 4)	**289**	235
Total current assets	**9 060**	8 331
Property, plant and equipment, net	**54 473**	54 890
Other assets	**470**	491
Goodwill	**3 201**	3 201
Future income taxes	**2**	193
Assets of discontinued operations (note 4)	**1 739**	2 640
Total assets	**68 945**	69 746
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**2**	2
Current portion of long-term debt (note 12)	**39**	25
Accounts payable and accrued liabilities	**6 040**	6 320
Income taxes payable	**1 151**	1 254
Future income taxes	**26**	18
Liabilities of discontinued operations (note 4)	**201**	229
Total current liabilities	**7 459**	7 848
Long-term debt (note 12)	**13 730**	13 855
Accrued liabilities and other	**4 480**	4 518
Future income taxes	**8 155**	8 367
Liabilities of discontinued operations (note 4)	**848**	1 047
Shareholders' equity (see below)	**34 273**	34 111
Total liabilities and shareholders' equity	**68 945**	69 746

Shareholders' Equity

	Number (thousands)		Number (thousands)	
Share capital	**1 561 104**	**20 076**	1 559 778	20 053
Contributed surplus		**534**		526
Accumulated other comprehensive income (loss) (note 14)		**(662)**		(233)
Retained earnings		**14 325**		13 765
Total shareholders' equity		**34 273**		34 111

Consolidated Statements of Cash Flows

(unaudited)

($ millions)	Three months ended March 31 2010	2009
Operating Activities		
Net earnings (loss) from continuing operations	**475**	(192)
Adjustments for:		
Depreciation, depletion and amortization	**850**	295
Future income taxes	**98**	(145)
Accretion of asset retirement obligations	**46**	28
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(260)**	148
Change in fair value of derivative contracts	**(80)**	656
Loss (gain) on disposal of assets	**(24)**	17
Stock-based compensation	**(77)**	55
Other	**(44)**	(74)
Exploration expenses	**15**	—
Increase in non-cash working capital related to operating activities (note 9)	**(829)**	(527)
Cash flow provided by continuing operations	**170**	261
Cash flow provided by discontinued operations	**96**	16
Cash flow from operating activities	**266**	277
Investing Activities		
Capital and exploration expenditures	**(1 048)**	(1 087)
Other investments	**—**	(17)
Proceeds from disposals	**57**	—
Decrease (increase) in non-cash working capital related to investing activities	**5**	(393)
Cash flow used in continuing investing activities	**(986)**	(1 497)
Cash flow from (used in) discontinued investing activities	**807**	(19)
Total cash flow used in investing activities	**(179)**	(1 516)
Net cash surplus (deficiency) before financing activities	**87**	(1 239)
Financing Activities		
Increase in short-term debt	**—**	1
Net increase in revolving-term debt	**151**	1 037
Issuance of common shares under stock option plan	**15**	15
Dividends paid on common shares	**(153)**	(47)
Cash flow provided by financing activities	**13**	1 006
Increase (Decrease) in Cash and Cash Equivalents	**100**	(233)
Effect of Foreign Exchange on Cash and Cash Equivalents	**(3)**	4
Cash and Cash Equivalents at Beginning of Period	**505**	660
Cash and Cash Equivalents at End of Period	**602**	431

Consolidated Statements of Changes in Shareholders' Equity

(unaudited)

($ millions)	Share Capital	Contributed Surplus	Accumulated Other Comprehensive Income (Loss)	Retained Earnings
At December 31, 2008	1 113	288	97	13 025
Net loss	—	—	—	(189)
Dividends paid on common shares	—	—	—	(47)
Issued for cash under stock option plan	18	(3)	—	—
Stock-based compensation expense	—	27	—	—
Income tax benefit of stock option deduction in the U.S.	—	3	—	—
Change in accumulated other comprehensive income (loss)	—	—	34	—
At March 31, 2009	1 131	315	131	12 789
At December 31, 2009	20 053	526	(233)	13 765
Net earnings	**—**	**—**	**—**	**716**
Dividends paid on common shares	**—**	**—**	**—**	**(153)**
Issued for cash under stock option plans	**20**	**(5)**	**—**	**—**
Issued under dividend reinvestment plan	**3**	**—**	**—**	**(3)**
Stock-based compensation expense	**—**	**13**	**—**	**—**
Change in accumulated other comprehensive income (loss)	**—**	**—**	**(429)**	**—**
At March 31, 2010	**20 076**	**534**	**(662)**	**14 325**

Schedule of Segmented Data from Continuing Operations

(unaudited)

Three months ended March 31

($ millions)	Oil Sands 2010	Oil Sands 2009	Natural Gas 2010	Natural Gas 2009	International and Offshore 2010	International and Offshore 2009	Refining and Marketing 2010	Refining and Marketing 2009	Corporate, Energy Trading and Eliminations 2010	Corporate, Energy Trading and Eliminations 2009	Total 2010	Total 2009
EARNINGS												
Revenues												
Operating revenues from continuing operations	**934**	937	**328**	76	**1 074**	—	**4 723**	1 413	**91**	47	**7 150**	2 473
Less: Royalties	**(70)**	(8)	**(53)**	(17)	**(336)**	—	**—**	—	**—**	—	**(459)**	(25)
Operating revenues (net of royalties)	**864**	929	**275**	59	**738**	—	**4 723**	1 413	**91**	47	**6 691**	2 448
Energy supply and trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**344**	2 168	**344**	2 168
Intersegment revenues	**870**	171	**16**	15	**131**	—	**86**	—	**(1 103)**	(186)	**—**	—
Interest and other income	**166**	—	**—**	—	**(1)**	—	**—**	—	**(157)**	—	**8**	—
	1 900	1 100	**291**	74	**868**	—	**4 809**	1 413	**(825)**	2 029	**7 043**	4 616
Expenses												
Purchases of crude oil and products	**290**	62	**—**	—	**54**	—	**3 935**	1 012	**(1 049)**	(149)	**3 230**	925
Operating, selling and general	**1 118**	938	**78**	39	**59**	—	**507**	176	**60**	42	**1 822**	1 195
Energy supply and trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**362**	2 120	**362**	2 120
Transportation	**63**	57	**20**	4	**26**	—	**45**	4	**(6)**	(4)	**148**	61
Depreciation, depletion and amortization	**269**	183	**163**	49	**290**	—	**118**	53	**10**	10	**850**	295
Accretion of asset retirement obligations	**30**	27	**9**	1	**6**	—	**1**	—	**—**	—	**46**	28
Exploration	**5**	6	**11**	1	**30**	—	**—**	—	**—**	—	**46**	7
Loss (gain) on disposal of assets	**9**	17	**(36)**	—	**—**	—	**3**	—	**—**	—	**(24)**	17
Project start-up costs	**10**	16	**—**	—	**2**	—	**—**	—	**—**	—	**12**	16
Financing expenses (income)	**—**	—	**—**	—	**(6)**	—	**4**	—	**(188)**	199	**(190)**	199
	1 794	1 306	**245**	94	**461**	—	**4 613**	1 245	**(811)**	2 218	**6 302**	4 863
Earnings (loss) before income taxes	**106**	(206)	**46**	(20)	**407**	—	**196**	168	**(14)**	(189)	**741**	(247)
Income taxes	**(30)**	96	**(12)**	7	**(198)**	—	**(57)**	(56)	**31**	8	**(266)**	55
Net earnings (loss) from continuing operations	**76**	(110)	**34**	(13)	**209**	—	**139**	112	**17**	(181)	**475**	(192)

	Oil Sands Mar 31 2010	Oil Sands Dec 31 2009	Natural Gas Mar 31 2010	Natural Gas Dec 31 2009	International and Offshore Mar 31 2010	International and Offshore Dec 31 2009	Refining and Marketing Mar 31 2010	Refining and Marketing Dec 31 2009	Corporate, Energy Trading and Eliminations Mar 31 2010	Corporate, Energy Trading and Eliminations Dec 31 2009	Total Mar 31 2010	Total Dec 31 2009
TOTAL ASSETS – continuing operations	**38 386**	37 553	**3 973**	4 083	**12 274**	12 729	**11 523**	10 304	**761**	2 202	**66 917**	66 871

Schedule of Segmented Data from Continuing and Discontinued Operations

(unaudited)

	Three months ended March 31											
	Oil Sands		Natural Gas		International and Offshore		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
($ millions)	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009
CASH FLOW BEFORE FINANCING ACTIVITIES												
Operating activities:												
Net earnings (loss) from continuing operations	**76**	(110)	**34**	(13)	**209**	—	**139**	112	**17**	(181)	**475**	(192)
Adjustments for:												
Depreciation, depletion and amortization	**269**	183	**163**	49	**290**	—	**118**	53	**10**	10	**850**	295
Future income taxes	**27**	(222)	**13**	4	**29**	—	**58**	41	**(29)**	32	**98**	(145)
Accretion of asset retirement obligations	**30**	27	**9**	1	**6**	—	**1**	—	**—**	—	**46**	28
Unrealized (gain) loss on translation of U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**—**	—	**(260)**	148	**(260)**	148
Change in fair value of derivative contracts	**(67)**	646	**—**	—	**—**	—	**—**	(6)	**(13)**	17	**(80)**	657
Loss (gain) on disposal of assets	**9**	17	**(36)**	—	**—**	—	**3**	—	**—**	—	**(24)**	17
Stock-based compensation	**8**	16	**(9)**	1	**2**	—	**(9)**	2	**(69)**	36	**(77)**	55
Other	**(90)**	(77)	**(4)**	(2)	**2**	—	**18**	3	**30**	1	**(44)**	(75)
Exploration expenses	**—**	—	**12**	—	**3**	—	**—**	—	**—**	—	**15**	—
Decrease (increase) in non-cash working capital related to operating activities	**(1 074)**	(1 357)	**(32)**	—	**(35)**	—	**(200)**	(235)	**512**	1 065	**(829)**	(527)
Total cash flow from (used in) operating activities from continuing operations	**(812)**	(877)	**150**	40	**506**	—	**128**	(30)	**198**	1 128	**170**	261
Total cash flow from (used in) operating activities from discontinued operations	**—**	—	**45**	16	**51**	—	**—**	—	**—**	—	**96**	16
Total cash flow from (used in) operating activities	**(812)**	(877)	**195**	56	**557**	—	**128**	(30)	**198**	1 128	**266**	277
Investing activities:												
Capital and exploration expenditures	**(691)**	(966)	**(40)**	(90)	**(231)**	—	**(66)**	(27)	**(20)**	(4)	**(1 048)**	(1 087)
Other investments	**—**	(16)	**—**	—	**—**	—	**—**	(1)	**—**	—	**—**	(17)
Proceeds from disposals	**7**	—	**40**	—	**7**	—	**3**	—	**—**	—	**57**	—
Decrease (increase) in investing working capital	**91**	(395)	**(6)**	—	**(79)**	—	**(1)**	—	**—**	2	**5**	(393)
Cash flow used in continuing investing activities	**(593)**	(1 377)	**(6)**	(90)	**(303)**	—	**(64)**	(28)	**(20)**	(2)	**(986)**	(1 497)
Cash flow from (used in) discontinued investing activities	**—**	—	**889**	(19)	**(82)**	—	**—**	—	**—**	—	**807**	(19)
Total cash from (used in) investing activities	**(593)**	(1 377)	**883**	(109)	**(385)**	—	**(64)**	(28)	**(20)**	(2)	**(179)**	(1 516)
Net cash surplus (deficiency) before financing activities	**(1 405)**	(2 254)	**1 078**	(53)	**172**	—	**64**	(58)	**178**	1 126	**87**	(1 239)

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. Certain information and disclosures normally required to be included in notes to the annual consolidated financial statements have been condensed or omitted.

In the opinion of management, these interim consolidated financial statements contain all adjustments of a normal and recurring nature necessary to present fairly Suncor Energy Inc.'s (Suncor) financial position at March 31, 2010 and the results of its operations and cash flows for the three month period ended March 31, 2010 and 2009.

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

2. BUSINESS COMBINATION WITH PETRO-CANADA

(a) Overview

On August 1, 2009, Suncor completed its merger with Petro-Canada. The company has accounted for this business combination as prescribed by CICA Handbook section 1581 "Business Combinations." As the acquirer, 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.

(b) Preliminary Allocation of Purchase Price

The following estimated 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	27 407
Other assets	537
Total assets	32 589
Current liabilities	3 741
Long-term debt	4 410
Accrued liabilities and other	3 416
Future income taxes	4 570
Total liabilities	16 137
Net assets purchased	16 452
Goodwill	3 178
Total purchase price	19 630

The preliminary purchase price allocation is based on current best estimates by Suncor's management and is based principally on valuations prepared by independent valuation specialists. During the first quarter of 2010, management did not amend this purchase price allocation.

The fair value for current liabilities includes $216 million for provisions for costs related to exiting certain activities of Petro-Canada and involuntary termination benefits. As at March 31, 2010, $132 million of actual expenses had been charged against these provisions.

3. CHANGE IN SEGMENTED DISCLOSURES

As a result of planned divestitures of the company's assets in Trinidad and Tobago, The Netherlands and certain assets in the United Kingdom (described in note 4), the company has combined its International and East Coast Canada segments into one new segment, International and Offshore. Continuing operations for the International and Offshore segment are comprised of activity offshore Newfoundland and Labrador, including interests in the Hibernia, Terra Nova, White Rose and Hebron oilfields, and the exploration for, and production of, crude oil and natural gas in the United Kingdom, Norway, Libya and Syria.

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

4. DISCONTINUED OPERATIONS

The company is divesting certain non-core assets as part of its continuing strategic alignment, with announced sales to date of approximately $1.5 billion. The proceeds of these sales are planned to go towards reducing the company's debt.

Natural Gas

On March 1, 2010, the company completed the sale of its oil and gas producing assets in the U.S. Rockies for net proceeds of US$481 million.

On March 31, 2010, the company completed the sale of certain non-core natural gas properties located in northeast British Columbia for net proceeds of $383 million.

On March 24, 2010, the company entered into an agreement to sell non-core assets in central Alberta (Rosevear and Pine Creek) for proceeds of $235 million. The sale is expected to close in the second quarter of 2010 and is subject to closing conditions and regulatory approvals typical of transactions of this nature.

International and Offshore

On February 25, 2010, Suncor entered into an agreement to sell its assets in Trinidad and Tobago for proceeds of US$380 million. The sale is expected to close in the second quarter of 2010 and is subject to customary closing conditions, Trinidad and Tobago government approval and other regulatory approvals.

Suncor has decided to divest certain non-core North Sea assets in the U.K. and The Netherlands, and these operations have been accounted for as discontinued operations. U.K. North Sea assets that are planned to be divested include Scott/Telford and Triton. The company expects to maintain its ownership positions in the producing Buzzard field, and exploration assets in the Hobby, Golden Eagle and Pink fields. At March 31, 2010, no agreement has been reached on the sale of these non-core North Sea assets.

Net income from discontinued operations reported in the Consolidated Statements of Earnings is as follows:

	Natural Gas		International and Offshore		Total	
					Three months ended March 31	
($ millions)	**2010**	2009	**2010**	2009	**2010**	2009
Revenues						
Operating revenues	**71**	23	**211**	—	**282**	23
Less: Royalties	**(13)**	(6)	**—**	—	**(13)**	(6)
Operating revenues (net of royalties)	**58**	17	**211**	—	**269**	17
Interest and other income	**—**	—	**3**	—	**3**	—
Gain on disposal of assets	**231**	—	**—**	—	**231**	—
	289	17	**214**	—	**503**	17
Expenses						
Operating, selling and general	**18**	3	**38**	—	**56**	3
Transportation	**2**	1	**8**	—	**10**	1
Depreciation, depletion and amortization	**6**	7	**56**	—	**62**	7
Accretion of asset retirement obligations	**1**	1	**6**	—	**7**	1
Exploration	**—**	—	**2**	—	**2**	—
Financing expenses	**7**	—	**1**	—	**8**	—
	34	12	**111**	—	**145**	12
Earnings before income taxes	**255**	5	**103**	—	**358**	5
Income taxes	**68**	2	**49**	—	**117**	2
Net earnings	**187**	3	**54**	—	**241**	3

	Three months ended March 31	
(dollars)	**2010**	2009
Basic earnings per share from discontinued operations	**0.16**	—
Diluted earnings per share from discontinued operations	**0.16**	—

The assets and liabilities of discontinued operations presented on the Consolidated Balance Sheets are as follows:

	Natural Gas		International and Offshore		Total	
	March 31	December 31	**March 31**	December 31	**March 31**	December 31
($ millions)	**2010**	2009	**2010**	2009	**2010**	2009
Assets						
Current assets	**3**	12	**286**	223	**289**	235
Property, plant and equipment, net	**130**	908	**1 609**	1 732	**1 739**	2 640
Total assets	**133**	920	**1 895**	1 955	**2 028**	2 875
Liabilities						
Current liabilities	**29**	51	**172**	178	**201**	229
Accrued liabilities and other	**38**	140	**370**	404	**408**	544
Future income taxes	**—**	31	**440**	472	**440**	503
Total liabilities	**67**	222	**982**	1 054	**1 049**	1 276

5. FINANCIAL INSTRUMENTS AND FINANCIAL RISK FACTORS

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

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

Physical trading commodity contracts that exceed the company's expected purchase, sale or usage requirements are accounted for as derivative financial instruments whereby realized and unrealized gains and losses, and the underlying settlement of these contracts is recognized and reported on a net basis in Energy Supply and Trading Activities revenue. The related inventory is carried at fair value less costs to sell, with changes in fair value recognized as gains or losses within Energy Supply and Trading Activities revenue.

(a) Balance Sheet Financial Instruments

The company's financial instruments in the Consolidated Balance Sheets consist of cash and cash equivalents, accounts receivable, derivative contracts, substantially all current liabilities, 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 characterizes inputs used in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable in the market (see page 77 of Suncor's 2009 Annual Report for further detail). As at March 31, 2010, there were no significant changes to the distribution of the fair value hierarchy used to value financial instruments.

The company's fixed-term debt is accounted for under the amortized cost method, with the exception of the portion of debt where future interest payments have been swapped from fixed to floating payments, which is accounted for at fair value. Upon initial recognition, the cost of the debt is its fair value, adjusted for any associated transaction costs. The company does not recognize gains or losses arising from changes in the fair value of this debt until the gains or losses are realized. Gains or losses on our U.S. dollar denominated long-term debt resulting from changes in the exchange rate are recognized in the period in which they occur. At March 31, 2010, the carrying value of our fixed-term debt accounted for under the amortized cost method was $9.9 billion (December 31, 2009 – $10.1 billion) and the fair value was $10.5 billion (December 31, 2009 – $10.7 billion).

(b) Hedge Accounting

For a detailed discussion of fair value and cash flow hedges, see page 75 of Suncor's 2009 Annual Report.

Fair Value Hedges

At March 31, 2010, the company had interest rate swaps classified as fair value hedges outstanding until August 2011, relating to fixed-rate debt. The fair value of these swaps totaled $12 million at March 31, 2010 (December 31, 2009 – $18 million), and was recorded in accounts receivable in the Consolidated Balance Sheets. There was no ineffectiveness recognized on these interest rate swaps during the three month periods ended March 31, 2010 and March 31, 2009.

Cash Flow Hedges

At March 31, 2010, the company had no outstanding cash flow hedges in place (December 31, 2009 – nil). There was no earnings impact associated with realized and unrealized hedge ineffectiveness on derivative contracts designated as cash flow hedges during the three month periods ended March 31, 2010 and March 31, 2009.

Accumulated Other Comprehensive Income (AOCI)

There was no significant change in AOCI attributable to hedge accounting in the first quarter of 2010. For a reconciliation of changes in AOCI attributable to hedge accounting for prior periods, see page 76 of Suncor's 2009 Annual Report.

(c) Other Derivatives

Risk Management Derivatives

The company periodically enters into derivative contracts which although not accounted for as hedges because they have not been documented as such or do not qualify under GAAP, are believed to be economically effective at mitigating our exposure to adverse commodity price movements and an important component of our overall risk management program. The earnings impact associated with these contracts for the three months period ended March 31, 2010, was a gain of $5 million, net of income taxes of $2 million (2009 – a loss of $148 million, net of income taxes of $59 million).

Significant contracts outstanding at March 31, 2010 were as follows:

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

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

(2) Total premium paid on outstanding contracts was US$22 million.

(3) Premium received on outstanding contracts was US$160 million.

Energy Trading Derivatives

The company's Energy Trading group also uses physical and financial energy contracts, including swaps, forwards and options to earn trading revenues. These energy contracts are comprised of crude oil, natural gas and refined products contracts.

The earnings impact associated with these contracts for the three months period ended March 31, 2010, was a gain of $18 million, net of income taxes of $7 million (2009 – a gain of $25 million, net of income taxes of $10 million).

Change in Fair Value of Other Derivatives

($ millions)	**Risk Management**	**Energy Trading**	**Total**
Fair value of contracts at December 31, 2009	(312)	(47)	(359)
Fair value of contracts realized during the period	50	(9)	41
Changes in fair value attributable to market price and other market changes during the period	14	25	39
Fair value of contracts outstanding at March 31, 2010 [a], [b]	**(248)**	**(31)**	**(279)**

(a) As at March 31, 2010, of the total unrealized derivatives $168 million is recorded in accounts receivable (December 31, 2009 – $213 million recorded in accounts receivable) in the Consolidated Balance Sheets.

(b) As at March 31, 2010, of the total unrealized derivatives $447 million is recorded in accounts payable and accrued liabilities (December 31, 2009 – $572 million).

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 activities, which are defined as strategic hedging, optimization trading, marketing and speculative trading. The RMC, acting under board authority, meets regularly to monitor limits on risk exposures, review policy compliance and validate risk-related methodologies and procedures. All risk management activity is carried out by specialist teams that have the appropriate skills, experience and supervision with the appropriate financial and management controls.

At March 31, 2010, the company's exposure to risks arising from the use of financial instruments had not changed significantly from December 31, 2009.

For a full discussion of the company's financial risk factors, see page 78 of Suncor's 2009 Annual Report.

6. FINANCING EXPENSES (INCOME)

	Three months ended March 31	
($ millions)	**2010**	2009
Interest on debt	**184**	118
Capitalized interest	**(76)**	(54)
Interest expense	**108**	64
Foreign exchange (gain) loss on long-term debt	**(260)**	148
Other foreign exchange gain	**(38)**	(13)
Total financing expenses (income) from continuing operations(1)	**(190)**	199

(1) $8 million (2009 – $nil) has been reclassified to net earnings from discontinued operations.

7. INCOME TAXES

	Three months ended March 31	
($ millions)	**2010**	2009
Provision for (recovery of) income taxes:		
Current:		
Canada	**3**	80
Foreign	**165**	10
Future:		
Canada	**88**	(160)
Foreign	**10**	15
Total provision (recovery) for income taxes from continuing operations(1)	**266**	(55)

(1) $117 million (2009 – $2 million) has been reclassified to net earnings from discontinued operations.

8. RECONCILIATION OF BASIC AND DILUTED EARNINGS (LOSS) PER COMMON SHARE

	Three months ended March 31	
($ millions)	**2010**	2009
Net earnings (loss)	**716**	(189)
(millions of common shares)		
Weighted-average number of common shares	**1 561**	936
Dilutive securities:		
Options issued under stock-based compensation plans	**12**	8
Weighted-average number of diluted common shares	**1 573**	944
(dollars per common share)		
Basic earnings per share(a)	**0.46**	(0.20)
Diluted earnings per share(b)	**0.46**	(0.20)

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. 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 from continuing operations is comprised of:

	Three months ended March 31	
($ millions)	**2010**	2009
Operating activities		
Accounts receivable	**(901)**	(148)
Inventories	**(66)**	(227)
Accounts payable and accrued liabilities	**170**	25
Taxes payable/receivable	**(32)**	(177)
	(829)	(527)

10. EMPLOYEE FUTURE BENEFITS LIABILITY

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

	Pension Benefits		**Other Post-Retirement Benefits**	
	Three months ended March 31		Three months ended March 31	
($ millions)	**2010**	2009	**2010**	2009
Current service costs	**22**	13	**2**	1
Interest costs	**42**	13	**6**	2
Expected return on plan assets	**(36)**	(10)	**—**	—
Amortization of net actuarial loss	**2**	5	**—**	—
Net periodic benefit cost	**30**	21	**8**	3

11. SHARE CAPITAL

Issued

	Number (thousands)	Common Shares Amount ($ millions)
Balance as at December 31, 2009	**1 559 778**	20 053
Issued for cash under stock option plans	**1 230**	20
Issued under dividend reinvestment plan	**96**	3
Balance as at March 31, 2010	**1 561 104**	20 076

Stock-Based Compensation

(a) Stock Option Plans

(i) Discontinued Plans

There are a number of legacy Suncor and legacy Petro-Canada plans that were in place prior to the merger on August 1, 2009, for which granting of options ended on July 31, 2009. For details of the terms and conditions of these plans, refer to pages 88 and 89 of Suncor's 2009 Annual Report.

(ii) Suncor Energy Inc. Stock Options

This plan replaced the pre-merger stock option plans of legacy Suncor and legacy Petro-Canada. Outstanding 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. The company granted 4,235,000 options with tandem stock appreciation rights under this plan during the first quarter of 2010. Options granted have a seven-year life and vest annually over a three-year period.

Changes in the number of outstanding stock options were as follows:

	Number (thousands)	Weighted-Average Exercise Price ($)
Outstanding, December 31, 2009	72 024	32.52
Granted	**4 235**	**31.85**
Exercised	**(1 213)**	**12.88**
Forfeited/expired	**(1 154)**	**41.39**
Outstanding, March 31, 2010	**73 892**	**32.36**

(b) Stock Appreciation Rights (SARs)

(i) Discontinued Plan

Legacy Petro-Canada had a SARs plan for which grants ended on July 31, 2009. For details of the terms and conditions of this plan, refer to page 90 of Suncor's 2009 Annual Report.

(ii) Suncor Energy Inc. Stock Appreciation Rights

The company granted 346,000 SARs under this new plan during the first quarter of 2010. These SARs have a seven-year life and vest annually over a three-year period.

Changes in the number of outstanding SARs were as follows:

	Number (thousands)	Weighted-Average Exercise Price ($)
Outstanding, December 31, 2009	14 065	28.63
Granted	**346**	**31.85**
Exercised	**(150)**	**21.78**
Forfeited/expired	**(637)**	**27.63**
Outstanding, March 31, 2010	**13 624**	**28.84**

(c) Share Unit Plans

For details of the terms and conditions of the Performance Share Unit (PSU), Restricted Share Unit (RSU) and Deferred Share Unit (DSU) plans, refer to page 91 of Suncor's 2009 Annual Report.

Changes in the number of outstanding units were as follows:

		Number (thousands)	
	PSU	RSU	DSU
Outstanding, December 31, 2009	3 247	4 250	428
Granted	**1 648**	**2 772**	**1 739**
Redeemed	**(271)**	**(6)**	**(33)**
Forfeited	**(726)**	**(81)**	**—**
Reinvested	**7**	**12**	**7**
Outstanding, March 31, 2010	**3 905**	**6 947**	**2 141**

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 March 31	
($ millions)	**2010**	2009
Stock option plans	**(22)**	27
SARs	**(18)**	—
PSUs	**(13)**	8
RSUs	**23**	13
DSUs	**(10)**	9
Total stock based compensation expense (recovery)	**(40)**	57

12. LONG-TERM DEBT AND CREDIT FACILITIES

($ millions)	**March 31 2010**	December 31 2009
Fixed-term debt, redeemable at the option of the company		
6.85% Notes, denominated in U.S. dollars, due in 2039 (US$750)	**762**	785
6.80% Notes, denominated in U.S. dollars, due in 2038 (US$900)	**943**	972
6.50% Notes, denominated in U.S. dollars, due in 2038 (US$1150)	**1 168**	1 204
5.95% Notes, denominated in U.S. dollars, due in 2035 (US$600)	**562**	578
5.95% Notes, denominated in U.S. dollars, due in 2034 (US$500)	**508**	523
5.35% Notes, denominated in U.S. dollars, due in 2033 (US$300)	**259**	266
7.15% Notes, denominated in U.S. dollars, due in 2032 (US$500)	**508**	523
6.10% Notes, denominated in U.S. dollars, due in 2018 (US$1250)	**1 270**	1 308
6.05% Notes, denominated in U.S. dollars, due in 2018 (US$600)	**623**	643
5.00% Notes, denominated in U.S. dollars, due in 2014 (US$400)	**415**	429
4.00% Notes, denominated in U.S. dollars, due in 2013 (US$300)	**303**	313
7.00% Debentures, denominated in U.S. dollars, due in 2028 (US$250)	**263**	271
7.875% Debentures, denominated in U.S. dollars, due in 2026 (US$275)	**315**	325
9.25% Debentures, denominated in U.S. dollars, due in 2021 (US$300)	**388**	402
5.39% Series 4 Medium Term Notes, due in 2037	**600**	600
5.80% Series 4 Medium Term Notes, due in 2018	**700**	700
6.70% Series 2 Medium Term Notes, due in 2011	**500**	500
	10 087	10 342
Revolving-term debt, with interest at variable rates		
Commercial paper, bankers' acceptances and LIBOR loans	**3 397**	3 244
Total unsecured long-term debt	**13 484**	13 586
Secured long-term debt	**13**	13
Capital leases	**322**	326
Fair value of interest swaps	**12**	18
Deferred financing costs	**(62)**	(63)
	13 769	13 880
Current portion of long-term debt		
Capital leases	**(30)**	(14)
Fair value of interest swaps	**(9)**	(11)
Total current portion of long-term debt	**(39)**	(25)
Total long-term debt	**13 730**	13 855

At March 31, 2010, undrawn lines of credit were $3,926 million, as follows:

($ millions)	2010
Facility that is fully revolving for 364 days, has a term period of one year and expires in 2010	**15**
Facility that is fully revolving for a period of four years and expires in 2013	**203**
Facilities that are 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	**464**
Total available credit facilities	**8 002**
Credit facilities supporting outstanding commercial paper, bankers' acceptances and LIBOR loans	**(3 397)**
Credit facilities supporting letters of credit	**(679)**
Total undrawn credit facilities	**3 926**

13. CAPITAL STRUCTURE FINANCIAL POLICIES

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

The company monitors capital through two key ratios: net debt to cash flow from operations[(1)] and total debt to total debt plus shareholders' equity.

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

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

Financial covenants associated with the company's various banking and debt arrangements are reviewed regularly and controls are in place to maintain compliance with these covenants. The company complied with all financial covenants for the period ended March 31, 2010 and December 31, 2009.

During the first quarter of 2010, the company's strategy 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 increase in debt levels as a result of the merger with Petro-Canada has caused our net debt/cash flow from operations measure to fall outside of management's target, as the calculation only includes eight months of cash flow from operations relating to legacy Petro-Canada operations.

At March 31, ($ millions)	Capital Measure Target	2010	2009
Components of ratios			
Short-term debt		**2**	2
Current portion of long-term debt		**39**	18
Long-term debt		**13 730**	9 049
Total debt		**13 771**	9 069
Cash and equivalents		**602**	431
Net debt		**13 169**	8 638
Shareholders' equity		**34 273**	14 366
Total capitalization (total debt + shareholders' equity)		**48 044**	23 435
Cash flow from operations[(1)] (trailing twelve months)		**3 122**	3 708
Net debt/cash flow from operations	<2.0 times	**4.2**	2.3
Total debt/total debt plus shareholders' equity		**29%**	39%

(1) Cash flow from operations is calculated as cash flow from operating activities before changes in non-cash working capital.

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

14. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

($ millions)	**March 31 2010**	December 31 2009
Unrealized foreign currency translation adjustment	**(677)**	(248)
Unrealized gains on derivative hedging activities	**15**	15
Total	**(662)**	(233)

15. SUPPLEMENTAL INFORMATION

	Three months ended March 31	
($ millions)	**2010**	2009
Interest paid	**89**	61
Income taxes paid	**231**	240

Highlights

(unaudited)

	2010	2009
Cash Flow From Operations		
(dollars per common share – basic)		
For the three months ended March 31		
Cash flow from operations (1)	**0.72**	0.86
Ratios		
For the twelve months ended March 31		
Return on capital employed (%) (2)	**4.9**	16.0
Return on capital employed (%) (3)	**3.3**	11.3
Net debt to cash flow from operations (times) (4)	**4.2**	2.3
Pro forma – Net debt to cash flow from operations (times) (5)	**3.4**	N/A
Interest coverage on long-term debt (times)		
Net earnings (6)	**4.9**	4.8
Cash flow from operations (7)	**7.2**	10.4
As at March 31		
Debt to debt plus shareholders' equity (%) (8)	**28.7**	38.7
Common Share Information		
As at March 31		
Share price at end of trading		
Toronto Stock Exchange – Cdn$	**33.03**	28.14
New York Stock Exchange – US$	**32.54**	22.21
Common share options outstanding (thousands)	**73 892**	46 620
For the twelve months ended March 31		
Average number outstanding, weighted monthly (thousands)	**1 560 744**	936 293

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 (2010 – $1,187 million; 2009 – $2,227 million) adjusted for after-tax financing income (2010 – $864 million; 2009 – expense of $987 million) divided by average capital employed (2010 – $24,350 million; 2009 – $13,941 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: 2010 – $36,071 million; 2009 – $19,757 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 to cash flow from operations measure to increase significantly, as the calculation only includes eight months of cash flow from operations relating to legacy Petro-Canada operations.

(5) Pro forma net debt to cash flow from operations is calculated by taking short-term debt plus long-term debt less cash and cash equivalents, divided by the sum of cash flow from operations for the twelve-month period ended March 31, 2010, plus cash flow from operations for legacy Petro-Canada operations for the four-month period ended July 31, 2009. Cash flow from operations for legacy Petro-Canada operations over this four-month period totalled $736 million.

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

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

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

Quarterly Operating Summary

(unaudited)

	Three months ended					Twelve months ended
	Mar 31 2010	Dec 31 2009	Sept 30 2009	June 30 2009	Mar 31 2009	Dec 31 2009
OIL SANDS						
Production [a]						
Total production (excluding Syncrude)	**202.3**	278.9	305.3	301.0	278.0	290.6
Firebag [k]	**55.7**	51.1	54.3	48.3	42.4	49.1
MacKay River [k]	**31.8**	31.7	26.5***	—	—	29.7***
Syncrude	**32.3**	39.3	37.4***	—	—	38.5***
Sales [a] (excluding Syncrude)						
Light sweet crude oil	**61.0**	100.8	89.6	99.4	108.8	99.6
Diesel	**12.9**	31.4	36.9	25.3	22.8	29.1
Light sour crude oil	**80.5**	142.4	146.8	150.5	102.7	135.7
Bitumen	**42.3**	13.0	14.3	10.5	9.1	11.8
Total sales	**196.7**	287.6	287.6	285.7	243.4	276.2
Average sales price [1],[b] (excluding Syncrude)						
Light sweet crude oil *	**80.84**	77.71	71.99	65.83	54.64	67.26
Other (diesel, light sour crude oil and bitumen) *	**69.53**	72.93	67.51	62.71	48.80	64.18
Total *	**73.03**	74.61	68.91	63.79	51.46	65.29
Total	**70.21**	65.42	62.01	59.34	59.45	61.66
Syncrude average sales price [1],[b]	**83.21**	78.81	75.17	—	—	77.36
Cash operating costs and Total operating costs – Total operations (excluding Syncrude) [c]						
Cash costs	**46.50**	35.10	30.65	29.65	30.65	31.50
Natural gas	**5.40**	3.40	1.55	1.65	3.00	2.40
Imported bitumen	**2.95**	0.20	0.05	—	0.05	0.05
Cash operating costs [2]	**54.85**	38.70	32.25	31.30	33.70	33.95
Project start-up costs	**0.55**	0.50	0.45	0.35	0.65	0.45
Total cash operating costs [3]	**55.40**	39.20	32.70	31.65	34.35	34.40
Depreciation, depletion and amortization	**12.65**	10.00	7.60	7.20	7.30	8.00
Total operating costs [4]	**68.05**	49.20	40.30	38.85	41.65	42.40
Cash operating costs and Total operating costs – Syncrude [c] ****						
Cash costs	**39.60**	29.65	29.50	—	—	29.60
Natural gas	**4.50**	3.45	2.10	—	—	2.90
Cash operating costs [2]	**44.10**	33.10	31.60	—	—	32.50
Project start-up costs	**—**	—	—	—	—	—
Total cash operating costs [3]	**44.10**	33.10	31.60	—	—	32.50
Depreciation, depletion and amortization	**13.70**	11.80	12.70	—	—	12.15
Total operating costs [4]	**57.80**	44.90	44.30	—	—	44.65
Cash operating costs and Total operating costs – In-situ bitumen production only [c] *****						
Cash costs	**12.30**	14.25	13.25	16.40	15.25	14.55
Natural gas	**7.05**	6.05	4.30	5.30	7.90	5.70
Cash operating costs [5]	**19.35**	20.30	17.55	21.70	23.15	20.25
Project start-up costs	**0.95**	1.35	0.65	1.45	2.30	1.35
Total cash operating costs [6]	**20.30**	21.65	18.20	23.15	25.45	21.60
Depreciation, depletion and amortization	**5.05**	6.65	5.95	6.00	6.95	6.35
Total operating costs [7]	**25.35**	28.30	24.15	29.15	32.40	27.95
Ending capital employed excluding major projects in progress [i]	**17 829**	16 141	14 833	10 008	10 610	
(for the twelve months ended)						
Return on capital employed [j]	**5.2**	4.2	8.4	11.1	22.9	
Return on capital employed [j]**	**3.1**	2.5	4.9	6.5	13.9	

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Twelve months ended
	Mar 31 2010	Dec 31 2009	Sept 30 2009	June 30 2009	Mar 31 2009	Dec 31 2009
NATURAL GAS						
Gross production						
Natural gas [d]						
Continuing operations	**560**	559	413	155	167	325
Discontinued operations	**89**	115	104	37	33	73
Natural gas liquids and crude oil [a]						
Continuing operations	**9.0**	8.5	6.1	1.4	1.6	4.5
Discontinued operations	**5.0**	6.5	4.5	1.8	1.5	3.6
Total gross production [f]						
Continuing operations	**614**	610	450	163	177	352
Discontinued operations	**119**	154	131	48	42	94
Average sales price from continuing operations [1]						
Natural gas [g]	**5.29**	4.59	2.87	3.48	5.51	4.19
Natural gas [g] *	**5.29**	4.58	2.85	3.44	5.50	4.17
Natural gas liquids and crude oil [b]	**70.02**	64.01	58.47	38.17	45.91	58.41
Ending capital employed [i]	**2 489**	3 349	3 632	1 200	1 195	
(for the twelve months ended)						
Return on capital employed [j]	**1.2**	(8.4)	(9.6)	(1.7)	5.0	

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Twelve months ended
	Mar 31 2010	Dec 31 2009	Sept 30 2009***	June 30 2009	Mar 31 2009	Dec 31 2009***
INTERNATIONAL AND OFFSHORE						
East Coast Canada						
Production [(a)]						
Terra Nova	**29.6**	24.0	16.0	—	—	20.8
Hibernia	**30.2**	26.3	28.5	—	—	27.2
White Rose	**14.8**	13.3	5.1	—	—	10.0
Total production	**74.6**	63.6	49.6	—	—	58.0
Average sales price [(1)] [(b)]	**78.69**	77.71	75.22	—	—	76.86
International						
Production [(e)]						
North Sea						
Buzzard	**58.6**	59.9	29.4	—	—	47.8
Production from discontinued operations	**27.5**	31.1	25.2	—	—	28.7
Total North Sea	**86.1**	91.0	54.6	—	—	76.5
Other International						
Libya	**35.4**	26.0	42.7	—	—	32.6
Production from discontinued operations	**11.7**	12.0	11.3	—	—	11.7
Total Other International	**47.1**	38.0	54.0	—	—	44.3
Total production	**133.2**	129.0	108.6	—	—	120.8
Average sales price from continuing operations [(1)] **– North Sea** [(l)]	**72.36**	68.71	72.02	—	—	69.53
Average sales price from continuing operations [(1)] **– Other International** [(l)]	**73.40**	79.18	75.60	—	—	78.05
Ending capital employed excluding major projects in progress [(i)]	**4 570**	4 970	4 903	—	—	
(for the twelve months ended)						
Return on capital employed [(j)]	**16.5**	11.2	9.3	—	—	
Return on capital employed [(j)]**	**10.4**	7.1	5.9	—	—	

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Twelve months ended
	Mar 31 2010	Dec 31 2009	Sept 30 2009	June 30 2009	Mar 31 2009	Dec 31 2009
REFINING AND MARKETING						
Eastern North America						
Refined product sales (h)						
Transportation fuels						
Gasoline	**23.5**	23.0	18.3	8.7	8.2	14.6
Distillate	**14.0**	13.9	10.3	5.4	5.1	8.8
Total transportation fuel sales	**37.5**	36.9	28.6	14.1	13.3	23.4
Petrochemicals	**2.2**	1.2	1.7	1.0	1.0	0.8
Asphalt	**1.8**	2.0	2.4	0.7	0.8	1.5
Other	**5.3**	1.9	3.0	1.0	0.5	2.0
Total refined product sales	**46.8**	42.0	35.7	16.8	15.6	27.7
Crude oil supply and refining						
Processed at refineries (h)	**31.0**	28.3	25.5	11.8	11.3	29.6
Utilization of refining capacity (j)	**91**	83	94	87	84	87
Western North America						
Refined product sales (h)						
Transportation fuels						
Gasoline	**14.8**	18.4	16.1	8.9	8.2	13.0
Distillate	**14.4**	15.6	11.8	5.0	5.4	9.5
Total transportation fuel sales	**29.2**	34.0	27.9	13.9	13.6	22.5
Asphalt	**1.2**	0.9	1.7	1.4	1.2	1.3
Other	**5.0**	6.0	4.6	1.8	1.0	3.4
Total refined product sales	**35.4**	40.9	34.2	17.1	15.8	27.2
Crude oil supply and refining						
Processed at refineries (h)	**33.5**	33.4	27.8	15.6	14.2	33.6
Utilization of refining capacity (j)	**92**	96	100	106	96	97
Ending capital employed excluding major projects in progress (i)	**7 794**	7 727	7 730	2 573	2 566	
(for the twelve months ended)						
Return on capital employed (j)	**6.6**	8.7	2.6	0.7	0.6	

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Twelve months ended
	Mar 31 2010	Dec 31 2009	Sept 30 2009	June 30 2009	Mar 31 2009	Dec 31 2009
NETBACKS – CONTINUING OPERATIONS						
Natural Gas [g]						
Average price realized [8]	**6.24**	5.14	3.90	3.58	5.64	5.23
Royalties	**(0.98)**	(0.70)	(0.16)	0.88	(1.00)	(0.47)
Operating costs	**(1.63)**	(1.81)	(1.91)	(1.78)	(1.82)	(2.10)
Operating netback	**3.63**	2.63	1.83	2.68	2.82	2.66
Depreciation, depletion and amortization	**(3.11)**	(2.59)	(2.89)	(3.36)	(3.17)	(3.25)
Administrative expenses and other	**(0.37)**	(1.28)	(1.93)	(2.12)	(0.97)	(1.56)
Earnings before income taxes	**0.15**	(1.24)	(2.99)	(2.80)	(1.32)	(2.15)
International and Offshore						
East Coast Canada [b]						
Average price realized [8]	**80.79**	79.69	77.85	—	—	79.07
Royalties	**(28.78)**	(25.26)	(21.02)	—	—	(23.82)
Operating costs	**(8.92)**	(7.89)	(13.36)	—	—	(9.76)
Operating netback	**43.09**	46.54	43.47	—	—	45.49
Depreciation, depletion and amortization	**(23.38)**	(26.56)	(17.48)	—	—	(23.47)
Administrative expenses and other	**0.31**	(1.33)	(0.52)	—	—	(1.05)
Earnings before income taxes	**20.02**	18.65	25.47	—	—	20.97
International – North Sea [b]						
Average price realized [8]	**74.19**	70.38	75.49	—	—	71.64
Operating costs	**(4.92)**	(4.57)	(6.29)	—	—	(4.99)
Operating netback	**69.27**	65.81	69.20	—	—	66.65
Depreciation, depletion and amortization	**(22.76)**	(25.24)	(18.54)	—	—	(23.60)
Administrative expenses and other	**(3.35)**	(2.20)	(2.83)	—	—	(2.36)
Earnings before income taxes	**43.16**	38.37	47.83	—	—	40.69
International – Libya						
Average price realized [8]	**73.92**	79.97	76.02	—	—	78.19
Royalties	**(43.28)**	(32.12)	(46.46)	—	—	(39.88)
Operating costs	**(3.81)**	(6.03)	(2.21)	—	—	(4.05)
Operating netback	**26.83**	41.82	27.35	—	—	34.26
Depreciation, depletion and amortization	**(4.29)**	(6.39)	(1.54)	—	—	(3.86)
Administrative expenses and other	**(6.63)**	(11.46)	(5.98)	—	—	(8.60)
Earnings before income taxes	**15.91**	23.97	19.83	—	—	21.80
International – Total [l]						
Average price realized [8]	**74.09**	73.28	75.80	—	—	74.30
Royalties	**(16.32)**	(9.71)	(27.50)	—	—	(16.19)
Operating costs	**(4.50)**	(5.01)	(3.88)	—	—	(4.61)
Operating netback	**53.27**	58.56	44.42	—	—	53.50
Depreciation, depletion and amortization	**(15.79)**	(19.54)	(8.48)	—	—	(15.59)
Administrative expenses and other	**(4.59)**	(5.01)	(4.69)	—	—	(4.89)
Earnings before income taxes	**32.89**	34.01	31.25	—	—	33.02

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) Average sales price	– This operating statistic is calculated before royalties (where applicable) and net of related transportation costs.
(2) Cash operating costs	– Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense 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.
(3) Total cash operating costs	– Include cash operating costs – Total operations as defined above and cash start-up costs. Per barrel amounts are based on total production volumes.
(4) Total operating costs	– Include total cash operating costs – Total operations as defined above and non-cash operating costs. Per barrel amounts are based on total production volumes.
(5) Cash operating costs – In-situ bitumen production	– Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes) and accretion expense. Per barrel amounts are based on in-situ production volumes only.
(6) 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.
(7) 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.
(8) Average price realized	– This operating statistic is calculated before transportation costs and royalties and excludes the impact of hedging activities.

Explanatory Notes

* Excludes the impact of realized hedging activities.

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

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

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

***** Calculation of cash operating costs and total operating costs for in-situ bitumen production has been revised in the first quarter of 2010, and comparative periods restated. Certain general and administrative costs that had not previously been allocated to in-situ have now been included.

(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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