FIRST QUARTER 2011
Report to shareholders for the period ended March 31, 2011

Suncor Energy first quarter results: Integrated strategy drives strong earnings in volatile markets

All financial figures are unaudited and in Canadian dollars (Cdn$) 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 non-GAAP measures, see the Non-GAAP Financial Measures Advisory section of Suncor's Management's Discussion and Analysis, dated May 2, 2011 (the MD&A).

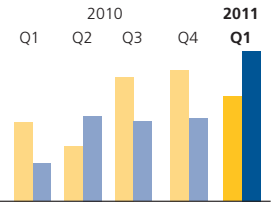
Suncor Energy Inc. (Suncor, or the company) recorded first quarter 2011 net earnings of $1.028 billion ($0.65 per common share), compared to net earnings of $779 million ($0.50 per common share) for the first quarter of 2010.

Operating earnings[1], which are adjusted for significant items that are not indicative of operating performance, increased to $1.478 billion ($0.94 per common share) in the first quarter of 2011 from $370 million ($0.24 per common share) in the first quarter of 2010. The increase in operating earnings compared to the first quarter of 2010 was primarily due to higher oil sands production volumes, higher margins for refined products in downstream refining operations and higher realized prices in upstream operations.

Cash flow from operations[1] more than doubled to $2.393 billion ($1.52 per common share) in the first quarter of 2011, compared to $1.124 billion ($0.72 per common share) in the first quarter of 2010. The increase in cash flow from operations was primarily due to the same factors that impacted operating earnings.

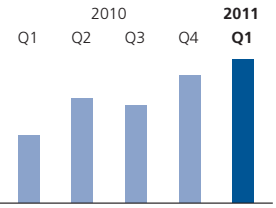
Suncor's total upstream production during the first quarter of 2011 averaged 601,300 barrels of oil equivalent per day (boe/d), compared to 564,600 boe/d during the first quarter of 2010. Crude oil production, as a percentage of total production, increased to 87% from 77% over the comparative period.

Earnings by Quarter
($ millions)



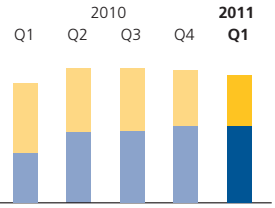
	2010 Q1	2010 Q2	2010 Q3	2010 Q4	**2011 Q1**
Net earnings	779	540	1 224	1 286	**1 028**
Operating earnings[1]	370	839	785	808	**1 478**

Cash Flow from Operations by Quarter[1]
($ millions)



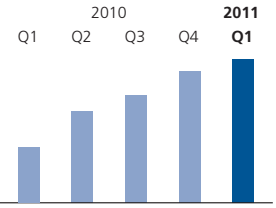
2010 Q1	2010 Q2	2010 Q3	2010 Q4	**2011 Q1**
1 124	1 770	1 629	2 129	**2 393**

Production by Quarter
(thousands of boe/d)



	2010 Q1	2010 Q2	2010 Q3	2010 Q4	**2011 Q1**
Exploration and Production	330.0	299.5	297.2	261.8	**240.7**
Oil Sands	234.6	334.4	338.3	363.8	**360.6**
Total	564.6	633.9	635.5	625.6	**601.3**

Return on Capital Employed by Quarter[1]
(%)
for the twelve months ended



2010 Q1	2010 Q2	2010 Q3	2010 Q4	**2011 Q1**
4.8	7.9	9.3	11.4	**12.5**

(1) Non-GAAP measures. See page 4 for a reconciliation of net earnings to operating earnings. Return on capital employed excludes capitalized costs related to major projects in progress. See the Non-GAAP Financial Measures Advisory section of the MD&A.

"Reliability and operational efficiency have been solid right across the business," said Rick George, president and chief executive officer. "Strong performance in our refining operations has allowed us to significantly benefit from higher margins and increasing demand as the economy recovers. In our oil sands operations, we've seen steady improvement over the past year, with the last two quarters showing our best production performance on record."

Oil Sands production (excluding Suncor's proportionate production share from the Syncrude joint venture) contributed an average of 322,100 barrels per day (bpd) in the first quarter of 2011, compared with first quarter 2010 production of 202,300 bpd. Production volumes were consistent with the record levels achieved in the fourth quarter of 2010, reflecting operational improvements. Production during the first quarter of 2010 was negatively impacted by operational upsets and unplanned maintenance at Oil Sands.

Cash operating costs[(1)] for oil sands operations (excluding Syncrude) decreased to $36.15 per barrel in the first quarter of 2011, compared to $54.50 per barrel during the first quarter of 2010. The decrease is primarily a reflection of largely fixed cash operating costs being spread over a greater production volume.

Suncor's proportionate share of production from the Syncrude joint venture contributed an average of 38,500 bpd of production during the first quarter of 2011 compared to 32,300 bpd in the same quarter of 2010.

The Exploration and Production segment contributed 240,700 boe/d of production in the first quarter of 2011 compared to 330,000 boe/d in the same period of 2010. The production decrease primarily reflected the divestiture of non-core assets over the past year, which contributed incremental production of 70,000 boe/d in the first quarter of 2010. The new Exploration and Production segment combines results previously reported as part of Suncor's Natural Gas and International and Offshore segments.

In the company's downstream Refining and Marketing segment, total refined product sales averaged 84,900 cubic metres per day during the first quarter of 2011 compared to 82,200 cubic metres per day in the first quarter of 2010. Significantly higher refining margins, reflected by widening benchmarks for industry cracking margins, and the heavy crude processing capacity of Suncor's refineries supported strong earnings from the segment.

"Results this quarter underline the strength of Suncor's integrated strategy as we were able to leverage widening light/heavy crude oil differentials in North America, while also benefiting from much higher prices for Brent crude in our offshore operations," said George.

Strategy and Operational Update

Suncor continues to move forward on its ten-year growth strategy outlined in December 2010. In support of the growth strategy, capital spending in the first quarter was primarily focused on expansion of the company's in situ oil sands operations, ongoing construction of a new oil sands hydrotreating unit and implementation of new tailings reclamation technology across existing oil sands mining operations.

In Suncor's in situ oil sands operations, construction is nearing completion on the Firebag Stage 3 expansion. In April 2011, Suncor began injecting steam into a Stage 3 well pad and expects to achieve first oil by early July 2011. The expansion is expected to be fully operational in the third quarter of 2011, with production volumes ramping up over approximately 24 months thereafter toward target capacity of 62,500 bpd of bitumen. The construction of infrastructure, well pads, and central plant and cogeneration facilities continues on Firebag Stage 4, with initial production targeted for the first quarter of 2013. Stage 4 also has a planned capacity of 62,500 bpd of bitumen.

With the closing of its strategic partnership agreements with Total E&P Canada Ltd. (Total) on March 22, 2011, Suncor expects to progress with engineering and site preparation work for the Fort Hills oil sands mining project and the Voyageur Upgrader. Under the terms of the agreements, Total assumed an interest in both Fort Hills and the Voyageur Upgrader, while Suncor assumed an interest in Total's Joslyn oil sands mining project. Suncor is targeting the completion of the Voyageur Upgrader and the Fort Hills project for 2016.

(1) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of the MD&A.

In Suncor's Exploration and Production segment, Suncor completed its sale of non-core North Sea assets in March for proceeds of £105 million (Cdn$164 million), subject to closing adjustments.

Exploration programs continue with Suncor securing two operated exploration licences and one non-operated exploration licence in the Norway portion of the North Sea in April 2011. In addition, the company is evaluating an exploratory well in the Ballicatters field offshore East Coast Canada.

Suncor expects to delay the 15-week dockside maintenance program at Terra Nova, originally planned for July 2011, to 2012. The delay is expected to allow for the resolution of the presence of hydrogen sulphide in certain wells, which has caused partial shut-ins of production, to be implemented concurrently. A four-week annual maintenance outage at Terra Nova during the third quarter of 2011 is still planned.

In conventional international operations, in response to the political situation in Libya, Suncor suspended exploration and production activities in the country indefinitely. Suncor continues to monitor the situation in Libya and to date has taken all reasonable steps to ensure the safety of its people and preserve the value of its assets and operations, and to maintain compliance with the company's Principles for Responsible Investment and Operations, which define Suncor's human rights values and policies in areas in which we operate. On March 18, 2011, Suncor declared force majeure under its Exploration and Production Sharing Agreements. As at March 31, 2011, Suncor had not recorded any impairment adjustments to its assets in Libya. However, should the current situation in Libya persist or worsen, such that Suncor is unable to resume operations in the near term or without significant remedial expenditure, Suncor believes its assets in Libya could be impaired in the future.

In Suncor's renewable energy business, expansion of the St. Clair ethanol plant, Canada's largest biofuels facility, was completed in January. Construction continued in the first quarter of 2011 on two new wind power projects, Kent Breeze in Ontario and Wintering Hills in Alberta. By the end of 2011, Suncor expects that its renewable energy projects will displace a total of nearly one million tonnes of carbon dioxide annually.

As Suncor invests in its growth strategy, managing debt and maintaining a strong balance sheet remain a priority. Driven by strong cash flow and proceeds from asset sales, including the strategic partnership with Total, net debt was reduced by $3.8 billion in the quarter to $7.4 billion at March 31, 2011.

Corporate Guidance

Suncor has updated its corporate guidance that it previously issued on December 17, 2010.

	2011 Full Year Outlook December 17, 2010	Actual Three Months Ended March 31, 2011	**2011 Full Year Outlook Revised May 3, 2011**
Suncor Total Production (boe/d)			
Production – before targeted divestitures[1]	550,000 – 600,000	601,300	**520,000 – 570,000**
Oil Sands (excluding Syncrude) (bpd)	280,000 – 310,000	322,100	**280,000 – 310,000**
Syncrude (bpd)	35,000 – 37,000	38,500	**35,000 – 37,000**
Exploration and Production			
East Coast Canada (bpd)	58,000 – 65,000	65,000	**58,000 – 65,000**
International (boe/d)	110,000 – 120,000	107,200	**80,000 – 90,000**
North American Onshore (mmcfe/d)[1][2]	370 – 410	411	**370 – 410**
Oil Sands Sales[3]			
Sweet	47%	37%	**41%**
Sour	53%	63%	**59%**
Oil Sands realization on crude sales basket (WTI @ Cushing less)[3]	Cdn$7.00 to Cdn$8.00 per barrel	Cdn$10.15 per barrel	**Cdn$5.50 to Cdn$6.50 per barrel**

(1) Actual production results will be impacted by the timing of planned divestitures of assets.

(2) Volumes are in millions of cubic feet equivalent of natural gas per day (mmcfe/d).

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

The key changes to the company's guidance presented above include:

- A decrease of 30,000 boe/d in International production and in Suncor total production. This decrease primarily reflects the shut-in of production in Libya.
- A decrease in the sweet/sour sales mix percentage from 47/53 to 41/59, which primarily reflects unscheduled outages during the first quarter of 2011 at Oil Sands hydrogen and hydrotreating units that negatively impacted production of higher value light sweet crude.
- An increase in the Oil Sands realization on its crude sales basket from WTI@Cushing less Cdn$7.00 – Cdn$8.00 per barrel to WTI@Cushing less Cdn$5.50 – Cdn$6.50 per barrel. This increase in sales realization primarily reflects stronger market prices for sweet and sour synthetic crude and stronger refining margins for diesel production, partially offset by widening light/heavy differentials and the impacts of the decrease in the guidance for Suncor's sweet/sour sales mix.

For further details regarding Suncor's 2011 corporate guidance, see www.suncor.com/guidance.

Operating Earnings[(1)(2)]

	Three months ended March 31	
($ millions)	**2011**	2010
Net earnings as reported	**1 028**	779
Unrealized foreign exchange gain on U.S. dollar denominated long-term debt	**(162)**	(230)
Loss/(gain) on significant disposals[(3)]	**170**	(204)
Impact of income tax rate adjustments on deferred income taxes[(4)]	**442**	—
Change in fair value of commodity derivatives used for risk management, net of realizations[(5)]	**—**	(8)
Redetermination of working interests in Terra Nova[(6)]	**—**	8
Modification of the bitumen valuation methodology[(7)]	**—**	9
Merger and integration costs	**—**	16
Operating earnings	**1 478**	370

(1) Operating earnings is a non-GAAP measure. All reconciling items are presented on an after-tax basis. See the Non-GAAP Financial Measures Advisory section of the MD&A.

(2) The company has restated prior year operating earnings for the transition to International Financial Reporting Standards and for the removal of certain prior year operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of the MD&A.

(3) Disposals in the first quarter of 2011 included the partial disposition of the company's interests in the Voyageur Upgrader and Fort Hills project and the completion of the sale of non-core assets in the United Kingdom (U.K.) portion of the North Sea. Disposals in the first quarter of 2010 included substantially all of the company's natural gas assets in the United States Rockies and certain natural gas assets in northeast British Columbia (known as Blueberry and Jedney).

(4) Adjustments to the company's deferred income taxes resulting from an increase in the U.K. tax rate on oil and gas profits from the North Sea.

(5) The company adjusts net earnings for the change in fair value of significant crude oil risk management derivatives. The company also holds less significant risk management derivatives for which the company does not adjust net earnings. The company held no significant crude oil risk management derivatives during the first quarter of 2011.

(6) Adjustment resulting from the settlement reached in the fourth quarter of 2010 related to the redetermination of working interests in the Terra Nova oil field. Operating earnings for 2010 have been restated to reflect the portion of the settlement attributable to the respective quarter.

(7) Adjustment reflects the impact of a royalty recovery in the fourth quarter of 2010 related to the Alberta government modifying the bitumen valuation methodology calculation for the interim period from January 1, 2009 to December 31, 2010. Operating earnings for 2010 have been restated to reflect the portion of the recovery attributable to the respective quarter.

Advisories

Certain financial measures in this document – namely operating earnings, cash flow from operations, return on capital employed and Oil Sands cash operating costs – are not prescribed by GAAP. These non-GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. These non-GAAP financial measures are included because management uses the information to analyze operating performance, leverage and liquidity. Therefore, these non-GAAP financial measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Certain crude oil and natural gas liquids (NGL) volumes have been converted to millions of cubic feet equivalent (mmcfe) of natural gas on the basis of one barrel (bbl) to six thousand cubic feet (mcf). Also, certain natural gas volumes have been converted to barrels of oil equivalent (boe) or thousands of boe (mboe) on the same basis. Any figure presented in mmcfe, boe or mboe may be misleading, particularly if used in isolation. A conversion ratio of one bbl of crude oil or NGL to six mcf of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the wellhead.

Unless otherwise noted, all financial information, including comparative figures pertaining to Suncor's 2010 results, has been prepared in accordance with Canadian GAAP, using accounting policies within the framework of International Financial Reporting Standards (IFRS) within Part 1 of the Canadian Institute of Chartered Accountants Handbook. In previous periods, the company prepared its Consolidated Financial Statements and Interim Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles in effect prior to January 1, 2011 (Previous GAAP). Comparative figures presented pertaining to Suncor's 2010 results have been restated to be in accordance with IFRS. A reconciliation of comparative figures from Previous GAAP to IFRS is provided in the notes to the unaudited Interim Consolidated Financial Statements for the period ended March 31, 2011.

The Strategy and Operational Update and Corporate Guidance above contain forward-looking information that is subject to a number of risks and uncertainties, many of which are beyond Suncor's control, including those outlined in Risk Factors below. See the Advisory – Forward-Looking Information section of the MD&A for the material risks and assumptions underlying this forward-looking information.

Risk Factors

Assumptions for the Oil Sands 2011 Full Year Outlook include reliability and operational efficiency initiatives that we expect will minimize unplanned maintenance in 2011. Assumptions for the East Coast Canada, International and North American Onshore 2011 Full Year Outlook include reservoir performance, drilling results, facility reliability, changes in production quotas and successful execution of planned maintenance events.

Factors that could potentially impact Suncor's operational outlook for 2011 include, but are not limited to:

- Bitumen supply. Ore grade quality, unplanned maintenance of mine equipment and extraction plants, tailings storage and in situ reservoir performance could impact 2011 production targets.
- Performance of recently commissioned facilities. Production rates while new equipment is being lined out are difficult to predict and can be negatively impacted by unplanned maintenance.
- Unplanned maintenance. Production estimates could be negatively impacted if unplanned work is required at any of our mining, production, upgrading, refining, pipeline, or offshore assets.
- Planned maintenance events. Production estimates could be negatively impacted if planned maintenance events 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 – such as those in Libya and Syria – are subject to a number of political, economic and socio-economic risks, including civil unrest and political violence.

MANAGEMENT'S DISCUSSION AND ANALYSIS

May 2, 2011

This Management's Discussion and Analysis (MD&A) should be read in conjunction with Suncor's March 31, 2011 unaudited Interim Consolidated Financial Statements and the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2010.

Additional information about Suncor filed with Canadian securities commissions and the United States (U.S.) Securities and Exchange Commission (SEC), including quarterly and annual reports and the Annual Information Form dated March 3, 2011 (the 2010 AIF), which is also filed with the SEC under cover of Form 40-F, is available online at www.sedar.com, www.sec.gov and our website www.suncor.com.

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

Basis of Presentation

Unless otherwise noted, all financial information, including comparative figures pertaining to Suncor's 2010 results, has been prepared in accordance with Canadian generally accepted accounting principles (GAAP), specifically International Accounting Standard (IAS) 34 – *Interim Financial Reporting*, within Part 1 of the Canadian Institute of Chartered Accountants Handbook.

This is Suncor's first MD&A presented with figures prepared using accounting policies within the framework of International Financial Reporting Standards (IFRS). In previous periods, the company prepared its Consolidated Financial Statements and Interim Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles in effect prior to January 1, 2011 (Previous GAAP). Comparative figures presented in this MD&A pertaining to Suncor's 2010 results have been restated to be in accordance with IFRS. A reconciliation of comparative figures from Previous GAAP to IFRS is provided in the notes to the March 31, 2011 unaudited Interim Consolidated Financial Statements. Comparative figures presented in this MD&A pertaining to Suncor's 2009 results were prepared in accordance with Previous GAAP and were not required by IFRS 1 – *First-Time Adoption of International Financial Reporting Standards* or by the Canadian Securities Administrators to be restated in accordance with IFRS.

All financial information is reported in Canadian dollars (Cdn$), unless otherwise noted. Certain amounts in prior years have been reclassified to conform to the current year's presentation.

Petro-Canada Merger

On August 1, 2009, Suncor completed its merger with Petro-Canada, referred to in this MD&A as the "merger". Amounts disclosed in this MD&A for 2009 reflect the results of post-merger Suncor from August 1, 2009 together with the results of pre-merger Suncor only from January 1, 2009 through July 31, 2009.

Non-GAAP Financial Measures

Certain financial measures in this MD&A – namely operating earnings, cash flow from operations, return on capital employed (ROCE) and Oil Sands cash operating costs – are not prescribed by GAAP. Operating earnings are defined in the Non-GAAP Financial Measures Advisory section of this MD&A and reconciled to GAAP net earnings in the Consolidated Financial Information and Segmented Results and Analysis sections of this MD&A. Oil Sands cash operating costs are defined and reconciled in the Segmented Results and Analysis – Oil Sands section of this MD&A. Cash flow from operations and ROCE are reconciled in the Non-GAAP Financial Measures Advisory section of this MD&A.

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 management uses the information to analyze operating performance, leverage and liquidity. Therefore, these non-GAAP financial measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Other Advisories

This 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. Refer to the Advisory – Forward-Looking Information section of this MD&A for information on the material risk factors and assumptions underlying our forward-looking information.

Certain crude oil and natural gas liquids volumes have been converted to millions of cubic feet equivalent (mmcfe) of natural gas on the basis of one barrel (bbl) to six thousand cubic feet (mcf). Also, certain natural gas volumes have been converted to barrels of oil equivalent (boe) or thousands of boe (mboe) on the same basis. Any figure presented in mmcfe, boe and mboe may be misleading, particularly if used in isolation. A conversion ratio of one bbl of crude oil or natural gas liquids to six mcf of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the wellhead.

SUNCOR OVERVIEW

Suncor Energy Inc. is an integrated energy company headquartered in Calgary, Alberta. Suncor has classified its operations into the following segments:

Oil Sands

Located in northeast Alberta, Suncor's Oil Sands segment recovers bitumen from mining and in situ operations and upgrades the majority of this production into refinery feedstock, diesel fuel and byproducts. The company's marketing plan includes sales of bitumen when market conditions are favourable or when operating conditions warrant. Oil Sands has interests in the Syncrude oil sands mining and upgrading joint venture and in significant growth projects, including the Fort Hills and Joslyn mining projects, and the Voyageur Upgrader.

Exploration and Production

Suncor's Exploration and Production segment comprises production and exploration operations offshore Canada and in the North Sea, and onshore in North America, Libya and Syria.

In January 2011, Suncor announced the creation of the Exploration and Production segment, combining its International and Offshore and Natural Gas segments. This realignment will allow Suncor to share best practices across its conventional oil and gas assets, with a view to optimizing returns and managing risk and growth.

For its North American Onshore operations (previously the Natural Gas segment), Suncor owns interests in a number of assets in Western Canada that primarily produce natural gas.

In East Coast Canada, Suncor operates Terra Nova, holding a working interest of 37.675%. Suncor also holds a 20% interest in Hibernia and a 19.5% interest in the Hibernia Southern Extension, a 27.5% interest in White Rose and a 26.125% interest in the White Rose Extensions, and a 22.7% interest in Hebron, all of which are operated by other companies.

In the North Sea, Suncor holds a 29.9% working interest in Buzzard, a 26.69% interest in the Golden Eagle Area Development – both of which are operated by another company – and interests in several licences offshore Norway and the United Kingdom (U.K.).

Suncor operates in Syria, pursuant to a production sharing contract (PSC), in the Ebla gas project to develop the Ash Shaer and Cherrife areas. Suncor operates in Libya, pursuant to Exploration and Production Sharing Agreements (EPSA, a form of PSC), on the joint development of oil fields in the Sirte Basin. Due to recent events in Libya, the company has suspended operations in the country indefinitely.

Refining and Marketing

Suncor's Refining and Marketing segment refines crude oil into a broad range of petroleum and petrochemical products at refineries located in Edmonton, Alberta, Montreal, Quebec and Sarnia, Ontario in Canada and Commerce City, Colorado in the U.S.

Refined products are sold to retail, commercial and industrial customers through a combination of company-owned, branded-dealer and other retail stations in Canada and Colorado, a nationwide Canadian commercial road transport network, and a bulk sales channel.

Refining and Marketing also owns a lubricants business located in Mississauga, Ontario that manufactures, blends and markets high quality products worldwide.

Other assets include interests in a petrochemical plant, pipelines and product terminals in Canada and the U.S.

The grouping **Corporate, Energy Trading and Eliminations** includes the company's investments in renewable energy projects, results related to energy supply and trading activities, and other activities not directly attributable to any other operating segment. The company's renewable energy interests include four operating wind power projects – with two additional projects under construction – and the St. Clair ethanol plant in Ontario. Energy trading activities primarily involve the marketing and trading of crude oil, natural gas, refined petroleum products and byproducts, and the use of financial derivatives to optimize related trading strategies.

FIRST QUARTER HIGHLIGHTS

- **Strong financial results.** First quarter results were indicative of a very strong business environment for crude oil and refined products, reflected by significant increases in benchmark prices, as well as increased production from Oil Sands.

  Consolidated net earnings for the first quarter of 2011 were $1.028 billion, compared with net earnings of $779 million for the first quarter of 2010. Operating earnings[(1)] for the first quarter of 2011 were $1.478 billion, compared to $370 million in the first quarter of 2010. ROCE[(1)] (excluding major projects in progress) was 12.5% in the first quarter of 2011, compared to 4.8% in the first quarter of 2010.

- **Cash flow doubled – net debt trimmed.** Cash flow from operations[(1)] was $2.393 billion in the first quarter of 2011, compared to $1.124 billion in the first quarter of 2010. Net debt was $7.4 billion at March 31, 2011 and decreased by $3.8 billion during the quarter, largely due to increased cash flow from operations and receipt of proceeds on asset dispositions.

- **Continued focus on operational integrity is critical.** In the first quarter of 2011, Oil Sands continued the strong performance it demonstrated in the second half of 2010, averaging production volumes of 322,100 barrels per day (bbls/d), excluding Syncrude. Refinery utilizations remained high – averaging 97% in the quarter – which, combined with above average industry cracking margins, allowed the Refining and Marketing segment to more than quadruple net earnings and nearly triple cash flow from operations.

  However, Suncor experienced problems with hydrogen and hydrotreating units at its Oil Sands facilities during the

quarter, resulting in decreased production of higher value light crude that negatively impacted Suncor's overall average sales price during the quarter.

- **Benefits of integration in a volatile business environment.** The impressive results in the Refining and Marketing segment, where Suncor's refineries are capable of processing oil sands feedstock, highlight the strategic advantage of the company's integrated assets. Suncor was able to capture the margins created by the strong demand for refined products, offsetting the negative impacts to the Oil Sands segment of lower prices for heavy crude feedstock caused by widening light/heavy differentials.
- **First steam into Firebag Stage 3.** In April 2011, the company started injecting steam into a well pad in the Firebag Stage 3 expansion. The company expects first oil production to be achieved in early July 2011, ramping up toward full production rates over approximately 24 months thereafter. The company had previously disclosed that first oil would be achieved by the end of the second quarter.
- **Strategic alliance with Total E&P Canada Ltd.** After receiving the necessary regulatory approvals on March 22, 2011, Suncor and Total E&P Canada Ltd. (Total) executed their previously announced joint venture agreements. In exchange for net proceeds of $1.820 billion (after closing adjustments) and a 36.75% interest in the Joslyn project, Suncor sold to Total a 49% interest in the Voyageur Upgrader and a 19.2% interest in the Fort Hills project. Suncor anticipates that these assets will be brought on-stream within five to seven years and plans to take advantage of opportunities to share resources and knowledge across the development of these projects. The development of the Voyageur Upgrader and the Fort Hills and Joslyn projects is subject to certain regulatory approvals and the approval by all joint venture partners and Suncor's Board of Directors.
- **Civil unrest in Libya.** Civil unrest in Libya in the middle of February escalated into political violence. Suncor responded initially by shutting down exploration activities and evacuating all Suncor expatriate personnel. Production was shut-in by early March.
- **Tax rate increase in the U.K.** In March 2011, the U.K. government increased the supplementary charge on oil and gas profits in the North Sea from 20% to 32%, which raised the overall statutory tax rate from 50% to 62%. The company adjusted its deferred income tax balances to reflect the tax rate increase, leading to a one-time negative adjustment to net earnings of $442 million in the first quarter of 2011.
- **Non-core U.K. assets divested.** On March 31, 2011, Suncor completed the sale of its non-core offshore U.K. assets for net proceeds of £105 million ($164 million), subject to closing adjustments.
- **Ethanol plant expansion completed.** In January 2011, Suncor completed the expansion of its ethanol plant in Ontario that doubled production capacity to 400 million litres per year and confirmed the plant as Canada's largest biofuels production facility.

(1) Operating earnings, cash flow from operations and ROCE are non-GAAP financial measures. The company has restated prior year operating earnings for the transition to IFRS and for the removal of certain prior year operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

CONSOLIDATED FINANCIAL INFORMATION

Net Earnings

Suncor's net earnings for the first quarter of 2011 were $1.028 billion, compared to $779 million in the first quarter of 2010, and were primarily affected by the changes in operating earnings described subsequently.

In the first quarter of 2011, the U.K. government announced an increase in the tax rate on oil and gas profits in the North Sea that increased the statutory tax rate on Suncor's earnings in the U.K. from 50% to 59.3% in 2011 and 62% in future years. The company revalued its deferred income tax balances, resulting in a one-time increase to deferred income tax expense of $442 million.

In the first quarter of 2011, the company sold partial interests in the Fort Hills and Voyageur Upgrader projects, resulting in an after-tax loss of $89 million (which included a $267 million reduction to goodwill), and completed the sale of non-core U.K. assets, resulting in an after-tax loss of $81 million. In the first quarter of 2010, the company sold non-core natural gas assets in the U.S. Rockies and northeast British Columbia (B.C.) and realized after-tax gains on disposal of $204 million.

The after-tax unrealized foreign exchange gain on the revaluation of U.S. dollar denominated long-term debt was $162 million in the first quarter of 2011, compared to $230 million in the first quarter of 2010.

Net Earnings by Segment

	Three months ended March 31	
($ millions)	**2011**	2010
Oil Sands	**605**	89
Exploration and Production	**(186)**	528
Refining and Marketing	**627**	147
Corporate, Energy Trading and Eliminations	**(18)**	15
Total	**1 028**	779

Operating Earnings

Consolidated Operating Earnings Reconciliation[(1)(2)]

	Three months ended March 31	
($ millions)	**2011**	2010
Net earnings as reported	**1 028**	779
Unrealized foreign exchange gain on U.S. dollar denominated long-term debt	**(162)**	(230)
Loss/(gain) on significant disposals[(3)]	**170**	(204)
Impact of income tax rate adjustments on deferred income taxes[(4)]	**442**	—
Change in fair value of commodity derivatives used for risk management, net of realizations[(5)]	**—**	(8)
Redetermination of working interests in Terra Nova[(6)]	**—**	8
Modification of the bitumen valuation methodology[(7)]	**—**	9
Merger and integration costs	**—**	16
Operating earnings	**1 478**	370

(1) Operating earnings is a non-GAAP measure that adjusts net earnings for significant items that are not indicative of operating performance that management believes reduces the comparability of the underlying financial performance between periods. All reconciling items are presented on an after-tax basis. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(2) The company has restated prior year operating earnings for the transition to IFRS and for the removal of certain prior year operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(3) Disposals in the first quarter of 2011 included the partial disposition of the company's interests in the Voyageur Upgrader and Fort Hills project and the completion of the sale of non-core assets in the U.K. portion of the North Sea. Disposals in the first quarter of 2010 included substantially all of the company's natural gas assets in the U.S. Rockies and certain natural gas assets in northeast B.C. (known as Blueberry and Jedney).

(4) Adjustments to the company's deferred income taxes resulting from an increase in the U.K. tax rate on oil and gas profits from the North Sea.

(5) The company adjusts net earnings for the change in fair value of significant crude oil risk management derivatives. The company also holds less significant risk management derivatives for which the company does not adjust net earnings. The company held no significant crude oil risk management derivatives during the first quarter of 2011.

(6) Adjustment resulting from the settlement reached in the fourth quarter of 2010 related to the redetermination of working interests in the Terra Nova oil field. Operating earnings for 2010 have been restated to reflect the portion of the settlement attributable to the respective quarter.

(7) Adjustments reflect the impact of a royalty recovery in the fourth quarter of 2010 related to the Alberta government modifying the bitumen valuation methodology calculation for the interim period from January 1, 2009 to December 31, 2010. Operating earnings for 2010 have been restated to reflect the portion of the recovery attributable to the respective quarter.

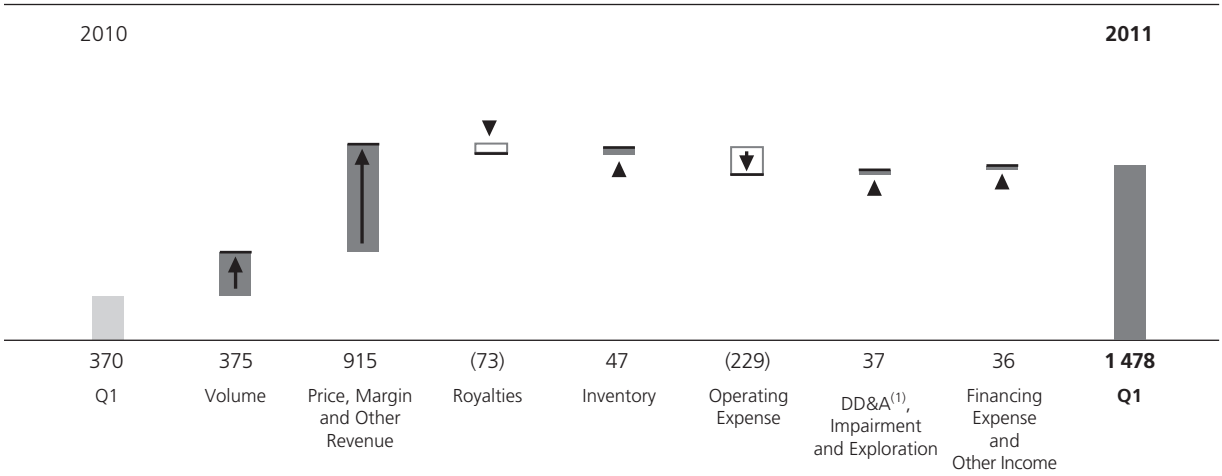
Operating Earnings by Segment[1]

	Three months ended March 31	
($ millions)	**2011**	2010
Oil Sands	**694**	90
Exploration and Production	**337**	332
Refining and Marketing	**627**	147
Corporate, Energy Trading and Eliminations	**(180)**	(199)
Total	**1 478**	370

(1) Non-GAAP measure. The company has restated prior year operating earnings for the transition to IFRS and for the removal of certain prior year operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Bridge Analysis of Consolidated Operating Earnings

($ millions)



(1) Depreciation, depletion and amortization.

Upstream Production Volumes

mboe per day (mboe/d)	Three months ended March 31 2011	2010
Oil Sands	**360.6**	234.6
Exploration and Production	**240.7**	330.0
Total	**601.3**	564.6

Downstream Sales Volumes

Thousands of cubic metres per day (thousands of m^3/d)	Three months ended March 31 2011	2010
Eastern North America	**44.6**	41.6
Western North America	**40.3**	40.6
Total refined product sales	**84.9**	82.2

Suncor's operating earnings for the first quarter of 2011 were $1.478 billion, compared to $370 million in the first quarter of 2010. Positive factors impacting operating earnings in the first quarter of 2011, compared to the same period in 2010, included:

- Realized prices for crude oil were considerably higher in the first quarter of 2011, reflected by significant increases in the benchmark prices for West Texas Intermediate (WTI) and Brent.
- Refining margins were also higher in the first quarter of 2011, reflected by large increases in benchmarks for 3-2-1 crack spreads. Earnings also benefited from the effects of a rising price environment, as inventories produced during periods of lower feedstock costs have been sold in the current period at increased prices that reflect current market conditions.
- Upstream production for the first quarter of 2011 averaged 601,300 boe per day (boe/d), up from 564,600 boe/d in the same period in 2010. The increase in production volumes occurred in Oil Sands and was due primarily to operational improvements in primary extraction and the negative impact of upgrader fires on prior year production. This increase was partially offset by decreases in Exploration and Production related to asset dispositions that Suncor completed throughout 2010.

These positive factors were partially offset by the following:

- Royalties were higher in the first quarter of 2011, mainly due to higher production volumes from Oil Sands and higher overall sales prices, partially offset by lower production volumes from Exploration and Production.
- Operating expenses were higher in the first quarter of 2011, mainly due to higher share-based compensation expense that was triggered primarily by the increase in the company's common stock price.

Cash Flow from Operations and Net Debt

Cash flow from operations in the first quarter of 2011 was $2.393 billion, compared to $1.124 billion in the first quarter of 2010, due mainly to higher sales prices and higher Oil Sands production. As a result of higher cash flow from operations and the receipt of proceeds from the transfer of interests in the Voyageur Upgrader and Fort Hills projects to Total, the company's net debt decreased to $7.4 billion in the first quarter of 2011.

Cash Flow from Operations by Segment[1]

($ millions)	Three months ended March 31 2011	2010
Oil Sands	**1 137**	265
Exploration and Production	**583**	848
Refining and Marketing	**929**	328
Corporate, Energy Trading and Eliminations	**(256)**	(317)
Total	**2 393**	1 124

(1) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Quarterly Financial Data[1]

Three months ended ($ millions, unless otherwise noted)	**Mar 31 2011**	Dec 31 2010	Sept 30 2010	June 30 2010	Mar 31 2010	Dec 31 2009	Sept 30 2009	June 30 2009
Total production (mboe/d)	**601.3**	625.6	635.5	633.9	564.6	638.2	531.8	336.1
Revenue and other income								
Operating revenues (net of royalties)	**9 256**	8 981	7 718	8 174	7 130	6 950	5 397	2 647
Energy supply and trading activity income and interest and other income[2]	**589**	958	1 119	843	279	686	3 046	2 121
	9 845	9 939	8 837	9 017	7 409	7 636	8 443	4 768
Net earnings (loss)	**1 028**	1 286	1 224	540	779	457	929	(51)
Net earnings (loss) per common share (dollars)								
Basic	**0.65**	0.82	0.78	0.35	0.50	0.29	0.69	(0.06)
Diluted	**0.65**	0.82	0.78	0.34	0.46	0.29	0.68	(0.06)
Operating earnings[3][4]	**1 478**	808	785	839	370	342	362	56
Operating earnings per common share[3][4] (dollars)	**0.94**	0.52	0.50	0.54	0.24	0.22	0.29	0.06
Cash flow from operations[4]	**2 393**	2 129	1 629	1 770	1 124	1 129	574	295
Cash flow from operations per common share[4] (dollars)	**1.52**	1.36	1.04	1.13	0.72	0.72	0.43	0.31
ROCE[4][5] (%)								
For the twelve months ended	**12.5**	11.4	9.3	7.9	4.8	2.6	3.7	7.3
Common share information								
(Share price at the end of trading)								
Toronto Stock Exchange (Cdn$)	**43.48**	38.28	33.50	31.33	33.03	37.21	37.40	35.37
New York Stock Exchange (US$)	**44.84**	38.29	32.55	29.44	32.54	35.31	34.56	30.34

(1) Quarterly data for periods ending in 2009 is presented in accordance with Previous GAAP. Inputs for metrics for twelve-month periods have been calculated using earnings information prepared in accordance with IFRS for the portion of the twelve-month period pertaining to 2010 and under Previous GAAP for the portion of the twelve-month period pertaining to 2009. 2010 data includes amounts classified as discontinued operations under Previous GAAP. See the Basis of Presentation section of this MD&A.

(2) As a result of the merger, on October 1, 2009, the company began presenting on a net basis certain amounts in its energy supply and trading activities for commodity contracts that exceeded the company's expected purchase, sale or usage requirements.

(3) The company has restated 2010 operating earnings for the transition to IFRS and for the removal of certain prior year operating earnings adjustments. Operating earnings for periods ending in 2009 have not been restated for these items. See the Basis of Presentation and the Non-GAAP Financial Measures Advisory sections of this MD&A.

(4) Non-GAAP measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

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

Trends in Suncor's quarterly earnings results and cash flow from operations are driven primarily by production volumes and changes in commodity prices, refining crack spreads and foreign exchange rates, which are discussed in the Business Environment section of this MD&A.

Over the last two years, Suncor's results were impacted by several important events:

- Results in the first quarter of 2010 were negatively impacted by two upgrader fires that decreased Oil Sands production.
- As part of its strategic business alignment subsequent to the merger with Petro-Canada, Suncor divested a number of non-core assets in its Exploration and Production segment throughout 2010. The resulting gains and losses on disposal had one-time impacts on net earnings in the quarters in which they occurred.
- Significant changes occurring through the latter half of 2009 primarily reflect the merger, which closed August 1, 2009.
- The second quarter of 2009 was negatively impacted by the downturn in the economy, including mark-to-market losses on risk management commodity derivatives and costs to defer certain growth projects.

Net earnings over the last two years were also affected by other one-time adjustments, including:

- The fourth quarter of 2010 included a pre-tax gain of $295 million for the redetermination of working interests in the Terra Nova oil field and a pre-tax royalty recovery of $140 million with respect to the modification of the bitumen valuation methodology calculation.
- The second quarter of 2010 included pre-tax impairment adjustments totalling $233 million for Oil Sands assets that were being used in the development of an alternative extraction process and natural gas properties that the company decided not to pursue.
- The fourth quarter of 2009 included a one-time positive income tax rate adjustment of $148 million resulting from the provincial rate reduction in Ontario.
- The third quarter of 2009 included a pre-tax gain of $438 million for the effective settlement of a pre-existing processing agreement with Petro-Canada as a result of the merger.

Business Environment

Commodity prices, refining crack spreads and foreign exchange rates are some of the most significant factors that affect the results of Suncor's operations.

Three months ended (average for the period ended)		**Mar 31 2011**	Dec 31 2010	Sept 30 2010	June 30 2010	Mar 31 2010	Dec 31 2009	Sept 30 2009	June 30 2009
WTI crude oil at Cushing	US$/bbl	**94.10**	85.20	76.20	78.05	78.70	76.20	68.30	59.60
Dated Brent crude oil at Sullom Voe	US$/bbl	**104.95**	86.50	76.85	78.30	76.25	74.55	68.25	58.80
Dated Brent/Maya FOB price differential	US$/bbl	**15.65**	10.85	9.35	10.45	6.50	5.25	5.10	3.75
Canadian 0.3% par crude oil at Edmonton	Cdn$/bbl	**88.40**	80.70	74.80	76.30	80.45	77.00	70.60	65.30
Light/heavy crude oil differential of WTI at Cushing less Western Canadian Select (WCS) at Hardisty	US$/bbl	**23.15**	18.10	15.65	14.05	8.95	12.10	10.10	7.50
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**3.60**	3.60	3.50	3.85	5.35	4.25	3.00	3.65
New York Harbor 3-2-1 crack (1)	US$/bbl	**19.40**	12.20	9.60	12.50	7.95	5.55	9.90	10.20
Chicago 3-2-1 crack (1)	US$/bbl	**16.45**	9.20	10.15	11.05	5.65	4.15	7.65	10.15
Seattle 3-2-1 crack (1)	US$/bbl	**21.40**	13.50	16.60	15.50	8.55	5.95	12.80	13.35
Gulf Coast 3-2-1 crack (1)	US$/bbl	**18.50**	7.80	7.45	9.65	6.75	4.50	6.75	8.40
Exchange rate	US$/Cdn$	**1.01**	0.99	0.96	0.97	0.96	0.94	0.91	0.85

(1) 3-2-1 crack spreads are calculated by taking two times the spot price of gasoline at the stated location plus one, multiplied by the spot price of diesel at the same location, then subtracting three times the near-month contract price for NYMEX Light Sweet Crude Oil delivered at Cushing, and then dividing the entire sum by three.

Suncor's sweet synthetic crude oil price realizations are influenced primarily by changes in the price for WTI at Cushing. The average WTI price for the first quarter of 2011 increased to US$94.10/bbl from US$85.20/bbl in the fourth quarter of 2010 and from US$78.70/bbl in the first quarter of 2010.

Suncor produces a specific grade of sour synthetic crude oil in Alberta, the price realizations for which are influenced by changes in the price for WTI and for Canadian par crude at Edmonton, but which can also be affected by other conditions resulting from spot sales required to manage inventory levels.

Suncor's heavy crude oil price realizations are influenced by customers' alternatives. WCS at Hardisty is a common reference price for Canadian heavy crude oil. In the first quarter of 2011, the average light/heavy crude differential between WTI and WCS widened considerably to US$23.15/bbl, up from US$18.10/bbl in the fourth quarter of 2010 and from US$8.95/bbl in the first quarter of 2010.

Suncor's price realizations for crude oil production from East Coast Canada, the North Sea, Libya and Syria are influenced primarily by the price for Brent crude. Brent crude prices increased significantly in the first quarter of 2011, averaging US$104.95/bbl, and also traded at a substantial premium to WTI. This premium averaged US$10.85/bbl in the first quarter of 2011, compared to US$1.30/bbl in the fourth quarter of 2010 and a discount of US$2.45/bbl in the first quarter of 2010.

Suncor's price realizations for North American Onshore production are primarily referenced to Alberta spot at AECO. The AECO benchmark averaged $3.60/mcf for the first quarter of 2011, which was consistent with the fourth quarter of 2010 and lower than the average benchmark of $5.35/mcf in the first quarter of 2010.

Suncor's refining margins are influenced primarily by 3-2-1 crack spreads, which are industry indicators approximating the gross refining margin on a barrel of oil for gasoline and distillate, and by light/heavy crude differentials, which indicate when more complex refineries can earn greater margins by processing less expensive, heavier crudes. These benchmarks do not necessarily reflect the margins of a specific refinery, where actual crude purchase costs, refinery configuration and refined product sales markets reflect factors unique to that refinery. Crack spreads increased significantly in the first quarter of 2011, as prices for refined products outpaced those for crude feedstock, due in part to the WTI discount that developed in the quarter. Light/heavy crude differentials, including the Brent/Maya differential, also widened significantly in the first quarter of 2011.

The majority of Suncor's revenues from the sale of oil and natural gas commodities are based on prices that are determined by, or referenced to, U.S. dollar benchmark prices. The majority of Suncor's expenditures are realized in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease revenue received from the sale of commodities and, correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of commodities.

SEGMENTED RESULTS AND ANALYSIS

Oil Sands

Financial Highlights

($ millions, unless otherwise noted)	Three months ended March 31 2011	2010
Operating revenues (including royalties)	**3 199**	1 795
Less: Royalties	**(123)**	(70)
Operating revenues (net of royalties)	**3 076**	1 725
Net earnings	**605**	89
Operating earnings[1]	**694**	90
Cash flow from operations[1]	**1 137**	265
Total production (in thousands of bbls/d (mbbls/d))	**360.6**	234.6

(1) Non-GAAP measures. Operating earnings is reconciled to net earnings below. The company has restated prior year operating earnings for the transition to IFRS and for the removal of certain prior year operating earnings adjustments. See also the Non-GAAP Financial Measures Advisory section of this MD&A.

Oil Sands net earnings for the first quarter of 2011 were $605 million, compared to $89 million for the first quarter of 2010. Net earnings in the first quarter of 2011 included an after-tax loss of $89 million on the sale of partial interests in the Voyageur Upgrader and the Fort Hills project to Total.

Operating earnings for the first quarter of 2011 were $694 million, which was significantly higher than operating earnings of $90 million for the first quarter of 2010. Production volumes (excluding Syncrude) were consistent with the record levels achieved in the fourth quarter of 2010 – reflecting operational improvements in extraction activities – and were significantly higher than production volumes in the first quarter of 2010 – reflecting the impact of prior years' upgrader fires. However, earnings in the quarter were negatively impacted by operational issues with hydrogen and hydrotreating units at our upgrading facilities that decreased the amount of higher value light sweet crude production, weaker sales prices for heavy crude oil and higher operating expenses, including planned upgrader maintenance that is part of the company's rolling maintenance program.

Cash flow from operations for the first quarter of 2011 was $1.137 billion, compared to $265 million in the first quarter of 2010. The increase in cash flow from operations was due mainly to the same factors that affected operating earnings.

Operating Earnings

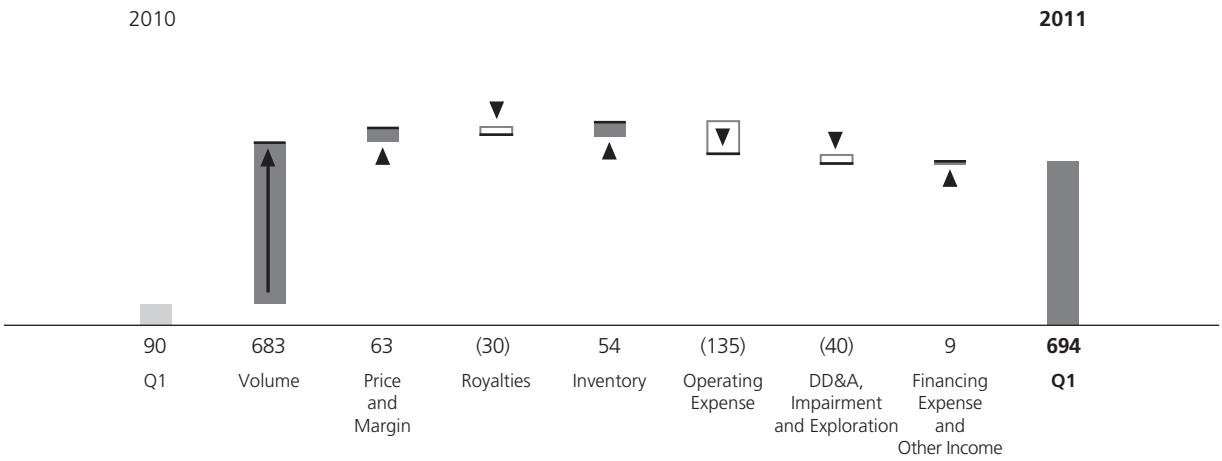
Operating Earnings Reconciliation

($ millions)	Three months ended March 31 2011	2010
Net earnings	**605**	89
Loss on significant disposals	**89**	—
Change in fair value of commodity derivatives used for risk management, net of realizations	**—**	(8)
Modification of the bitumen valuation methodology	**—**	9
Operating earnings[1]	**694**	90

(1) Non-GAAP measure. The company has restated prior year operating earnings for the transition to IFRS and for the removal of certain prior year operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Bridge Analysis of Operating Earnings

($ millions)



Production Volumes

(mbbls/d)	Three months ended March 31 2011	2010
Production excluding Syncrude	**322.1**	202.3
Syncrude production	**38.5**	32.3
Total production	**360.6**	234.6

Production volumes excluding Syncrude increased significantly in the first quarter of 2011, compared with the first quarter of 2010, and were within four mbbls/d of the record set in the fourth quarter of 2010, despite upgrader maintenance that was part of the company's rolling maintenance program. In 2010, production was negatively impacted by a fire and subsequent maintenance at Upgrader 2 in December 2009 and a second, unrelated fire at Upgrader 1 in February 2010. Upgrader 2 returned to normal production in early February 2010, while Upgrader 1 was restored to normal operations on April 1, 2010.

In situ production volumes averaged 87.3 mbbls/d of bitumen in the first quarter of 2011, compared to 87.5 mbbls/d of bitumen in the first quarter of 2010. Production volumes in the first quarter of 2011 at both Firebag and MacKay River operations were comparable to the same period in 2010.

First quarter Syncrude production increased to 38.5 mbbls/d in the first quarter of 2011, compared to 32.3 mbbls/d in the first quarter of 2010. Production was lower in the first quarter of 2010 primarily due to planned maintenance events.

Prices and Sales Volumes

	Three months ended March 31	
	2011	2010
Average sales price excluding Syncrude[1][2] ($/bbl)	**82.59**	70.21
Sales volumes excluding Syncrude (mbbls/d)	**326.2**	196.7
Sales mix (sweet/sour) (%)	**37/63**	38/62
Average sales price – Syncrude[1] ($/bbl)	**93.33**	83.21
Sales volumes – Syncrude (mbbls/d)	**38.5**	32.3

(1) Average sales price is before royalties and net of related transportation costs.

(2) Average sales price excluding Syncrude includes the impact of realized derivative gains and losses pertaining to the company's risk management activities.

Sales volumes increased in the first quarter of 2011, compared with the first quarter of 2010, due mainly to the impacts of upgrader fires on 2010 production. Although consistent with the same period in 2010, the sweet/sour sales mix in the first quarter of 2011 was lower than expected because of the impacts of unplanned outages in the hydrogen and hydrotreating units. Despite these outages, the company is encouraged by its progress in its reliability improvement efforts and plans to continue with this operational focus, with a particular emphasis on upgrading assets.

In the first quarter of 2011, Oil Sands average sales price benefited from higher benchmark prices for crude oil and diesel production. These positive effects were partially offset by the stronger Canadian dollar relative to the U.S. dollar.

Oil Sands average sales price was negatively impacted by the change in the sweet/sour sales mix and by light/heavy crude differentials, which widened significantly in the first quarter of 2011. The average sales price for bitumen was lower in the first quarter of 2011 than in the same period in 2010, negatively impacted by supply disruptions that increased prices for the diluent that is required to transport bitumen in pipelines. Suncor's realization for production (excluding Syncrude) averaged WTI less US$10.31/bbl in the first quarter of 2011, compared to WTI less US$8.65/bbl in the first quarter of 2010.

Royalties

Royalties were higher in the first quarter of 2011 than in the same period in 2010, due mainly to the effects of upgrader fires on 2010 production, higher WTI prices, and MacKay River reaching the post-payout phase in November 2010. These increases were mostly offset by higher capital expenditures for Suncor's Tailings Reduction Operations (TRO_{TM}) and other mining operations, and higher operating expenses.

Cash Operating Costs Reconciliation[1]

Total Oil Sands cash operating costs increased slightly to $1.050 billion in the first quarter of 2011, from $993 million in the first quarter of 2010, primarily due to higher maintenance costs for mining activities and unplanned outages at the hydrogen plants and the diesel hydrotreater. In situ cash operating costs were also higher due to increased maintenance activities and labour associated with new infrastructure, partially offset by lower natural gas costs due to lower benchmark prices. Oil Sands cash operating costs per barrel decreased mainly because of the increase in production volumes.

	Three months ended **March 31 2011**		Three months ended March 31 2010	
	$ millions	$/bbl	$ millions	$/bbl
Operating, selling and general expenses	**1 320**		1 162	
Less: Syncrude-related expenses[2]	**(133)**		(125)	
Less: Other non-production related costs[3]	**(137)**		(44)	
Cash operating costs – excluding Syncrude	**1 050**	**36.15**	993	54.50

(1) Cash operating costs and cash operating costs per barrel are non-GAAP measures, which are derived by adjusting operating, selling and general expenses – a GAAP measure – for expenses that management believes do not relate to the production performance of the operated oil sands assets. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(2) Cash operating costs exclude Suncor's proportionate share of production and operating, selling and general expenses from the Syncrude joint venture.

(3) Significant non-production related costs include earnings effects associated with items including, but not limited to, the change in inventory valuation, share-based compensation expense, costs related to the deferral of growth projects and the accretion of asset retirement obligations.

Expenses and Other Factors

Other operating expenses were higher in the first quarter of 2011 than in the same period in 2010, primarily due to higher share-based compensation expense that was triggered primarily by the increase in the company's stock price and higher project start-up costs related to increased activity for the Firebag Stage 3 and Stage 4 expansions, partially offset by lower costs related to the deferral of growth projects. The company continues to incur costs related to placing certain growth projects into "safe mode" as a result of the economic downturn in late 2008 and early 2009. These costs were $15 million (pre-tax) in the first quarter of 2011 and $37 million (pre-tax) in the first quarter of 2010. Safe mode costs include the costs for maintaining equipment and facilities related to projects still in safe mode and the costs of activities pertaining to the remobilization of equipment and personnel.

DD&A expense was higher in the first quarter of 2011 than in the same period in 2010, mainly because of a larger asset base. Exploration costs for in situ properties increased as the company undertook core hole drilling programs on several of its properties.

Planned Maintenance Events

The company has a planned maintenance event lasting approximately six weeks scheduled for the primary upgrading units in Upgrader 2 in the second quarter of 2011 – the largest such event in Suncor's history. To take advantage of current market conditions and maximize revenues, the company has changed the sequence of work on other units and advanced work originally planned later in the year. The overall time frame of this event is unchanged, and the company expects production volumes will be reduced by approximately 215,000 bbls/d over its duration.

The company also has planned maintenance events at central processing facilities for both Firebag, for two weeks in September and MacKay River, for two weeks overlapping the end of the third quarter.

Syncrude has a six-week planned maintenance event for September and October of 2011.

Impact of Strategic Alliance with Total

During the first quarter of 2011, Suncor and Total received all required approvals to complete their strategic alliance that was announced on December 17, 2010. The closing date for transactions that are part of the arrangement was March 22, 2011, with an effective date of January 1, 2011.

In consideration for Total acquiring a 49% interest in the Voyageur Upgrader, an additional 19.2% interest in the Fort Hills project, rights to certain knowledge and technology licences, and Total assuming its share of capital expenditures subsequent to the effective date, Suncor received $2.662 billion from Total (net of transaction costs) in the first quarter of 2011. Suncor recorded an after-tax loss of $89 million on the partial disposition of its assets, which included derecognizing $267 million of goodwill that the company allocated to its disposed interests.

Suncor retained a 51% interest in the Voyageur Upgrader and a 40.8% interest in the Fort Hills project. Total's interest in Fort Hills increased to 39.2%, with Teck Resources Limited holding the remaining 20% interest.

In consideration for Suncor acquiring a 36.75% interest in Joslyn and assuming its share of capital expenditures subsequent to the effective date, Suncor issued an $842 million note payable to Total that was paid on April 29, 2011, which was ten business days following receipt of the order-in-council of Alberta from the lieutenant-governor that approved development of the project.

Total retained a 38.25% interest in the Joslyn project, with Occidental Petroleum Corporation (15%) and Inpex Canada Ltd. (10%) holding the remaining interests.

Suncor anticipates that all three projects will be developed concurrently, with the Voyageur Upgrader and Fort Hills coming on-stream in 2016 and Joslyn coming on-stream by 2017 to 2018. The company's strategic alliance with Total also includes crude oil marketing agreements that take effect when the various growth projects commence operations.

Mine Financial Security Program

By law, oil sands mine companies are responsible for reclaiming land that is disturbed by mining and the operation of related plants. Standards for reclamation are set by the Government of Alberta. During the first quarter of 2011, the Alberta government announced it had finalized changes to its Mine Financial Security Program. These changes are not expected to impact Suncor in the near term as existing credit instruments provided by Suncor to the government will not be returned and remain in place.

Land-use Framework

On April 5, 2011, the Government of Alberta issued its draft Lower Athabasca Regional Plan (LARP). This plan, developed as part of the Land-Use Framework under the Alberta Land Stewardship Act, identifies new conservation areas, as well as management frameworks for air, surface water and groundwater quality.

Although the company is still reviewing the draft LARP, our preliminary assessment is that the conservation areas currently proposed do not appear to overlap Suncor's leases. The management frameworks formalize a number of regulatory tools that are already used by the government to manage environmental aspects of oil sands development, and may require Suncor to have greater participation in the evaluation of environmental issues.

Exploration and Production

Comparative figures for Exploration and Production are presented by combining results previously reported separately in the International and Offshore and Natural Gas segments.

Financial Highlights

($ millions, unless otherwise noted)	Three months ended March 31 2011	2010
Operating revenues (including royalties)	**1 815**	1 831
Less: Royalties	**(432)**	(402)
Operating revenues (net of royalties)	**1 383**	1 429
Net (loss) earnings	**(186)**	528
Operating earnings[1]	**337**	332
Cash flow from operations[1]	**583**	848
Total production (mboe/d)	**240.7**	330.0

(1) Non-GAAP measures. Operating earnings is reconciled to net earnings below. The company has restated prior year operating earnings for the transition to IFRS and for the removal of certain prior year operating earnings adjustments. See also the Non-GAAP Financial Measures Advisory section of this MD&A.

Exploration and Production had a net loss of $186 million in the first quarter of 2011, compared with net earnings of $528 million in the first quarter of 2010. The net loss in the first quarter of 2011 included a one-time negative deferred income tax adjustment of $442 million pertaining to the increase in the U.K. supplementary charge on oil and gas profits in the North Sea and an $81 million after-tax loss on disposal of non-core U.K. offshore assets. Net earnings in the first quarter of 2010 included after-tax gains of $204 million on non-core asset dispositions.

Exploration and Production had operating earnings of $337 million in the first quarter of 2011, compared with operating earnings of $332 million in the first quarter of 2010. The increase in operating earnings was primarily due to the impact of higher overall average sales prices and lower DD&A, partially offset by the impact of lower overall production volumes as a result of non-core asset dispositions throughout 2010, and the higher effective tax rate on U.K. earnings.

Cash flow from operations was $583 million in the first quarter of 2011, compared to $848 million in the first quarter of 2010, and was negatively impacted by lower overall production volumes and by current income tax due on the net proceeds received from the disposition of non-core U.K. assets.

Operating Earnings

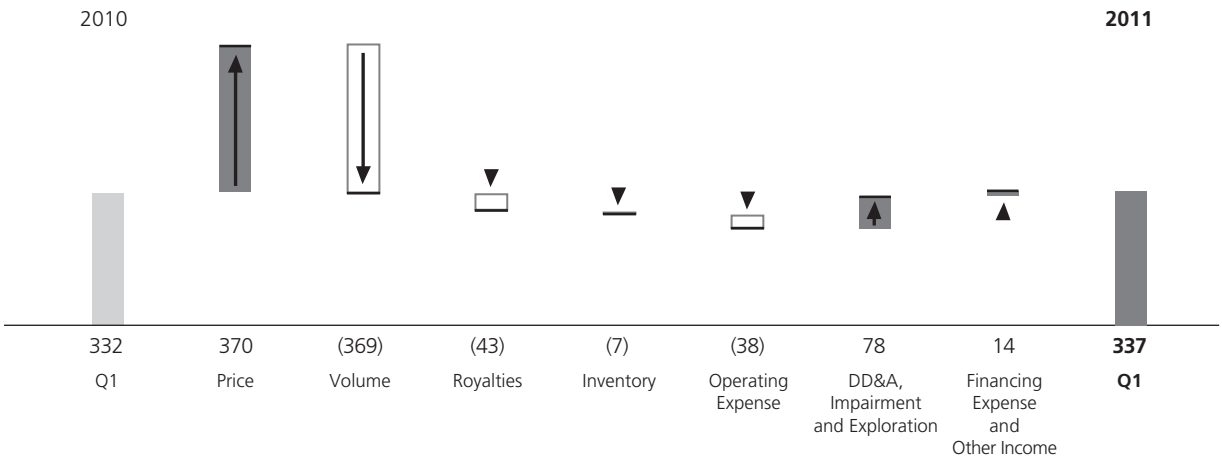
Operating Earnings Reconciliation

($ millions)	Three months ended March 31 2011	2010
Net (loss) earnings	**(186)**	528
Loss/(gain) on significant disposals	**81**	(204)
Impact of income tax rate adjustments on deferred income taxes	**442**	—
Redetermination of working interests in Terra Nova	**—**	8
Operating earnings[1]	**337**	332

(1) Non-GAAP measure. The company has restated prior year operating earnings for the transition to IFRS and for the removal of certain prior year operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Bridge Analysis of Operating Earnings

($ millions)



Production Volumes

	Three months ended March 31	
	2011	2010
Total production (mboe/d)	**240.7**	330.0
East Coast Canada (mbbls/d)	**65.0**	74.6
North Sea (mboe/d)	**65.7**	86.1
Other International (mboe/d)	**41.5**	47.1
North American Onshore (mmcfe per day (mmcfe/d))	**411**	733

In East Coast Canada, first quarter production decreased compared with the same quarter in 2010, primarily caused by partial shut-ins at Terra Nova to assess remediation options for the presence of hydrogen sulphide (H_2S) in certain wells. This decrease was partially offset by the increase in Suncor's working interest in Terra Nova from 33.990% to 37.675% that came into effect on January 1, 2011, and by additional volumes from the North Amethyst portion of the White Rose Extensions.

Production in the North Sea decreased in the first quarter of 2011, compared with the same quarter in 2010, primarily due to the prior period including 12.1 mboe/d associated with non-core asset dispositions completed in 2010. Persistent gas compression cooler outages have led to a decrease in production at Buzzard, where production volumes averaged 50.3 mboe/d in the first quarter of 2011, compared to 58.6 mboe/d in the first quarter of 2010.

Other International production decreased in the first quarter of 2011, compared with the same period in 2010. The company disposed of its Trinidad and Tobago assets in the third quarter of 2010, while new production from Syria only commenced in the second quarter of 2010. In Libya, production slowed in February 2011 and was completely shut-in by March, due to the civil unrest.

North American Onshore production decreased to 411 mmcfe/d in the first quarter of 2011 from 733 mmcfe/d in the first quarter of 2010, primarily due to non-core asset dispositions throughout 2010. Production from remaining properties in North America decreased 10% compared to the first quarter of 2010, due primarily to natural declines in reservoir performance.

Prices[1]

	Three months ended March 31	
	2011	2010
East Coast Canada ($/bbl)	**104.01**	78.69
North Sea ($/boe)	**98.28**	73.55
Other International ($/boe)	**91.92**	59.81
North American Onshore – natural gas ($/mcf)	**3.72**	5.32
North American Onshore – natural gas liquids and crude oil ($/bbl)	**77.85**	66.07

(1) Prices are calculated before royalties and net of transportation costs.

Average sales prices for crude oil and natural gas liquids in the first quarter of 2011 were significantly higher than the first quarter of 2010, due primarily to increasing benchmark prices for Brent crude. Average sales prices for natural gas from North American production decreased, due primarily to decreasing benchmark prices.

Royalties

After-tax royalties for Exploration and Production increased in the first quarter of 2011, compared to the same period in 2010. Suncor's operations in Libya and Syria are conducted pursuant to PSCs – royalty amounts presented reflect the difference between Suncor's working interest in the particular project and the net revenue attributable to Suncor under the terms of the applicable contract. In the first quarter of 2011, royalties in Libya increased as net revenue attributable to Suncor was lower, mainly due to the civil unrest and ensuing sanctions. East Coast Canada royalties were lower in the first quarter of 2011 than in the same period in 2010, with lower production volumes more than offsetting higher prices. North American Onshore royalties were also lower than in the same period in 2010, primarily because of asset dispositions and lower sales prices. The company does not pay royalties on U.K. production.

Expenses and Other Factors

Operating expenses were higher in the first quarter of 2011 than in the first quarter of 2010, mainly due to costs associated with the closure of an office in London, England in March and higher share-based compensation expense triggered primarily by the increase in the company's stock price.

DD&A decreased in the first quarter of 2011 compared with the same period in 2010, primarily due to lower production volumes resulting from 2010 asset dispositions. Exploration expense also decreased in the first quarter of 2011 as activities in Libya were suspended due to the civil unrest.

Asset Dispositions

On March 31, 2011, the company completed its sale of non-core U.K. offshore assets (primarily Scott and Triton) that had an effective date of July 1, 2010, for net proceeds of £105 million (Cdn$164 million), subject to closing adjustments. Net proceeds were reduced significantly by operations subsequent to the effective date that were recorded as part of the company's earnings up to the closing date. These properties contributed production of 15.4 mboe/d in the first quarter of 2011.

During 2010, the company divested other North Sea assets:

- A portion of the sale of the non-core U.K. offshore assets was completed in the fourth quarter of 2010 for net proceeds of £55 million (Cdn$86 million).
- On August 13, 2010, the company completed the sale of its shares in Petro-Canada Netherlands BV for net proceeds of €316 million (Cdn$420 million) with an effective date of January 1, 2010.

North Sea assets that the company sold in 2010 and 2011 contributed production of 27.5 mboe/d in the first quarter of 2010.

On August 5, 2010, the company completed the sale of its assets in Trinidad and Tobago for net proceeds of US$378 million (Cdn$383 million) with an effective date of January 1, 2010. These assets contributed production of 11.7 mboe/d in the first quarter of 2010.

During 2010, the company divested a number of non-core natural gas assets from its North American Onshore operations:

- On March 1, 2010, the company sold substantially all of its producing assets in the U.S. Rockies for net proceeds of US$481 million (Cdn$502 million). The remaining U.S. Rockies upstream assets were sold shortly thereafter.
- On March 31, 2010, the company completed the sale of properties located in northeast B.C., known as Jedney/Blueberry, for net proceeds of $383 million.
- On May 31, 2010, the company completed the sale of properties located in central Alberta, known as Rosevear and Pine Creek, for net proceeds of $229 million.
- On August 31, 2010, the company completed the sale of properties located in west central Alberta, known as Bearberry and Ricinus, for net proceeds of $275 million.
- On September 30, 2010, the company completed the sale of properties located in southern Alberta, known as Wildcat Hills, for net proceeds of $351 million.

These natural gas properties contributed production of 277 mmcfe/d in the first quarter of 2010.

The company plans to continue divesting non-core properties from its North American Onshore operations. As at March 31, 2011, the carrying value of assets classified as held for sale was $94 million.

Planned Maintenance Events

The 15-week dockside maintenance program originally planned for Terra Nova in 2011 is expected to be delayed until 2012, so that plans to resolve H_2S issues may be implemented concurrently. Terra Nova still plans to undergo a four-week annual maintenance outage during the third quarter of 2011 and has contingency plans ready in the event that swivel performance requires an additional outage.

White Rose has a 16-day planned maintenance event scheduled for July 2011, though work is ongoing to reduce the length of this event.

The tie-in of the fourth platform at Buzzard has been temporarily delayed and is expected to be completed in the second quarter of 2011. A three-week annual maintenance program at Buzzard is expected in the third quarter of 2011.

Terra Nova Collective Bargaining

In the first quarter of 2011, the company negotiated a collective agreement with union leadership at Terra Nova. The agreement has not been ratified by the union membership. Suncor is currently evaluating its next steps.

Political Unrest in the Middle East and North Africa

In late February, political violence in Libya resulted in Suncor evacuating its expatriate personnel and implementing other security measures for the safety of Libyan national staff, contractors and other service providers. In early March, as the political violence worsened, production volumes in Libya were shut-in. Suncor continues to monitor the situation in Libya and to date has taken all reasonable steps to ensure the safety of its people and preserve the value of its assets and operations, and maintain compliance with the company's Principles for Responsible Investment and Operations, which define Suncor's human rights values and policies in the areas in which we operate. As part of its normal course of operations, Suncor carries risk mitigation instruments in the aggregate amount of approximately $400 million (pre-tax).

On March 18, 2011, Suncor declared force majeure under its EPSAs. As at March 31, 2011, Suncor had no cash inflows and minimal cash outflows pertaining to its operations in Libya. The carrying value of Suncor's net assets in Libya at March 31, 2011 was approximately $900 million. Suncor's operations in Libya represented approximately 1% of the company's consolidated operating earnings for the year ended December 31, 2010 and 3% of the company's consolidated assets as at December 31, 2010.

As at March 31, 2011, Suncor had not recorded any impairment adjustments related to these assets. Suncor is continuing to evaluate and assess its assets in Libya for potential impairment. Should the current situation in Libya be resolved in a manner such that the sale of production resumes expediently and without significant remedial expenditure, the value of Suncor's net assets in Libya will not be impaired. However, should the current situation persist or worsen, such that Suncor is unable to resume operations in the near term or without significant remedial expenditure, Suncor believes its assets in Libya could be impaired in the future.

In response to the political violence in Libya, the United Nations, the European Union and the Canadian and U.S. governments imposed sanctions on transactions with Libya and corporations controlled by the Libyan government, including the National Oil Corporation – Suncor's joint venture partner – and Harouge Oil Operations BV – the joint venture operating company. Suncor is complying with the terms of all sanctions in jurisdictions relevant to the company's operations.

More recently, unrest has also surfaced in certain regions of Syria. To date, there has been no direct impact to Suncor's operations as a consequence of this unrest. The company continues to monitor the situation closely with a priority placed on the safety of its personnel and the security of its assets.

Refining and Marketing

Financial Highlights

	Three months ended March 31	
($ millions, unless otherwise noted)	**2011**	2010
Operating revenues	**6 079**	4 818
Net earnings and operating earnings[1]	**627**	147
Refining and product supply	**546**	80
Marketing	**81**	67
Cash flow from operations[1]	**929**	328
Total refined product sales (thousands of m^3/d)	**84.9**	82.2
Crude oil processed (thousands of m^3/d)	**68.4**	64.5

(1) Operating earnings and cash flow from operations are non-GAAP measures. The company has restated prior year operating earnings for the transition to IFRS and for the removal of certain prior year operating earnings adjustments. See also the Non-GAAP Financial Measures Advisory section of this MD&A.

Refining and Marketing had net earnings and operating earnings of $627 million in the first quarter of 2011, compared with net earnings and operating earnings of $147 million in the first quarter of 2010.

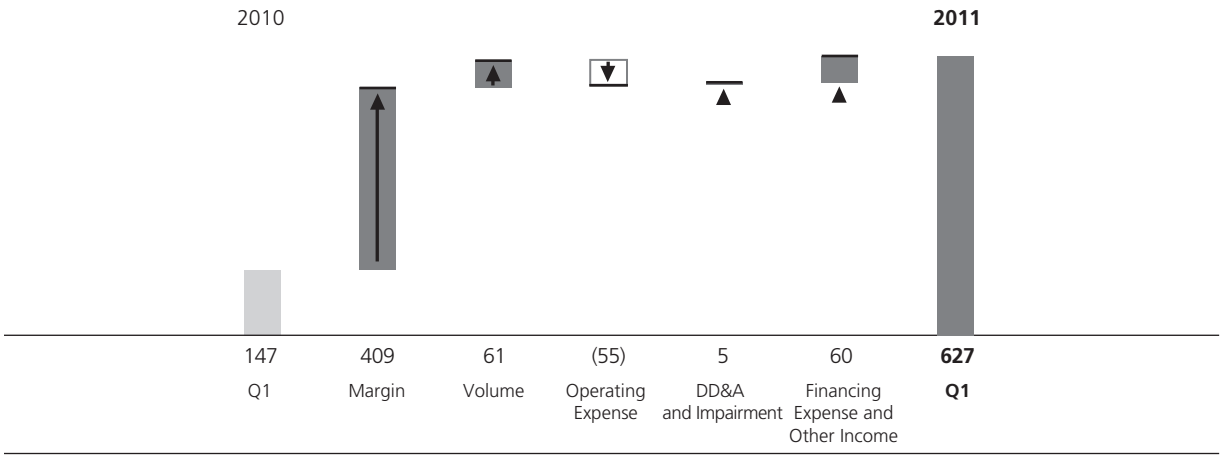
Refining and product supply activities contributed $546 million to operating earnings in the first quarter of 2011, bolstered by strong cracking margins in all markets and widening light/heavy crude differentials. Marketing activities contributed $81 million to operating earnings in the first quarter of 2011, an increase over the same period in 2010, mainly due to higher sales volumes and margins in the wholesale and lubricants channels.

Cash flow from operations was $929 million in the first quarter of 2011, compared to $328 million in the first quarter of 2010, and increased primarily due to higher margins and the other factors affecting operating earnings.

Operating Earnings

Bridge Analysis of Operating Earnings

($ millions)



Volumes

	Three months ended March 31	
	2011	2010
Refined product sales (thousands of m^3/d)		
Gasoline		
Eastern North America	**21.1**	21.0
Western North America	**17.0**	18.1
	38.1	39.1
Distillates		
Eastern North America	**13.4**	12.3
Western North America	**20.8**	16.9
	34.2	29.2
Other, including petrochemicals	**12.6**	13.9
Total refined product sales	**84.9**	82.2
Refinery utilization (%)		
Eastern North America	**97**	91
Western North America	**97**	92
Crude oil processed (thousands of m^3/d)		
Eastern North America	**33.1**	31.0
Western North America	**35.3**	33.5
Total crude oil processed	**68.4**	64.5

Total sales of refined petroleum products averaged 84,900 m^3/d in the first quarter of 2011, compared to 82,200 m^3/d in the first quarter of 2010. The economic recovery led to increases in sales volumes of lubricants, as well as distillates in Western Canada through the company's wholesale network. These increases were partially offset by decreases in retail

sales volumes that were mainly due to the site divestments completed throughout 2010 that were mandated by the Canadian Competition Bureau as a result of the merger.

Refinery utilization in Eastern North America averaged 97% in the first quarter of 2011. The Montreal refinery ran at record rates in the first quarter, reflecting improvements from the company's focus on reliable operations, but also increased to make up for reduced throughput at the Sarnia refinery. Logistical constraints on the Enbridge pipeline system are negatively impacting the Sarnia refinery, which continues to endure ongoing crude availability issues due to the apportionment of pipeline space and crude contamination issues caused by the commingling of Sarnia feedstock with heavier crudes.

Refinery utilization in Western North America averaged 97% in the first quarter of 2011. The increase over the same period in 2010 was mainly due to improved reliability at the Edmonton refinery that the company has shown since the middle of last year, resulting from operational improvements following the refinery conversion project in 2009, and the company's need to build inventory levels heading into planned maintenance events at both refineries in the second quarter of 2011.

Prices and Margins

Gross margins increased significantly during the first quarter of 2011 and were much higher than in the first quarter of 2010, as cracking margins were well above historical averages. Earnings also benefited from the effects of a rising price environment, as inventories produced during periods of lower feedstock costs were sold in the current period at increased prices that reflected current market conditions.

Due to increasing prices for refined products, the company's Sarnia, Edmonton and Commerce City refineries, which all run crude feedstock priced off of WTI, benefited further from the lower relative feedstock costs reflected by WTI trading at a significant discount to Brent. These refineries also benefited further from widening Western Canada light/heavy differentials and sweet/sour synthetic crude differentials. Refining margins at the Montreal refinery were also strong, with cracking margins more than offsetting the increase in feedstock costs caused by the increase in prices for Brent crude.

Expenses and Other Factors

Operating expenses were slightly higher in 2011, compared with 2010, due to higher variable transportation costs associated with the increase in sales volumes, and higher share-based compensation expense that was triggered primarily by the increase in the company's stock price.

Operating earnings were also positively impacted by a gain pertaining to the company's investments in marketing entities and a decrease in the effective tax rate for the segment as a result of a higher proportion of taxable earnings in Canada.

Planned Maintenance Events

The second quarter of 2011 for Refining and Marketing includes planned maintenance events at three of the company's four refineries.

On March 20, 2011, the company began planned maintenance at the Sarnia refinery that involved the partial shutdown of the refinery's operating units, including the hydrocracking unit. This work occurred over a five-week period ending on May 1. The company increased throughput levels at the Montreal refinery to help offset the loss of production related to this maintenance event.

On March 19, 2011, the company began planned maintenance at the Commerce City refinery that involved the shutdown of two out of three crude distillation units and the associated processing units. This work was completed prior to the end of April.

In late April 2011, the company commenced a six-week program of planned maintenance at the Edmonton refinery, which includes the shutdown of the heavy crude unit, two hydrotreating units and the delayed coker unit. This work has been co-ordinated with the planned maintenance at Upgrader 2 in Oil Sands to minimize the impact of each plant's outages on the other.

For planned maintenance events, the company mitigates the impact of lost production on customers by building inventory levels prior to the event and by entering into transactions to ensure the availability of additional refined products.

Corporate, Energy Trading and Eliminations

Financial Highlights

	Three months ended March 31	
($ millions, unless otherwise noted)	**2011**	2010
Net (loss) earnings	**(18)**	15
Operating earnings (loss)[1]		
Renewable energy	**15**	14
Energy trading	**39**	(8)
Corporate	**(189)**	(208)
Group eliminations	**(45)**	3
	(180)	(199)
Cash flow used in operations[1]	**(256)**	(317)
Power generation marketed (gigawatt hours)	**55**	45
Ethanol production (thousands of m^3)	**81.7**	53.4

(1) Non-GAAP measures. Operating earnings is reconciled to net earnings below. The company has restated prior year operating earnings for the transition to IFRS and for the removal of certain prior year operating earnings adjustments. See also the Non-GAAP Financial Measures Advisory section of this MD&A.

The net loss for Corporate, Energy Trading and Eliminations in the first quarter of 2011 was $18 million, compared with net earnings of $15 million in the first quarter of 2010. In the first quarter of 2011, the US$/Cdn$ exchange rate increased from 1.01 to 1.03, resulting in an after-tax unrealized foreign exchange gain on U.S. dollar denominated long-term debt of $162 million, compared with an after-tax gain of $230 million in the first quarter of 2010, when the US$/Cdn$ exchange rate increased from 0.96 to 0.98.

The operating loss for Corporate, Energy Trading and Eliminations in the first quarter of 2011 of $180 million was less than the operating loss of $199 million in the first quarter of 2010, primarily due to a lower operating loss in Corporate and higher earnings from energy trading activities.

Operating Earnings

Operating Earnings Reconciliation

($ millions)	Three months ended March 31 2011	2010
Net (loss) earnings	**(18)**	15
Unrealized foreign exchange gain on U.S. dollar denominated long-term debt	**(162)**	(230)
Merger and integration costs	**—**	16
Operating loss[1]	**(180)**	(199)

(1) Non-GAAP measure. The company has restated prior year operating earnings for the transition to IFRS and for the removal of certain prior year operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Renewable Energy

Suncor's renewable energy assets contributed operating earnings of $15 million in the first quarter of 2011, which was comparable to operating earnings of $14 million in the first quarter of 2010.

At the end of January 2011, Suncor completed the expansion of its ethanol plant in Ontario, which increased production capacity from 200 million litres per year to 400 million litres per year.

Energy Trading

Energy trading activities contributed operating earnings of $39 million in the first quarter of 2011, compared with an operating loss of $8 million in the first quarter of 2010. The increase in earnings is due primarily to unrealized gains on trading strategies that purchase heavy crude oil in Alberta and transport it to markets with more favourable prices.

Corporate and Eliminations

Corporate had an operating loss of $189 million in the first quarter of 2011, compared with an operating loss of $208 million in the first quarter of 2010. Interest expense was lower as the company had less short-term debt throughout the first quarter of 2011 than in the same period in 2010, and capitalized more interest because of new spending on the Firebag Stage 4 expansion and other growth projects. The operating loss in the first quarter of 2010 also included captive insurance expenses pertaining to the 2009 Upgrader 2 fire. These decreases in operating loss were partially offset by an increase in share-based compensation expense that was triggered primarily by the increase in the company's stock price.

Group eliminations reflect the elimination of profit on crude oil sales from Oil Sands or East Coast Canada to Refining and Marketing. Consolidated profits are only realized when the refined products produced from internal purchases of crude feedstock have been sold to third parties. During the first quarter of 2011, $45 million of intersegment profit was eliminated. This figure increased compared with the first quarter of 2010, primarily because of the increase in crude oil prices.

CAPITAL INVESTMENT UPDATE

Suncor spent $1.602 billion on expenditures for property, plant and equipment and exploration and evaluation activities in the first quarter of 2011. Suncor's total capital budget for 2011 is $6.7 billion, including $2.8 billion directed towards growth projects.

Capital and Exploration Expenditures[1]

($ millions)	Three months ended **March 31 2011**
Oil Sands	**1 113**
Exploration and Production	**299**
Refining and Marketing	**128**
Corporate, Energy Trading and Eliminations	**62**
Total	**1 602**

(1) Amounts reflect cash payments for capital and exploration expenditures and include capitalized interest. The company's purchase of the interest in the Joslyn project from Total is not included because Suncor did not make payment for the purchase until April 2011.

The following sections providing capital investment updates for Suncor's segments contain forward-looking information. See the Advisory – Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

Oil Sands

Oil Sands capital and exploration expenditures were $1.113 billion in the first quarter of 2011 and included $200 million for the purchase of oil sands mining leases adjacent to the company's existing landholdings. Growth spending has been primarily focused on the construction of the Firebag Stage 3 and Stage 4 expansions, the implementation of TRO$_{TM}$ tailings reclamation technology across existing operations and the Millennium Naphtha Unit (MNU) project.

For Firebag Stage 3, first quarter expenditures were approximately $160 million and focused primarily on the construction of well pads and central plant and cogeneration facilities. In April 2011, the company started injecting steam into a well pad in the Firebag Stage 3 expansion. The company expects first oil production to be achieved in early July 2011. The company had previously disclosed that first oil would be achieved by the end of the second quarter. The ramp up period to achieve full production rates is approximately 24 months thereafter.

For Firebag Stage 4, first quarter expenditures were approximately $170 million and focused primarily on the construction of infrastructure, well pads, and central plant and cogeneration facilities. The company expects to begin production at the Stage 4 expansion late in the first quarter of 2013.

The company continued construction of the MNU. The project is scheduled to be completed by the end of 2011 and is expected to provide additional hydrotreating capacity to increase the percentage mix of sweet synthetic crude oil production.

The company anticipates expenditures for: (i) the Voyageur Upgrader to focus on the remobilization of the workforce, confirmation of current design and modification of project execution plans; (ii) the Fort Hills project to focus on design base memorandum engineering; and (iii) the Joslyn project to focus on geological, engineering, regulatory and environmental studies.

Exploration and Production

The Exploration and Production segment spent $299 million on capital and exploration expenditures in the first quarter of 2011, primarily on development drilling for Hibernia, Terra Nova and White Rose, exploratory drilling of the Ballicatters well offshore Newfoundland and the appraisal of the Beta discovery offshore Norway.

Suncor plans to begin drilling a production well at Terra Nova in the second quarter of 2011.

The Hibernia Southern Extension project received sanction in the first quarter of 2011. First oil from the extension is expected by the middle of 2011 from platform wells, with further capital expenditures throughout the year anticipated to be directed towards more development drilling and subsea infrastructure to facilitate increased future production when subsea wells come on-stream.

At White Rose, the drilling of development wells continues, with two to three wells planned for the year. White Rose received regulatory approval for a pilot project to be drilled from existing infrastructure to provide additional information about the West White Rose field that is part of the White Rose Extensions. The completion of the first of these two pilot wells and initial production volumes are expected in the second half of 2011, with water injection support expected to come on-stream in early 2012.

For Hebron, front-end engineering activities are continuing, and the project development plan application was submitted to the Canada Newfoundland and Labrador Offshore Petroleum Board on April 15, 2011.

In late 2010, a preliminary field development plan was filed for the Golden Eagle Area Development in the North Sea, which included stand-alone facilities designed for 70,000 boe/d of gross production. The field development decision is expected later in 2011. Suncor has a 26.69% interest in this development.

The company's exploration activities during the first quarter of 2011 included evaluating the Ballicatters exploration well offshore Newfoundland. In Norway, the company secured an offshore drilling rig for the fourth quarter of 2011 to drill a further appraisal well on the Beta discovery and meet its exploration commitment on the PL375B licence. In April 2011, Suncor was awarded new exploration licences (two operated and one non-operated) in the Norway portion of the North Sea. In-country exploration and seismic activities in Libya were suspended indefinitely as a result of the outbreak of civil unrest.

Refining and Marketing

Refining and Marketing spent $128 million on capital expenditures in the first quarter of 2011. Spending was primarily focused on planned maintenance events occurring in the second quarter.

Corporate, Energy Trading and Eliminations

Renewable Energy

Development of the 88 megawatt (MW) Wintering Hills wind project in southern Alberta and the 20 MW Kent Breeze wind project in Ontario continued in the first quarter of 2011. Capital expenditures focused on the acquisition of wind turbines and the construction of plant facilities and infrastructure. The company expects both projects to be completed in 2011.

Corporate

Corporate capital expenditures continue on initiatives to integrate pre-merger information systems onto one common platform.

FINANCIAL CONDITION AND LIQUIDITY

Indicators

($ millions, unless otherwise noted)	**March 31 2011**	December 31 2010
Working capital[(1)]	**383**	1 148
Short-term debt	**752**	1 984
Current portion of long-term debt	**514**	518
Long-term debt	**9 637**	9 829
Total debt	**10 903**	12 331
Less: Cash and cash equivalents	**3 465**	1 077
Net debt	**7 438**	11 254
Shareholders' equity	**36 400**	35 192
Total debt plus shareholders' equity	**47 303**	47 523
Total debt to total debt plus shareholders' equity (%)	**23**	26

(1) Current assets less current liabilities, excluding cash and cash equivalents, short-term debt, current portion of long-term debt and current assets and liabilities associated with assets held for sale.

	Twelve months ended March 31	
	2011	2010[1]
Return on Capital Employed (%)[2]		
Excluding major projects in progress	**12.5**	4.8
Including major projects in progress	**8.9**	3.4
Net debt to cash flow from operations (times)	**0.9**	4.3
Interest coverage on long-term debt (times)		
Net earnings[3]	**10.3**	5.0
Cash flow from operations[4][5]	**14.2**	7.2

(1) Inputs for metrics for the twelve months ended March 31, 2010 have been calculated based on three months of financial information prepared in accordance with IFRS (the three months ended March 31, 2010) and nine months of financial information prepared in accordance with Previous GAAP (the nine months ended December 31, 2009). See the Basis of Presentation section of this MD&A.

(2) Non-GAAP measure. The calculations for ROCE are detailed in the Non-GAAP Financial Measures Advisory section of this MD&A.

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

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

(5) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Capital Resources

Suncor's capital resources consist primarily of cash flow from operations and available lines of credit. Suncor's management believes the company will have the capital resources to fund its planned 2011 capital spending program and meet current and long-term working capital requirements through cash flow from operations, proceeds from the agreement with Total and other planned asset divestitures, and its available committed credit facilities. The company's cash flow from operations depends on a number of factors, including commodity prices, production and sales volumes, refining and marketing margins, operating expenses, taxes, royalties and foreign exchange rates. If additional capital is required, Suncor's management believes adequate additional financing will be available in debt capital markets at commercial terms and rates.

Financing Activities

The 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, 2011, Suncor's net debt was $7.438 billion, compared to $11.254 billion at December 31, 2010. Net debt decreased by $3.816 billion, largely due to an increase in cash and cash equivalents resulting from higher cash flow from operations and cash proceeds received from the closing of the transactions with Total. Cash and cash equivalents increased $2.388 billion during the first quarter of 2011, including the impact of the company reducing its short-term debt by $1.232 billion. In April 2011, Suncor settled the note payable to Total for the purchase of the interest in Joslyn. This payment had the effect of increasing net debt by $842 million. Unutilized lines of credit at March 31, 2011 were approximately $6.5 billion, compared to $5.3 billion at December 31, 2010, and increased due to the repayment of short-term debt.

The company plans to repay the $500 million Medium Term Notes due in August 2011 and maintain access to short-term commercial paper borrowing at competitive interest rates by keeping short-term debt at March 31, 2011 levels (approximately $750 million). The company plans to invest excess cash in short-term investments. The objectives of the company's short-term investment portfolio will be to ensure the preservation of capital, maintain adequate liquidity to meet cash flow requirements and deliver competitive returns consistent with the quality and diversification of investments

within acceptable risk parameters. The maximum weighted average term to maturity of the short-term investment portfolio will not exceed six months, and all investments will be with counterparties with investment grade debt ratings.

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 debt plus shareholders' equity. At March 31, 2011, total debt to total debt plus shareholders' equity was 23% (December 31, 2010 – 26%). The company is also currently in compliance with all operating covenants.

The preceding paragraphs contain forward-looking information. See the Advisory — Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

Credit Ratings

The following information regarding the company's credit ratings is provided as it relates to the company's cost of funds and liquidity and indicates whether or not the company's credit ratings have changed. In particular, the company's ability to access unsecured funding markets and to engage in certain collateralized business activities on a cost-effective basis is primarily dependent upon maintaining competitive credit ratings. A lowering of the company's credit rating may also have potentially adverse consequences for the company's funding capacity or access to the capital markets, may affect the company's ability, and the cost, to enter into normal course derivative or hedging transactions, and may require the company to post additional collateral under certain contracts.

All of the company's debt ratings are investment grade. The company's long-term senior debt ratings are BBB+, with a stable outlook from Standard & Poor's (S&P); A (low), with a stable trend from Dominion Bond Rating Service (DBRS); and Baa2, with a stable outlook from Moody's Investors Service. Suncor's current commercial paper ratings are A-1 (Low) from S&P and R-1 (low) from DBRS. These credit ratings have not changed from December 31, 2010.

Outstanding Shares

(thousands)	**March 31, 2011**
Common shares	**1 572 993**
Common share options – exercisable and non-exercisable	**64 675**
Common share options – exercisable	**43 451**

As at April 28, 2011, the total number of common shares outstanding was 1,573,257,188 and the total number of exercisable and non-exercisable common share options outstanding was 64,130,735. Once exercisable, each outstanding common share option is convertible into one common share.

Canadian Federal Budget Proposal

A Canadian federal budget was introduced on March 22, 2011; however, opposing parties defeated the government and forced an election for May 2, 2011. The budget included several changes that could have a significant impact on Suncor, including the limitation of deferral opportunities for corporate partnerships, the change in the future treatment of oil sands lease purchases to Canadian oil and gas property expense from Canadian development expense and the change in future treatment of pre-production development expenses for oil sands mines to Canadian development expense from Canadian exploration expense. A better understanding of the effects of the budget is subject to a review of the actual legislation, if and when the budget is passed. The company's preliminary assessment is that, if passed, the budget will decrease cash

flow from operations by accelerating the payment of cash income taxes, but will not have a significant impact on net earnings.

Contractual Obligations, Commitments and Guarantees

In the normal course of business, the company is obligated to make future payments, including contractual obligations and non-cancellable commitments. Suncor has included these items in the Aggregate Contractual Obligations section of its 2010 MD&A, which is herein incorporated by reference.

Since December 31, 2010, there have been no material changes to amounts presented in the Aggregate Contractual Obligations table, except that the time frame for the completion of exploration commitments (US$335 million) and payment of other long-term liabilities (US$290 million) pertaining to the EPSAs in Libya may be deferred until later years as a result of the civil unrest and sanctions, and except for the reclassification of $460 million from operating lease agreements to capital lease payments as a result of the company's transition to IFRS.

FINANCIAL INSTRUMENTS

Suncor periodically enters into derivative contracts such as forwards, futures, swaps, options and costless collars to manage exposure to fluctuations in commodity prices and foreign exchange rates, and to optimize the company's position with respect to interest payments. The company also uses physical and financial energy derivatives to earn trading revenues.

For more information on Suncor's financial instruments and the related financial risk factors, see note 21 of the audited Consolidated Financial Statements for the year ended December 31, 2010, which note herein is incorporated by reference.

Energy Trading and Risk Management Activities

Suncor uses crude oil, natural gas and refined product derivative contracts to earn supply and trading revenues. The results of these supply and trading activities are reported as Energy supply and trading activity income and expenses in the Consolidated Statements of Comprehensive Income.

Suncor also uses derivative contracts to hedge risks related to purchases and sales of commodities, to manage exposure to interest rates, and to hedge risks specific to individual transactions. To comply with IFRS, gains or losses on risk management derivatives are now recorded in Interest and other income in the Consolidated Statements of Comprehensive Income. Under Previous GAAP, these gains and losses were recorded in the same caption as the related transaction. There are no significant risk management derivative contracts outstanding as at March 31, 2011.

The change in fair value of derivatives pertaining to energy trading and risk management activities during the first quarter of 2011 was as follows:

($ millions)	
Fair value of derivative contracts outstanding at December 31, 2010	(74)
Fair value of derivative contracts realized during the period	**69**
Change in fair value during the period	**(14)**
Fair value of derivative contracts outstanding at March 31, 2011	**(19)**

The fair value of derivatives pertaining to energy trading and risk management activities are recorded in the Consolidated Balance Sheets as follows:

($ millions)	**March 31 2011**	December 31 2010
Accounts receivable	**90**	19
Accounts payable and accrued liabilities	**(109)**	(93)
	(19)	(74)

Accounting for Fair Value Hedges

As at March 31, 2011, the company had interest rate swaps relating to $200 million of its fixed-rate debt for Medium Term Notes due August 2011 classified as fair value hedges. The fair value of these swaps was $4 million at March 31, 2011, and is recorded in Accounts receivable in the Consolidated Balance Sheets.

Risks Associated with Derivative Financial Instruments

Suncor's price risk management strategies are subject to periodic management reviews to determine appropriate hedge requirements based on the company's tolerance for exposure to market volatility, as well as the need for stable cash flow to finance future growth.

Suncor 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. The company minimizes 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. Suncor's exposure is limited to those counterparties holding derivative contracts with net positive fair values at the reporting date.

Energy trading activities are governed by a separate risk management group that reviews and monitors practices and policies, and provides independent verification and valuation of these activities.

RISK FACTORS

The company's financial and operational performance is potentially affected by a number of factors, including but not limited to, the volatility of commodity prices and exchange rate fluctuations; government regulation, including changes to royalty and income tax legislation; environmental regulation, including changes to climate change and reclamation legislation; risks associated with operating in foreign countries, including geopolitical and other political risks; operating hazards and other uncertainties, including extreme weather conditions, fires, explosions and oil spills; risks associated with the execution of major projects; reputational risk; permit approval; labour and materials supply; and other issues discussed within the Advisory – Forward-Looking Information section of this MD&A. A more detailed discussion of the risk factors affecting the company is presented in the Risk Factors section of Suncor's 2010 MD&A, which is herein incorporated by reference. See also the Control Environment Section of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with GAAP requires management to make estimates, judgments and assumptions that affect reported assets, liabilities, revenues and expenses, gains and losses, and disclosures of contingencies. These estimates and assumptions are subject to change based on experience and new information. Critical accounting estimates are those that require management to make assumptions about matters that are highly uncertain at the time the estimate is made. Critical accounting estimates are also those estimates, which, where a different estimate could have been used or where changes in the estimate that are reasonably likely to occur, would have a material impact on the company's financial condition, changes in financial condition or financial performance. Critical accounting estimates are reviewed annually by the Audit Committee of the Board of Directors. The following are the critical accounting estimates used in the preparation of Suncor's March 31, 2011 unaudited Interim Consolidated Financial Statements.

Oil and Gas Reserves and Resources

Measurements of depletion, depreciation, amortization, impairment and decommissioning and restoration obligations are determined in part based on the company's estimate of oil and gas reserves and resources. Although not reported as part

of the company's Consolidated Financial Statements, these estimates of reserves and resources can have a significant impact on the Consolidated Financial Statements.

The estimation of reserves is a subjective process and involves the exercise of professional judgment. Reserves and resources were evaluated or reviewed as at December 31, 2010 by independent qualified reserves evaluators in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. The reserves and resources estimates are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook.

Oil and gas reserves and resources estimates are based on a range of geological, technical and economic factors, including projected future rates of production, estimated commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Assumptions reflect market and regulatory conditions existing at December 31, 2010, which could differ significantly from other points in time throughout the year or in future periods.

Oil and Gas Activities

The company is required to use judgment when designating the nature of oil and gas activities as exploration, evaluation, development or production, and when determining whether the initial costs of these activities are capitalized.

Exploration and Evaluation Costs

The costs of drilling exploratory wells are initially capitalized pending the evaluation of commercially recoverable resources. The determination that commercial resources have been discovered requires both judgment and industry experience. If a judgment is made that there are no commercially recoverable reserves, the associated exploration costs are charged to Exploration expense. Evaluation costs incurred when management is assessing whether there are commercially recoverable resources and designing development and front-end engineering plans are capitalized. Capitalized costs associated with exploration and evaluation assets are subject to ongoing technical, commercial and management review to confirm the continued intent to develop and extract the underlying resources. When management is making this assessment, changes to project economics, quantities of resources, expected production techniques, unsuccessful drilling, and estimated production costs and capital expenditures are important factors. If a judgment is made that extraction of the resources is not commercially viable, the associated exploration and evaluation costs are impaired and charged to net earnings.

Development Costs

Management uses judgment to determine when Exploration and evaluation assets are reclassified to Property, plant and equipment. This decision considers several factors, including the existence of reserves, the receipt of the appropriate approvals from regulatory bodies and the company's internal project approval processes. After an oil and gas property is reclassified to Property, plant and equipment, all subsequent development costs are capitalized.

Impairment of Assets

A cash-generating unit (CGU) is the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of the company's assets into CGUs requires significant judgment with respect to the integration between assets, the use of shared infrastructure, the existence of active markets for the company's products and the way in which management monitors operations.

At the end of each reporting period, the company is required to identify events or conditions that indicate that the net carrying value of a CGU in the Consolidated Balance Sheets might be impaired. If any such indication exists, the company must complete an impairment assessment for the CGU. A CGU is impaired when the net carrying value of the CGU exceeds management's estimate of the recoverable amount of the CGU, which is the higher of the CGU's fair value less costs to sell and its value-in-use. Fair value less costs to sell is the amount obtainable from the sale of the CGU in an arm's-length transaction between knowledgeable, willing parties, less costs of disposal. In determining fair value less costs

to sell, recent market transactions are taken into account if available; however, in the absence of such transactions, an appropriate valuation model is used. Value-in-use is assessed using the present value of the future cash flows that the company expects to derive from the CGU. Where management determines that a CGU is impaired, the net carrying value of the CGU is reduced to the estimated recoverable amount, with the difference reported as part of Depreciation, depletion, amortization and impairment expense.

Regardless of any indication of impairment, the company must complete an annual impairment assessment for any CGU, or group of CGUs, whose net carrying value includes indefinite-life intangible assets or an allocation of goodwill. For Suncor, this includes impairment assessments of the Oil Sands segment and the Refining and Marketing segment.

At the end of each reporting period, the company must also assess if there are indicators that conditions causing a previous impairment have reversed. Where new estimates of recoverable amount exceed net carrying value, previously recorded impairment adjustments are reversed, up to the amount of the original impairment. An impairment of goodwill cannot be reversed. As at March 31, 2011, the company had accumulated $114 million of previous impairments on assets in the Exploration and Production segment. These impairments have been adjusted from amounts previously reported because of the transition to IFRS.

For Suncor, the estimated recoverable amount of a CGU is predominantly determined using discounted net future cash flow models. The key assumptions the company uses for estimating future cash flows are future commodity prices, expected production volumes, future operating and development costs, and refining margins. The estimated useful life of the CGU, the timing of future cash flows and discount rates are also important assumptions made by management. Changes to these assumptions will affect the recoverable amount of a CGU and may require a material impairment to the net carrying value of that CGU.

The company also assesses the impairment of assets when they are classified as held for sale or when they are reclassified from Exploration and evaluation assets to Property, plant and equipment in the Consolidated Balance Sheets. Assets held for sale are measured at the lower of net carrying value and fair value less costs to sell, which in this situation may also be determined based on expected sale proceeds when an offer has been received.

IFRS Transition Exemption

The company applied an IFRS transition exemption to record certain assets at fair value less costs to sell on the date of transition. The exemption was applied to refinery assets located in Eastern Canada and certain natural gas assets in Western Canada, and resulted in a total reduction of $906 million in the net carrying value of these assets. These adjustments are not impairments and cannot be reversed because they were applied as part of the IFRS transition. The company's estimates of fair value less costs to sell for these assets required management to make judgments and use assumptions retrospective to the transition date that were similar to those described above.

Fair Value of Financial Instruments

To estimate the fair value of financial instruments, the company uses quoted market prices when available, or models that use observable market data. In addition to market information, Suncor incorporates transaction-specific details that market participants would use in a fair value measurement, including the impact of non-performance risk. Inputs used in determining fair value are characterized 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.

Provisions for Decommissioning and Restoration Costs

The company recognizes liabilities for the future decommissioning and restoration of property, plant and equipment, including, but not limited to, tailings ponds, producing well sites, and crude oil and natural gas processing plants. The provision for such a liability is recognized only to the extent that there is a legal obligation associated with the retirement of an asset that the company is required to settle as a result of an existing or enacted law, statute, ordinance, written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel.

These provisions are based on estimated costs, which take into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible future use of the site. Since these estimates are specific to the assets involved, there are many individual judgments and assumptions underlying Suncor's total provision. Actual costs are uncertain and estimates can vary as a result of changes to relevant laws and regulations, the emergence of new technology, operating experience and changes in prices. The expected timing of future decommissioning and restoration activities may change due to certain factors, including oil and gas reserves life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

When these provisions are initially recognized, an equal amount is capitalized as part of the cost of the associated asset and is amortized to expense over the life of the asset.

The fair value of these provisions is estimated by discounting the expected future cash flows using the company's credit-adjusted risk-free interest rate. In subsequent periods, the provision is adjusted for the passage of time by charging an amount to Accretion of liabilities in Financing expenses, based on the discount rate.

Other Provisions

An onerous contract is one in which the unavoidable costs of meeting the obligations under the contract exceed the economic benefits expected to be received under it.

A constructive obligation is one where Suncor, by an established pattern of past practice, published policies, or a sufficiently current statement, has indicated that it will accept certain responsibilities and has created a valid expectation in other parties that it will discharge those responsibilities.

The determination of other provisions, including, but not limited to, provisions for royalty disputes, onerous contracts, litigation and constructive obligations, is a complex process that involves judgments about the outcomes of future events, the interpretation of laws and regulations, expected future cash flows and discount rates.

The company is involved in litigation and claims in the normal course of operations. As at March 31, 2011, management believes the result of any settlements related to such litigation or claims would not materially affect the financial position of the company.

Employee Future Benefits

The company provides benefits to employees and retired employees, including pensions and other post-retirement benefits. The obligations and costs of defined benefit pension and other post-retirement benefit plans are determined based on actuarial valuation methods and assumptions. Assumptions typically used in determining these amounts include, as applicable, rates of employee turnover, future claim costs, discount rates, future salary and benefit levels, the return on plan assets, mortality rates and future medical costs. The accrued net benefit liability is reported as Other long-term liabilities in the Consolidated Balance Sheets.

The fair value of plan assets is determined using market values. The estimated rate of return on plan assets in the portfolio considers the current level of returns on fixed income assets, the historical level of risk premium associated with other

asset classes and the expected future returns on all asset classes. The discount rate assumption is based on the year-end interest rates for high quality bonds that mature at times concurrent with the company's benefit obligations. The estimated rate for compensation increases is based on management's judgment.

Actuarial valuations are subject to management's judgment. Actuarial gains and losses comprise changes to assumptions related to discount rates, expected return on plan assets and annual rates for compensation increases. They are accounted for on a prospective basis and may have a material impact on the amounts presented. Actuarial gains and losses are recognized in Other comprehensive income in the Consolidated Statements of Comprehensive Income in the period incurred.

Income Taxes

The determination of the company's income tax provision is an inherently complex process, requiring management to interpret continually-changing regulations and to make other judgments, including those about deferred income taxes that are discussed below.

Management believes that adequate provisions have been made for all income tax obligations, although the results of audits and reassessments and changes in the interpretations of standards may result in a material increase or decrease in the company's assets, liabilities and net earnings.

Deferred Income Taxes

A taxable or a deductible temporary difference exists when there is a difference between the carrying value of an asset or liability and its respective tax basis. The reversal of deductible temporary differences results in deductible amounts when determining taxable income in future periods. The reversal of taxable temporary differences results in taxable amounts when determining taxable income of future periods.

Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the company's estimate, the ability of the company to realize the deferred tax assets could be impacted.

Deferred tax liabilities are recognized when there are taxable temporary differences that will reverse and result in a future outflow of funds to a taxation authority. The company records a provision for the amount that is expected to be settled, which requires the application of judgment as to the ultimate outcome. Deferred tax liabilities could be impacted by changes in the company's estimate of the likelihood of a future outflow, the expected settlement amount, and the tax laws in the jurisdictions in which the company operates.

CHANGES IN ACCOUNTING POLICIES

Suncor's significant accounting policies are described in note 3 to the March 31, 2011 unaudited Interim Consolidated Financial Statements.

Adoption of IFRS

Effective January 1, 2011, the company began reporting under IFRS. The accounting policies referenced above have been applied in preparing the financial results for the three-month periods ended March 31, 2011 and 2010, the financial results for the year ended December 31, 2010, and the company's opening balance sheet as at January 1, 2010. A detailed reconciliation of amounts reported under Previous GAAP to those presented in this MD&A is provided in note 5 to the unaudited Interim Consolidated Financial Statements.

The following table provides a summary reconciliation of consolidated net earnings reported under Previous GAAP to that reported under IFRS:

($ millions)	Three months ended March 31 2010	Year ended December 31 2010
Net earnings, as reported under Previous GAAP	716	3 571
Adjustments to net earnings:		
Depreciation, depletion, amortization and impairment	64	274
Gain on disposal of assets	13	54
Other	8	17
Provision for deferred income taxes	(22)	(87)
Net earnings, as reported under IFRS	779	3 829

The transition to IFRS included adjustments of $1.632 billion that decreased the carrying amount of Suncor's Property, plant and equipment as at January 1, 2010. Suncor applied an IFRS exemption that permitted it to revalue the amount of decommissioning and restoration costs included in the carrying value of the related assets. Suncor also applied an IFRS exemption that permitted it to record certain assets at fair value less costs to sell on the date of transition. The increase in net earnings under IFRS, compared to Previous GAAP, is primarily a result of applying these exemptions to decrease the company's carrying value of Property, plant and equipment, and consequently decrease subsequent depreciation of those assets and increase any gains or decrease any losses on the disposal of those assets.

The transition to IFRS also required that the company adopt accounting policies that are different to those previously reported. Changes to accounting policies that may have a significant impact on the company's net earnings or presentation of net earnings include:

- Impairment of assets – Under Previous GAAP, an asset was not impaired if estimates of its recoverable amount using undiscounted expected future cash flows exceeded its net carrying value. Under IFRS, discounted cash flows must form the estimate of recoverable amount, essentially making it more likely that asset impairments will be required.
- Classification of discontinued operations – Under Previous GAAP, most of the company's 2010 asset dispositions met the definition of discontinued operations, whereas under IFRS only an immaterial amount of the 2010 dispositions met the IFRS definition of discontinued operations. As a result, the company has restated amounts previously reported and is not presenting any discontinued operations for 2010 comparative figures. The company does not expect that any of the non-core properties it is planning to divest from its North American Onshore operations will meet the IFRS definition for discontinued operations.

The company's IFRS conversion project is winding down. Comprehensive training and implementation of business process changes will continue into the second quarter of 2011.

Recently Announced Accounting Standards

As part of the International Accounting Standards Board (IASB) project to replace IAS 39 – *Financial Instruments: Recognition and Measurement*, in November 2009 the IASB issued the first phase of IFRS 9 – *Financial Instruments*, which introduces new requirements for the classification and measurement of financial assets. The new standard was further revised in October 2010 to include requirements regarding the classification and measurement of financial liabilities. The standard is applicable for annual periods starting on or after January 1, 2013. The full impact of the changes in accounting for financial instruments will not be known until the IASB project has been completed.

CONTROL ENVIRONMENT

Based on their evaluation as of March 31, 2011, 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, 2011, 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, 2011 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.

As a result of political violence in Libya, Suncor is not able to monitor the status of all of its facilities, including whether certain facilities have suffered damages. Suncor has assessed and is continually monitoring the control environment in Libya and does not consider the changes to have a material impact on the company's overall internal control over financial reporting.

The company continues to integrate Petro-Canada's historical internal controls over financial reporting with its own internal controls 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 2011.

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.

CORPORATE GUIDANCE

Suncor has updated its 2011 corporate guidance that was stated in its December 17, 2010 press release. The press release of Suncor dated May 3, 2011, which is also available on www.sedar.com, provides the updated corporate guidance and additional details describing why the guidance was revised.

NON-GAAP FINANCIAL MEASURES ADVISORY

Certain financial measures in this MD&A – namely operating earnings, cash flow from operations, ROCE and Oil Sands cash operating costs – are not prescribed by GAAP. These non-GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. These non-GAAP financial measures are included because management uses the information to analyze operating performance, leverage and liquidity. Therefore, these non-GAAP financial measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Oil Sands Cash Operating Costs

Oil Sands cash operating costs are reconciled in the Segmented Results and Analysis – Oil Sands section of this MD&A.

Operating Earnings

Operating earnings is a non-GAAP measure that adjusts net earnings for significant items that are not indicative of operating performance that management believes reduces the comparability of the underlying financial performance between periods. Management uses operating earnings to evaluate operating performance, because management believes it provides better comparability between periods. All reconciling items are presented on an after-tax basis.

Prior period operating earnings have been restated in this MD&A. In the fourth quarter of 2010, the company reflected two one-time earnings adjustments – the modification of the bitumen valuation methodology and the gain on the redetermination of working interests in the Terra Nova oil field – by restating operating earnings for all relevant prior quarters. In the first quarter of 2011, three operating earnings adjustments – mark-to-market valuation of stock-based compensation, project start-up costs and costs related to the deferral of growth projects – were eliminated from the operating earnings reconciliation due to their relatively minor impact on operating earnings in 2011 and 2010. Less significant individual gains and losses on disposal were also removed from operating earnings reconciling items reported in prior periods. Finally, adjustments to net earnings for the transition to IFRS also had an impact on operating earnings and existing operating earnings adjustments.

The following is a reconciliation of operating earnings as reported in the company's previous reports to operating earnings as reported in this MD&A:

Three months ended March 31, 2010 ($ millions)	Oil Sands	Exploration and Production	Refining and Marketing	Corporate, Energy Trading and Eliminations	Total
Operating earnings (loss), as previously reported[(1)(2)]	104	278	131	(226)	287
Adjustments for one-time earnings effects:					
Redetermination of working interests in Terra Nova	—	8	—	—	8
Modification of the bitumen valuation methodology	9	—	—	—	9
Removal of operating earnings adjustments:					
Mark-to-market valuation of stock-based compensation	2	12	8	29	51
Project start-up costs	(8)	(1)	—	—	(9)
Costs related to deferral of growth projects	(30)	—	—	—	(30)
IFRS adjustments:					
Net earnings (loss)	13	44	8	(2)	63
Operating earnings reconciling items:					
Gain on significant disposals	—	(9)	—	—	(9)
Operating earnings (loss), as restated in this MD&A	**90**	**332**	**147**	**(199)**	**370**

(1) Operating earnings (loss) includes amounts classified as discontinued operations under Previous GAAP.

(2) Operating earnings (loss) as previously reported in Suncor's MD&A dated May 3, 2010.

Year ended December 31, 2010 ($ millions)	Oil Sands	Exploration and Production	Refining and Marketing	Corporate, Energy Trading and Eliminations	Total
Operating earnings (loss), as previously reported[(1)(2)]	1 535	1 124	782	(709)	2 732
Removal of operating earnings adjustments:					
Mark-to-market valuation of stock-based compensation	(31)	(23)	(30)	(19)	(103)
Loss/(gain) on significant disposals	(4)	—	26	—	22
Project start-up costs	(55)	(3)	—	—	(58)
Costs related to deferral of growth projects	(94)	—	—	—	(94)
IFRS adjustments:					
Net earnings (loss)	28	218	18	(6)	258
Operating earnings reconciling items:					
Gain on significant disposals	—	(38)	—	—	(38)
Impairment and write-offs	—	83	—	—	83
Operating earnings (loss), as restated in this MD&A	**1 379**	**1 361**	**796**	**(734)**	**2 802**

(1) Operating earnings (loss) includes amounts classified as discontinued operations under Previous GAAP.

(2) Operating earnings (loss) as previously reported in Suncor's MD&A dated February 24, 2011.

Return on Capital Employed (ROCE)

ROCE is a non-GAAP measure that management uses to analyze operating performance, leverage and liquidity.

For the twelve months ended March 31 ($ millions, unless otherwise noted)		**2011**	2010
Adjustments to net earnings[(1)]			
Net earnings		**4 082**	2 114
Add after-tax amounts for:			
Unrealized foreign exchange gain on U.S. dollar denominated long-term debt		**(308)**	(1 173)
Interest expense		**300**	361
	A	**4 074**	1 302
Capital employed – beginning of twelve-month period[(2)]			
Net debt		**13 311**	8 638
Shareholders' equity		**32 622**	14 366
		45 933	23 004
Capital employed – end of twelve-month period			
Net debt		**7 438**	13 311
Shareholders' equity		**36 400**	32 622
		43 838	45 933
Average capital employed[(3)]	B	**45 684**	38 707
ROCE – including major projects in progress (%)	A/B	**8.9**	3.4
Average capitalized costs related to major projects in progress	C	**13 045**	11 660
ROCE – excluding major projects in progress (%)	A/(B-C)	**12.5**	4.8

(1) Earnings figures for the twelve months ended March 31, 2010 include three months reported under IFRS and nine months reported under Previous GAAP. See the Basis of Presentation section of this MD&A.

(2) Financial information as at March 31, 2009 is presented as reported under Previous GAAP. See the Basis of Presentation section of this MD&A.

(3) Average capital employed is calculated as a thirteen-month average of the capital employed balance at the beginning of the twelve-month period and the month-end capital employed balances throughout the remainder of the twelve-month period. Figures for capital employed at the beginning and end of the twelve-month period are presented to show the changes in the components of the calculation over the twelve-month period.

Cash Flow from Operations

Cash flow from operations is a non-GAAP measure that adjusts a GAAP measure – Cash flow provided by operating activities – for changes in non-cash working capital, which management uses to analyze operating performance and liquidity.

Three months ended March 31	Oil Sands		Exploration and Production		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
($ millions)	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Net earnings (loss)	**605**	89	**(186)**	528	**627**	147	**(18)**	15	**1 028**	779
Adjustments for:										
Depreciation, depletion, amortization and impairment	**311**	259	**354**	470	**102**	109	**18**	10	**785**	848
Deferred income taxes	**190**	29	**253**	97	**203**	61	**(44)**	(29)	**602**	158
Accretion of liabilities	**18**	26	**19**	21	**1**	1	**—**	—	**38**	48
Unrealized foreign exchange gain on U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**(186)**	(260)	**(186)**	(260)
Change in fair value of derivative contracts	**—**	(67)	**—**	—	**3**	—	**(58)**	(13)	**(55)**	(80)
Loss (gain) on disposal of assets	**112**	9	**146**	(280)	**(6)**	3	**(1)**	—	**251**	(268)
Share-based compensation	**48**	12	**9**	(9)	**37**	(10)	**79**	(68)	**173**	(75)
Exploration expenses	**—**	—	**2**	16	**—**	—	**—**	—	**2**	16
Other	**(147)**	(92)	**(14)**	5	**(38)**	17	**(46)**	28	**(245)**	(42)
Total cash flow from (used in) operations	**1 137**	265	**583**	848	**929**	328	**(256)**	(317)	**2 393**	1 124

ADVISORY – FORWARD-LOOKING INFORMATION

This Management's Discussion and Analysis contains certain forward-looking statements and other information 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, including: expectations and assumptions concerning the accuracy of reserves and resources estimates; commodity prices and interest and foreign exchange rates; capital efficiencies and cost-savings; applicable royalty rates and tax laws; future production rates; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour and services; and the receipt, in a timely manner, of regulatory and third-party approvals. All statements and other information that address expectations or projections about the future, and other statements and information 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 and information 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. Forward-looking statements in this Management's Discussion and Analysis include references to:

- *Plans to: (i) bring Fort Hills and Voyageur (which are anticipated to be operated by Suncor) on-stream by 2016; (ii) bring Joslyn on-stream by 2017-2018; and (iii) take advantage of opportunities to share resources and knowledge across the development of these projects.*
- *Planned maintenance events scheduled for: (i) the primary upgrading units in Upgrader 2 in the second quarter of 2011, which the company expects will reduce production volumes by approximately 215,000 bbls/d over the duration of the event (expected to be approximately six weeks); (ii) central processing facilities for both Firebag for two weeks in September, and MacKay River, for two weeks overlapping the end of the third quarter; (iii) six weeks in September and October for Syncrude;*
- *Suncor's preliminary assessment that the conservation areas currently proposed by the draft LARP do not appear to overlap Suncor's leases, and that the proposed management frameworks may require Suncor to have greater participation in the evaluation of environmental issues;*
- *Suncor's plan for Terra Nova to undergo a four-week annual maintenance outage during the third quarter of 2011 and a 15-week dockside maintenance in 2012, which is expected to allow for the resolution of the presence of H_2S in certain wells;*
- *Suncor's expectation that the fourth platform at Buzzard will be completed in the second quarter of 2012;*

- *Suncor's belief that: (i) Buzzard will complete a three-week annual maintenance program during the third quarter; and (ii) White Rose will complete a 16-day maintenance outage during July 2011;*
- *Suncor's belief that its assets in Libya could be impaired in certain circumstances;*
- *Planned maintenance events at Suncor's Edmonton refinery (six-week period);*
- *Suncor's belief that: (i) the Firebag Stage 3 expansion will be fully operational during the third quarter of 2011, achieving first oil by early July 2011 and production ramping up over approximately 24 months thereafter towards targeted capacity of 62,500 bbls/d of bitumen; and (ii) production will begin at its Firebag 4 expansion in the first quarter of 2013, which has a planned capacity of 62,500 bbls/d of bitumen;*
- *Suncor's expectations on expenditures as follows: (i) the Voyageur Upgrader to focus on the remobilization of the workforce, confirmation of current design and modification of project execution plans; (ii) the Fort Hills project to focus on design base memorandum engineering; and (iii) the Joslyn project to focus on geological, engineering, regulatory and environmental studies.*
- *Scheduled completion by the end of 2011 of Suncor's MNU project;*
- *Suncor's plan to begin drilling a production well at Terra Nova in the second quarter of 2011;*
- *Anticipated first oil by the middle of 2011 at the Hibernia Southern Extension, with further capital expenditures throughout the year directed towards development drilling and subsea infrastructure;*
- *The plans for two to three wells to be drilled at White Rose this year, with completion of one pilot well and production expected in the second half of 2011, with water injection support expected to come on-stream in early 2012;*
- *Anticipated field development decision for the Golden Eagle Area Development later in 2011;*
- *Suncor's goal of continuing to focus improvement efforts on operational integrity;*
- *Suncor's planned divestment of further non-core North American Onshore properties;*
- *The belief that the company will complete both the Kent Breeze Project and the Wintering Hills Project in 2011 and that, upon completion, Suncor's renewable energy assets will displace nearly one million tonnes of carbon dioxide annually;*
- *Suncor's management's belief that Suncor will have the capital resources to fund its planned 2011 capital spending program and to meet current and long-term working capital requirements and that if additional capital is required, adequate additional financing will be available to Suncor in the debt capital markets at commercial terms and rates;*
- *Suncor's management's belief that 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;*
- *Suncor's plan to invest excess cash in short-term investments;*
- *The objectives of Suncor's short-term investment portfolio;*
- *Suncor's plan to repay $500 million Medium Term notes due in August 2011 and keep short-term debt at March 31, 2011 levels, and other investment objectives, including the company's plan to invest cash in short-term investments; and*
- *Suncor's preliminary assessments around the federal budget released on March 22, 2011.*

Forward-looking statements and information 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 information and readers are cautioned not to place undue reliance on them.

The financial and operating performance of the company's business segments, including Oil Sands, Exploration and Production, and Refining and Marketing, may be affected by a number of factors, including, but not limited to, the following:

Factors that affect our Oil Sands segment:

- *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.*
- *Bitumen supply. The unavailability of third-party bitumen, poor ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage and in situ reservoir and equipment performance could impact 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.*
- *Our 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 strategies such 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 preventive 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 light/heavy and sweet/sour crude oil differentials.*
- *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 (including our current dispute with the Alberta Department of Energy in respect of the Bitumen Valuation Methodology Regulation). 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 lower 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.*
- *Environmental initiatives. On April 5, 2011, the Government of Alberta issued its draft Lower Athabasca Regional Plan implementing the Land-Use Framework under the Alberta Land Stewardship Act. The plan identifies new conservation areas, as well as management frameworks for air,*

surface water and groundwater quality. The proposed legislation may require Suncor to have greater participation in the evaluation of environmental issues and could result in Suncor having to relinquish certain of its leases.

Factors that affect our Exploration and Production segment:

- *Volatility in crude oil and natural gas prices.*
- *Risk associated with a depressed market for asset sales, leading to losses on disposition.*
- *The accessibility and cost of mineral rights. Market demand influences the cost and available opportunities for mineral leases and acquisitions.*
- *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.*
- *Risks and uncertainties associated with international and offshore operations normally inherent in such activities such as 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.*
- *Performance after completion of maintenance is 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.*
- *Risks and uncertainties associated with weather conditions, which may result in increased costs and/or delays in exploration, operations or abandonment activities.*
- *Suncor's foreign operations and related assets are subject to a number of political, economic and socio-economic risks. Suncor's operations in Syria may be constrained by political unrest. Suncor's operations have been suspended due to political violence in Libya.*
- *Our relationships with trade unions. In the first quarter of 2011, the company negotiated a collective agreement with union leadership at Terra Nova. The agreement has not been ratified by the union leadership.*

Factors that affect our Refining and Marketing segment:

- *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 Edmonton refinery, our Sarnia refinery, our Commerce City 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, Uncertainties and Other Factors

Additional risks, uncertainties and other factors that could influence the actual results of all of Suncor's business segments include, but are not limited to, market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates; consistently and competitively finding and developing reserves that can be brought on-stream economically; success of hedging strategies; maintaining a desirable debt to cash flow ratio; changes in the general economic, market and business conditions; our ability to finance capital investment to replace reserves or increase processing capacity in a volatile commodity pricing and credit environment; fluctuations in supply and demand for Suncor's products; commodity prices, interest rates and currency exchange; volatility in natural gas and liquids prices is not predictable and can significantly impact revenues; 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; risks and uncertainties associated with consulting with stakeholders and obtaining regulatory approval for exploration and development activities in Suncor's operating areas (these risks could increase costs and/or cause delays to or cancellation of projects); effective execution of planned turnarounds; 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 reserves, resources 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, our negotiations with the Alberta Department of Energy in respect of the Bitumen Valuation Methodology Regulation and the Government of Canada's current review of greenhouse gas emissions regulations); the ability and willingness of parties with whom we have material relationships to perform their obligations to us (including in respect of any planned divestitures); risks and uncertainties associated with the ability of closing conditions to be met with respect to the sale of any of Suncor's assets, the timing of closing and the consideration to be received with respect to the planned sale of any of Suncor's assets, including the ability of counterparties to comply with their obligations in a timely manner and the receipt of any required regulatory or other third-party approvals outside of Suncor's control; the occurrence of unexpected events such as fires, blow-outs, 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 Suncor and Petro-Canada after the merger; and incorrect assessments of the values of Petro-Canada. The foregoing important factors are not exhaustive.

Many of these risk factors and other assumptions related to Suncor's forward-looking statements and information are discussed in further detail throughout this Management's Discussion and Analysis, including under the heading Risk Factors and its 2010 AIF/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 and assumptions 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 Comprehensive Income

(unaudited)

($ millions)	Three months ended March 31 2011	2010
Revenues and Other Income		
Operating revenues, net of royalties (note 7)	**9 256**	7 130
Energy supply and trading activity income	**521**	260
Interest and other income	**68**	19
	9 845	7 409
Expenses		
Purchases of crude oil and products	**3 807**	3 429
Operating, selling and general (note 8)	**2 291**	1 851
Energy supply and trading activity expenses	**457**	278
Transportation	**162**	158
Depreciation, depletion, amortization and impairment	**785**	848
Exploration	**58**	48
Loss (gain) on disposal of assets	**251**	(268)
Project start-up costs	**37**	12
Financing expenses (income) (note 9)	**(49)**	(131)
	7 799	6 225
Earnings Before Income Taxes	**2 046**	1 184
Provisions for Income Taxes (note 13)		
Current	**416**	247
Deferred	**602**	158
	1 018	405
Net Earnings	**1 028**	779
Other Comprehensive Income (Loss)		
Foreign currency translation adjustment	**37**	(375)
Foreign currency translation adjustment relating to assets held for sale	**—**	(57)
Foreign currency translation reclassified to net earnings	**14**	1
Actuarial gain (loss) on employee retirement benefit plans, net of income taxes of $4 (2010 – $29)	**18**	(84)
Other Comprehensive Income (Loss)	**69**	(515)
Total Comprehensive Income	**1 097**	264
Net Earnings per Common Share (dollars) (note 10)		
Basic	**0.65**	0.50
Diluted	**0.65**	0.46
Cash dividends	**0.10**	0.10

See accompanying notes to the interim consolidated financial statements.

Consolidated Balance Sheets

(unaudited)

($ millions)	**March 31 2011**	December 31 2010	January 1 2010
Assets			
Current assets			
Cash and cash equivalents	**3 465**	1 077	505
Accounts receivable	**4 828**	5 253	3 936
Inventories	**3 948**	3 141	2 971
Income taxes receivable	**720**	734	587
	12 961	10 205	7 999
Assets held for sale (note 11)	**94**	762	—
Total current assets	**13 055**	10 967	7 999
Property, plant and equipment, net	**48 632**	49 958	51 556
Exploration and evaluation	**4 496**	3 961	4 342
Other assets	**273**	230	259
Goodwill and other intangible assets (note 12)	**3 144**	3 422	3 433
Deferred income taxes	**43**	69	210
Total assets	**69 643**	68 607	67 799
Liabilities and Shareholders' Equity			
Current liabilities			
Short-term debt	**752**	1 984	2 317
Current portion of long-term debt	**514**	518	25
Accounts payable and accrued liabilities	**7 775**	6 524	5 796
Current portion of provisions	**354**	527	859
Income taxes payable	**984**	929	1 274
	10 379	10 482	10 271
Liabilities associated with assets held for sale (note 11)	**35**	586	—
Total current liabilities	**10 414**	11 068	10 271
Long-term debt	**9 637**	9 829	11 679
Other long-term liabilities	**2 000**	2 103	2 050
Provisions	**2 532**	2 504	3 328
Deferred income taxes	**8 660**	7 911	7 986
Shareholders' equity	**36 400**	35 192	32 485
Total liabilities and shareholders' equity	**69 643**	68 607	67 799

See accompanying notes to the interim consolidated financial statements.

Consolidated Statements of Cash Flows

(unaudited)

($ millions)	Three months ended March 31 **2011**	2010
Operating Activities		
Net earnings	**1 028**	779
Adjustments for:		
Depreciation, depletion, amortization and impairment	**785**	848
Deferred income taxes	**602**	158
Accretion of liabilities	**38**	48
Unrealized foreign exchange gain on U.S. dollar denominated long-term debt (note 9)	**(186)**	(260)
Change in fair value of derivative contracts	**(55)**	(80)
Loss (gain) on disposal of assets	**251**	(268)
Share-based compensation	**173**	(75)
Exploration	**2**	16
Other	**(245)**	(42)
Decrease (increase) in non-cash working capital	**125**	(858)
Cash flow provided by operating activities	**2 518**	266
Investing Activities		
Capital and exploration expenditures	**(1 602)**	(1 121)
Other investments	**5**	—
Proceeds from disposal of assets	**2 690**	942
Cash flow provided by (used in) investing activities	**1 093**	(179)
Financing Activities		
Net change in short-term debt	**(1 232)**	5
Net change in long-term debt	**(4)**	146
Issuance of common shares under share option plans	**168**	15
Dividends paid on common shares	**(153)**	(153)
Cash flow provided by (used in) financing activities	**(1 221)**	13
Increase in Cash and Cash Equivalents	**2 390**	100
Effect of foreign exchange on cash and cash equivalents	**(2)**	(3)
Cash and cash equivalents at beginning of period	**1 077**	505
Cash and Cash Equivalents at End of Period	**3 465**	602
Supplementary Cash Flow Information		
Interest paid	**101**	92
Income taxes paid	**308**	231

See accompanying notes to the interim consolidated financial statements.

Consolidated Statements of Changes in Shareholders' Equity

(unaudited)

($ millions)	Share Capital	Contributed Surplus	Foreign Currency Translation	Cash Flow Hedge	Retained Earnings	Total	Number of Common Shares (thousands)
At January 1, 2010	20 053	536	—	15	11 881	32 485	1 559 778
Net earnings	—	—	—	—	779	779	—
Foreign currency translation adjustment	—	—	(431)	—	—	(431)	—
Actuarial loss on employee retirement benefit plans	—	—	—	—	(84)	(84)	—
Total comprehensive income (loss)	—	—	(431)	—	695	264	—
Dividends paid on common shares	—	—	—	—	(153)	(153)	—
Issued under share option plans	20	(5)	—	—	—	15	1 230
Issued under dividend reinvestment plan	3	—	—	—	(3)	—	96
Share-based payment expense	—	11	—	—	—	11	—
At March 31, 2010	20 076	542	(431)	15	12 420	32 622	1 561 104
At December 31, 2010	20 188	507	(451)	14	14 934	35 192	1 565 489
Net earnings	**—**	**—**	**—**	**—**	**1 028**	**1 028**	**—**
Foreign currency translation adjustment	**—**	**—**	**51**	**—**	**—**	**51**	**—**
Actuarial gain on employee retirement benefit plans	**—**	**—**	**—**	**—**	**18**	**18**	**—**
Total comprehensive income	**—**	**—**	**51**	**—**	**1 046**	**1 097**	**—**
Dividends paid on common shares	**—**	**—**	**—**	**—**	**(153)**	**(153)**	**—**
Issued under share option plans	**262**	**(41)**	**—**	**—**	**—**	**221**	**7 405**
Issued under dividend reinvestment plan	**4**	**—**	**—**	**—**	**(4)**	**—**	**99**
Share-based payment expense	**—**	**43**	**—**	**—**	**—**	**43**	**—**
At March 31, 2011	**20 454**	**509**	**(400)**	**14**	**15 823**	**36 400**	**1 572 993**

See accompanying notes to the interim consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

1. REPORTING ENTITY AND DESCRIPTION OF THE BUSINESS

Suncor Energy Inc. (Suncor or the company) is an integrated energy company headquartered in Canada. Suncor's operations include oil sands development and upgrading, onshore and offshore oil and gas production, petroleum refining and product marketing primarily under the Petro-Canada brand. The consolidated financial statements of the company comprise the company and its subsidiaries and the company's interests in associates and jointly controlled entities.

The address of the company's registered office is 150 - 6th Avenue S.W., Calgary, Alberta, Canada, T2P 3E3.

2. BASIS OF PREPARATION

(a) Statement of Compliance

These condensed consolidated interim financial statements have been prepared in accordance with Canadian generally accepted accounting principles (GAAP), specifically International Accounting Standard 34 *Interim Financial Reporting* within Part 1 of the Canadian Institute of Chartered Accountants (CICA) Handbook. They are condensed as they do not include all of the information required for full annual financial statements, and they should be read in conjunction with the consolidated financial statements of the company as at and for the year ended December 31, 2010.

These are the company's first consolidated financial statements prepared in accordance with International Financial Reporting Standards (IFRS), and IFRS 1 *First-Time Adoption of International Financial Reporting Standards* (IFRS 1) has been applied. In previous years, the company prepared its consolidated financial statements in accordance with Canadian generally accepted accounting principles in effect prior to January 1, 2011 (Previous GAAP). Comparative information has been restated from Previous GAAP to IFRS. The impact of the transition to IFRS on the company's previously reported financial statements is presented in note 5.

The policies applied in these condensed interim consolidated financial statements are based on IFRS issued and outstanding as of May 2, 2011, the date the Board of Directors approved the statements. Any subsequent changes to IFRS that are given effect in the company's annual consolidated financial statements for the year ending December 31, 2011 could result in restatement of these interim consolidated financial statements, including the adjustments recognized on transition to IFRS.

(b) Basis of Measurement

The consolidated financial statements are prepared on a historical cost basis except as detailed in the company's accounting policies disclosed in note 3. The accounting policies described in note 3 have been applied consistently to all periods presented in these financial statements except for the opening IFRS consolidated balance sheet, which has utilized certain exemptions available under IFRS 1.

(c) Functional Currency

These consolidated financial statements are presented in Canadian dollars (Cdn$), which is the company's functional currency.

(d) Use of Estimates and Judgment

The timely preparation of financial statements requires that management make estimates and assumptions and use judgment regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as at the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Significant estimates and judgment used in the preparation of the financial statements are described in note 4.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Principles of Consolidation

The company consolidates its interest in entities in which it controls. Control comprises the power to govern an entity's financial and operating policies so as to obtain benefits from its activities. Suncor recognizes its share of assets, liabilities, income and expenses, on a line-by-line basis, of its jointly controlled entities and jointly controlled assets. Investments in entities over which the company has significant influence are accounted for using the equity method. All intercompany balances and transactions have been eliminated.

(b) Foreign Currency Translation

Functional currencies of the company's individual entities represent the currency of the primary economic environment in which the entity operates. Transactions in foreign currencies are translated to the appropriate functional currency at foreign exchange rates that approximate those on the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the appropriate functional currency at foreign exchange rates at the balance sheet date. Foreign exchange differences arising on translation are recognized in earnings. Non-monetary assets that are measured in a foreign currency at historical cost are translated using the exchange rate at the date of the transaction.

In preparing the company's consolidated financial statements, the financial statements of each entity are translated into Canadian dollars. The assets and liabilities of foreign operations are translated into Canadian dollars at exchange rates at the balance sheet date. Revenues and expenses of foreign operations are translated into Canadian dollars using foreign exchange rates that approximate those on the date of the underlying transaction. Foreign exchange differences are recognized in other comprehensive income.

If an entity disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the accumulated foreign currency translation gains or losses related to the foreign operation are recognized in net earnings.

(c) Revenues

Revenue from the sale of crude oil, natural gas, natural gas liquids, purchased products and refined petroleum products is recorded when title passes to the customer and collection is reasonably assured. Revenue from properties in which the company has an interest with other producers is recognized on the basis of the company's net working interest. Crude oil and natural gas sold below or above the company's working interest share of production results in production underlifts or overlifts. Underlifts are recorded as a receivable at market value with a corresponding increase to revenues while overlifts are recorded as a payable at market value with a corresponding decrease to revenues. Revenue from oil and natural gas production is recorded net of royalty obligations.

International operations conducted pursuant to exploration and production sharing agreements (EPSAs) are reflected in the consolidated financial statements based on the company's working interest. Under the EPSAs, the company and other non-governmental partners, if any, pay all exploration costs and a pro-rata share of costs to develop and operate the concessions. Each EPSA establishes specific terms for the company to recover these costs (Cost Recovery Oil) and to share in the production profits (Profit Oil). Cost Recovery Oil is determined in accordance with a formula that is generally limited to a specified percentage of production during each fiscal year. Profit Oil is that portion of production remaining after deducting Cost Recovery Oil and is shared between the joint venture partners and the respective government. Cost Recovery Oil, Profit Oil and amounts in respect of all income taxes payable by the company under the laws of the respective country are reported as sales revenue. All other government stakes, other than income taxes, are considered to be royalty interests.

Physical and financial contracts entered into for trading purposes are considered to be derivative financial instruments, and any changes in fair value are recorded on a net basis in Energy Supply and Trading Activity Income. Settlement of physical purchase

and sales contracts entered into for the company's own usage are recorded on a gross basis in Energy Supply and Trading Activity Income and Energy Supply and Trading Activity Expense.

(d) Cash and Cash Equivalents

Cash and cash equivalents consist primarily of cash in banks, term deposits, certificates of deposit and all other highly liquid investments with a maturity of three months or less at the time of purchase.

(e) Inventories

Inventories of crude oil and refined products, other than inventories held for trading purposes, are valued at the lower of cost, using the first-in, first-out method, and net realizable value. Costs include direct and indirect expenditures incurred in bringing an item or product to its existing condition and location. Materials and supplies are valued at the lower of average cost and net realizable value.

Inventories held for trading purposes in the company's energy supply and trading operations are carried at fair value less costs to sell, and any changes in fair value are recognized within Energy Supply and Trading Activity Income.

(f) Exploration and Evaluation Assets

The costs to acquire non-producing oil and gas properties or licenses to explore, exploratory well expenditures and the costs to evaluate the commercial potential of underlying resources, including related borrowing costs, are initially capitalized as Exploration and Evaluation assets. Certain exploration costs, including geological, geophysical, seismic, and sampling on oil sands properties, are charged to Exploration expense as incurred.

Exploration and evaluation assets are subject to technical, commercial and management review to confirm the continued intent to develop and extract the underlying resources. If an area or exploration well is no longer considered commercially viable, the related capitalized costs are charged to net earnings.

When management determines with reasonable certainty that an exploration and evaluation asset will be developed, as evidenced by the classification of proved or probable reserves and the appropriate internal and external approvals, the asset is transferred to Property, Plant and Equipment.

(g) Property, Plant and Equipment

Property, plant and equipment are recorded at cost.

The costs to acquire developed or producing oil and gas properties and to develop oil and gas properties, including completing geological and geophysical surveys and drilling development wells, and the costs to construct and install dedicated infrastructure, such as wellhead equipment and supporting assets, mine development, offshore platforms and subsea structures, are capitalized as oil and gas properties within Property, Plant and Equipment.

The costs to construct, install and commission, or acquire, oil and gas production equipment, including oil sands upgraders, extraction plants, mine equipment, in situ processing facilities, power generation, utility plants, and natural gas processing plants, and all renewable energy, refining, distribution, marketing assets and related decommissioning and restoration obligations, are capitalized as Property, Plant and Equipment. Where an asset or part of an asset that was separately depreciated is replaced and it is probable that future economic benefits associated with the item will flow to the company, the expenditure is capitalized and the carrying amount of the replaced asset is derecognized.

Stripping activity required to access oil sands mining resources incurred in the initial development phase are capitalized as part of the investment in the construction cost of the mine. Stripping costs incurred in the production phase are charged to expense as they relate to production for the period.

The costs of major inspection, overhaul and turnaround activities that maintain property, plant and equipment and benefit future years of operations are capitalized. Similar recurring planned maintenance managed on shorter intervals are expensed as operating costs. Replacements outside of a major inspection, overhaul or turnaround are capitalized when it is probable that future economic benefits will flow to the company and the associated carrying amount of the replaced asset is derecognized.

Leases that transfer substantially all the benefits and risks of ownership to the company are recorded as finance lease assets within Property, Plant and Equipment. Costs for all other leases are recorded as operating expense as incurred.

Borrowing costs relating to qualifying assets are capitalized as part of Property, Plant and Equipment. Capitalization of borrowing costs ceases when the asset is in the location and condition necessary for it to be capable of operating as intended. Capitalization of borrowing costs is suspended when construction of an asset is ceased for extended periods.

(h) Depreciation, Depletion and Amortization

Exploration and evaluation assets are not subject to depreciation, depletion and amortization, with the exception of leases acquired for conventional oil and gas operations. Once transferred to Property, Plant and Equipment, these costs are depleted on a unit-of-production basis. Property acquisition costs are depleted over proved reserves, while all other exploration and evaluation costs are depleted over proved developed reserves.

Capital expenditures associated with significant development projects are not depleted until assets are substantially complete and ready for their intended use.

Costs to develop oil and gas properties, and costs of dedicated infrastructure, such as wellhead equipment, offshore platforms and subsea structures, are depleted on a unit-of-production basis over proved developed reserves. A portion of these costs may not be depleted if they relate to undeveloped reserves.

Major components of Property, Plant and Equipment are depreciated on a straight-line basis over their expected useful lives.

Natural gas processing plants and transportation assets	15 to 25 years
Oil sands upgraders, extraction plants and mine facilities	20 to 40 years
Oil sands mine equipment	5 to 15 years
Oil sands in situ processing facilities	30 years
Power generation and utility plants	40 years
Refineries, ethanol and lubricants plants	20 to 40 years
Marketing and other distribution assets	20 to 40 years

The costs of major inspection, overhaul and turnaround activities that are capitalized are depreciated on a straight-line basis over the period to the next recurrence of that set of activities, which varies from two to five years.

Depreciation, depletion and amortization rates are reviewed, at least annually, or when events or conditions occur that impact capitalized costs, reserves or estimated service lives.

(i) Goodwill and Intangible Assets

Intangible assets, other than goodwill, include acquired customer lists and brand value. Brand value and goodwill have indefinite useful lives and are not subject to amortization, while customer lists are amortized over their expected useful lives, which range from five to 10 years. Expected useful lives of intangible assets are reviewed on an annual basis.

Acquisitions are accounted for using the purchase method, whereby the purchase consideration of the business combination is allocated to the identifiable assets, liabilities and contingent liabilities on the basis of fair value as of the date of acquisition.

Goodwill is calculated as the excess of the purchase price over the fair value and is allocated to the group of cash-generating units (CGU) that is expected to benefit from the synergies of the combination.

(j) Impairment of Assets

Non-Financial Assets

Goodwill and intangible assets that have an indefinite useful life are tested annually for impairment. Indefinite and definite lived assets are tested for impairment whenever events or changes in circumstance indicate that the carrying amount may not be recoverable. Exploration and evaluation assets are tested for impairment immediately prior to costs being transferred to Property, Plant and Equipment.

For the purposes of assessing impairment, assets are grouped into CGU's, defined as the lowest levels for which there are separately identifiable cash inflows. An impairment loss is recognized in Depreciation, Depletion, Amortization and Impairment for the amount by which the carrying amount of the individual asset or CGU exceeds its recoverable amount. The recoverable amount is the higher of the fair value less costs to sell and value-in-use. In determining fair value less costs to sell, recent market transactions are taken into account, if available. In the absence of such transactions, an appropriate valuation model is used. Value-in-use is assessed using the present value of the expected future cash flows of the relevant asset or CGU. Exploration and evaluation assets are tested with the producing CGU for which the activity can be attributed or separately where a producing CGU does not exist for the exploration and evaluation activity.

Impairments are reversed for all CGUs and individual assets, other than goodwill, to the extent that events or circumstances give rise to changes in the estimate of recoverable amount since the period the impairment was recorded. Impairment reversals are recognized within Depreciation, Depletion, Amortization and Impairment.

Financial Assets

At each reporting date, the company assesses whether there is objective evidence that a financial asset is impaired. If a financial asset carried at amortized cost is impaired, the amount of the loss is measured as the difference between the amortized cost of the loan or receivable and the present value of the estimated future cash flows, discounted using the instrument's original effective interest rate. The loss is recognized in Depreciation, Depletion, Amortization and Impairment.

(k) Assets Held For Sale

Assets and liabilities are classified as held for sale if their carrying amounts are expected to be recovered through a disposition rather than through continuing use. The assets or disposal groups are measured at the lower of their carrying amount and fair value less costs to sell. Impairment losses on initial classification as held for sale and subsequent gains or losses on remeasurement are recognized in Loss (Gain) on Disposal of Assets. Assets classified as held for sale are not depreciated, depleted or amortized.

(l) Provisions

Provisions are recognized by the company when it has a legal or constructive obligation as a result of past events, it is probable that an outflow of economic resources will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation.

Provisions are recognized for decommissioning and restoration obligations associated with the company's exploration and evaluation assets and property, plant and equipment. The best estimate of the decommissioning and restoration provision is recorded on a discounted basis using the credit-adjusted risk-free interest rate. The value of the obligation is added to the carrying amount of the associated property, plant and equipment asset and amortized over the useful life of the asset. The provision is accreted over time through charges to Financing Expenses with actual expenditures charged against the accumulated obligation. Changes in the future cash flow estimates resulting from revisions to the estimated timing or amount of undiscounted cash flows are recognized as a change in the decommissioning and restoration provision and related asset.

(m) Income Taxes

The company follows the liability method of accounting for income taxes whereby deferred income taxes are recorded for the effect of differences between the accounting and income tax basis of an asset or liability. Deferred income tax assets and liabilities are measured using enacted or substantively enacted income tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are anticipated to be recovered or settled. Changes to these balances are recognized in income in the period during which they occur. Investment tax credits are recorded as an offset to the related expenditures.

(n) Pensions and Other Post-Retirement Benefits

The company sponsors defined benefit pension plans (DB Plans), defined contribution pension plans (DC Plans) and other post-retirement benefits. Company contributions to the DC Plans are expensed as incurred. The cost of the DB Plans and other post-retirement benefits received by employees is actuarially determined separately for each plan using the projected unit credit method based on present pay levels and management's best estimates of demographic and financial assumptions, and such cost is pro-rated based on service. Actuarial gains and losses are recognized in Other Comprehensive Income and transferred directly to Retained Earnings.

The defined benefit pension plan surplus or deficit in the balance sheet comprises the total for each plan of the present value of the defined benefit obligation, less the fair value of plan assets out of which the obligations are to be settled directly. When the calculation results in a benefit to the company, the recognized asset is limited to the total of unrecognized past service costs and the present value of refunds from, and reductions, in future contributions to the plan. The fair value of plan assets is determined using market values.

Past service costs are recognized on a straight-line basis over the post-retirement benefits vesting period.

(o) Share-Based Compensation Plans

Under the company's share-based compensation plans, share-based awards are granted to executives, employees and non-employee directors. Compensation expense is recorded to Operating, Selling and General expense.

For common share options, the expense is based on the fair value of the options at the time of grant and is recognized as an expense over the vesting periods of the respective options. A corresponding increase is recorded to Contributed Surplus in Shareholders' Equity. Consideration paid to the company on exercise of options is credited to Share Capital in Shareholders' Equity.

Share-based compensation awards that settle in cash or have the option to settle in cash or shares are measured at fair value each reporting period and recognized as an expense over the vesting period, with a corresponding adjustment to liabilities. When awards are surrendered for cash, the cash settlement paid reduces the outstanding liability. When awards are exercised for common shares, consideration paid by the holder and the previously recognized liability associated with the options are recorded to Share Capital in Shareholders' Equity.

(p) Financial Instruments

All financial instruments are initially recognized at fair value on the balance sheet. Subsequent measurement of financial instruments is based on their classification. Financial assets are classified as either fair value through profit and loss, loans and receivables, held-to-maturity and available for sale. Financial liabilities are classified as either fair value through profit and loss or other financial liabilities. Transaction costs are included in the initial carrying amount of financial instruments except for fair value through profit and loss items, in which case they are expensed as incurred.

Financial assets and liabilities are classified as fair value through profit and loss if they are held for trading or are designated as such upon initial recognition. This category of financial instruments includes derivative financial assets and liabilities other than those designated as effective hedging instruments. Derivative financial instruments are used by the company to manage certain

exposures to fluctuations in interest rates, commodity prices and foreign exchange rates, and for trading purposes. Changes in fair value of these financial instruments are recognized in Interest and Other Income and Energy Supply and Trading Activity Income.

Financial assets classified as loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. The held-to-maturity classification consists of non-derivative financial assets that the company has the intent and ability to hold until maturity. Financial liabilities classified as other financial liabilities consist of liabilities not classified as fair value through profit and loss. Financial instruments classified as held-to-maturity, loans and receivables and other financial liabilities are measured at amortized cost using the effective interest rate method.

Derivatives embedded in other financial instruments or other host contracts are recorded as separate derivatives when their risks and characteristics are not closely related to those of the host contract. Embedded derivatives are measured at fair value at each balance sheet date and changes in the fair value are recognized in earnings.

Physical commodity contracts considered to be derivative financial instruments are classified as fair value through profit and loss financial instruments and recognized on a net basis in Energy Supply and Trading Activity Income. Physical commodity contracts entered into for the purpose of receipt or delivery in accordance with the company's expected purchase, sale or usage requirements are not considered to be derivative financial instruments. Such contracts are recognized on a gross basis when the associated volumes are delivered in Energy Supply and Trading Activity Income and Energy Supply and Trading Activity Expenses.

(q) Hedging Activities

The company may apply hedge accounting to arrangements that qualify for hedge accounting treatment, which include fair value and cash flow hedges. Documentation is prepared at the inception of a hedge relationship in order to qualify for hedge accounting. Designated hedges are assessed at each reporting date to determine if the relationship between the derivative and the underlying hedged exposure is still effective and to quantify any ineffectiveness in the relationship.

If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk are recognized in earnings. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in Other Comprehensive Income and are recognized in earnings when the hedged item is realized. Ineffective portions of changes in the fair value of cash flow hedges are recognized in earnings immediately.

(r) Share Capital

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and share options are recognized as a deduction from equity, net of any tax effects.

(s) Dividend Distributions

Dividends on common shares are recognized in the period in which the dividends are approved by the company's Board of Directors.

(t) Earnings per Share

Basic earnings per share is calculated by dividing the Net Earnings (Loss) for the period by the weighted-average number of common shares outstanding during the period.

Diluted earnings per share is calculated by adjusting the weighted-average number of common shares outstanding for dilutive common shares related to the company's share-based compensation plans. The number of shares included is computed using the treasury stock method. For share-based compensation plans that may be settled in ordinary shares or cash at the holder's option, the more dilutive of cash settlement and share settlement is used in calculating diluted earnings per share.

4. SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGMENTS

Oil and Gas Reserves and Resources

Certain depletion, depreciation, impairment and decommissioning and restoration charges are measured based on the company's estimate of oil and gas reserves and resources. The estimation of reserves and resources is an inherently complex process and involves the exercise of professional judgment. Reserves and resources have been evaluated at December 31, 2010 by independent petroleum consultants in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. The reserves and resources estimates are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook.

Oil and gas reserves and resources estimates are based on a range of geological, technical and economic factors, including projected future rates of production, estimated commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Assumptions reflect market and regulatory conditions existing at December 31, 2010, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Exploration and Evaluation Costs

Certain exploration and evaluation costs are initially capitalized with the intent to establish commercially viable reserves. The company is required to make estimates and judgment about future events and circumstances regarding the economic viability of extracting the underlying resources. The costs are subject to technical, commercial and management review to confirm the continued intent to develop and extract the underlying resources. Unsuccessful drilling, or changes to project economics, resource quantities, expected production techniques, production costs and required capital expenditures, are important factors when making this determination. If a judgment is made that the extraction of resources is not viable, the associated exploration and evaluation costs are impaired and charged to net earnings.

Decommissioning and Restoration Costs

The company recognizes liabilities for the future decommissioning and restoration of property, plant and equipment. These provisions are based on estimated costs, which take into account the anticipated method and extent of restoration, technological advances and the possible future use of the site. Actual costs are uncertain and estimates can vary as a result of changes to relevant laws and regulations, the emergence of new technology, operating experience and prices. The expected timing of future decommissioning and restoration may change due to certain factors, including reserve life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

Deferred Income Taxes

Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the company's estimate, the ability of the company to realize the deferred tax assets could be impacted.

Deferred tax liabilities are recognized when there are taxable temporary differences that will reverse and result in a future outflow of funds to a taxation authority. The company records a provision for the amount that is expected to be settled, which requires the application of judgment as to the ultimate outcome. Deferred tax liabilities could be impacted by changes in the company's estimate of the likelihood of a future outflow, the expected settlement amount, and the tax laws in the jurisdictions in which the company operates.

Pensions and Other Post-Retirement Benefits

The company provides benefits to employees, including pensions and other post-retirement benefits. The cost of defined benefit pension plans and other post-retirement benefits received by employees is determined based on actuarial valuation methods and assumptions. Changes to assumptions related to discount rates, expected return on plan assets and annual rates of compensation increases may have a material impact on the amounts presented.

Impairment of Assets

A cash generating unit (CGU) is defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, similar exposure to market risks, shared infrastructures, and the way in which management monitors the operations.

The recoverable amounts of CGUs and individual assets have been determined based on the higher of fair value less costs to sell or value-in-use calculations. The key assumptions the company uses in estimating future cash flows for recoverable amounts are anticipated future commodity prices, expected production volumes, future operating and development costs, and refining margins. Changes to these assumptions will affect the recoverable amounts of CGUs and individual assets and may then require a material adjustment to their related carrying value.

Derivative Financial Instruments

When not directly observable in active markets, the company uses third-party models and valuation methodologies that utilize observable market data to estimate the fair value of derivative financial instruments. In addition to market information, the company incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

5. FIRST-TIME ADOPTION OF IFRS

Effective January 1, 2011, the company began reporting under IFRS, and the accounting policies disclosed in note 3 to these consolidated financial statements have been applied in preparing the financial statements for the three month periods ended March 31, 2011 and 2010, for the year ended December 31, 2010, and in the preparation of the company's opening balance sheet at January 1, 2010 (Transition Date).

In previous years, the company prepared its consolidated financial statements in accordance with Previous GAAP. Reconciliations from Previous GAAP to IFRS for comparative periods are provided on the following pages.

Reconciliation of Equity at December 31, 2010

($ millions)	Previous GAAP[1]	Presentation Changes for Discontinued Operations[2]	Other Presentation Changes[3]	IFRS Adjustments[4]	IFRS
Assets					
Current assets					
Cash and cash equivalents	1 077	—	—	—	1 077
Accounts receivable	5 253	—	—	—	5 253
Inventories	3 141	—	—	—	3 141
Income taxes receivable	734	—	—	—	734
Deferred income taxes	210	—	(210)	—	—
Assets held for sale[5]	98	658	—	6	762
Total current assets	10 513	658	(210)	6	10 967
Property, plant and equipment, net[5][6][7][8][9][10][14]	55 290	—	(3 961)	(1 371)	49 958
Exploration and evaluation	—	—	3 961	—	3 961
Other assets	451	—	(221)	—	230
Goodwill	3 201	—	(3 201)	—	—
Goodwill and other intangible assets	—	—	3 422	—	3 422
Deferred income taxes	56	—	13	—	69
Assets of discontinued operations	658	(658)	—	—	—
Total assets	70 169	—	(197)	(1 365)	68 607
Liabilities and Shareholders' Equity					
Current liabilities					
Short-term debt	2	—	1 982	—	1 984
Current portion of long-term debt	518	—	—	—	518
Accounts payable and accrued liabilities[11][12]	6 942	—	(523)	105	6 524
Current portion of provisions	—	—	523	4	527
Income taxes payable	929	—	—	—	929
Deferred income taxes	37	—	(37)	—	—
Liabilities associated with assets held for sale[5][6][14]	98	484	—	4	586
Total current liabilities	8 526	484	1 945	113	11 068
Long-term debt[7]	11 669	—	(1 982)	142	9 829
Accrued liabilities and other	4 154	—	(4 154)	—	—
Other long-term liabilities[11][12]	—	—	1 861	242	2 103
Provisions[5][6]	—	—	2 293	211	2 504
Deferred income taxes[14]	8 615	—	(160)	(544)	7 911
Liabilities of discontinued operations	484	(484)	—	—	—
Shareholders' equity[5][6][7][8][9][10][11][12][13][14]	36 721	—	—	(1 529)	35 192
Total liabilities and shareholders' equity	70 169	—	(197)	(1 365)	68 607

See footnotes starting on page 65.

Reconciliation of Equity at March 31, 2010

($ millions)	Previous GAAP[1]	Presentation Changes for Discontinued Operations[2]	Other Presentation Changes[3]	IFRS Adjustments[4]	IFRS
Assets					
Current assets					
Cash and cash equivalents	602	—	—	—	602
Accounts receivable	4 263	—	—	—	4 263
Inventories	3 019	—	—	—	3 019
Income taxes receivable	525	—	—	—	525
Deferred income taxes	362	—	(362)	—	—
Assets held for sale	289	1 739	—	—	2 028
Total current assets	9 060	1 739	(362)	—	10 437
Property, plant and equipment, net[5][7][8][9][14]	54 473	—	(3 934)	(1 566)	48 973
Exploration and evaluation	—	—	3 934	—	3 934
Other assets	470	—	(229)	—	241
Goodwill	3 201	—	(3 201)	—	—
Goodwill and other intangible assets	—	—	3 430	—	3 430
Deferred income taxes	2	—	17	—	19
Assets of discontinued operations	1 739	(1 739)	—	—	—
Total assets	68 945	—	(345)	(1 566)	67 034
Liabilities and Shareholders' Equity					
Current liabilities					
Short-term debt	2	—	2 320	—	2 322
Current portion of long-term debt	39	—	—	—	39
Accounts payable and accrued liabilities[11][12]	6 040	—	(620)	125	5 545
Current portion of provisions	—	—	620	—	620
Income taxes payable	1 151	—	—	—	1 151
Deferred income taxes	26	—	(26)	—	—
Liabilities associated with assets held for sale[5][6][14]	201	848	—	9	1 058
Total current liabilities	7 459	848	2 294	134	10 735
Long-term debt[7]	13 730	—	(2 320)	142	11 552
Accrued liabilities and other	4 480	—	(4 480)	—	—
Other long-term liabilities[11][12]	—	—	2 076	132	2 208
Provisions[5][6]	—	—	2 404	266	2 670
Deferred income taxes[14]	8 155	—	(319)	(589)	7 247
Liabilities of discontinued operations	848	(848)	—	—	—
Shareholders' equity[5][6][7][8][9][11][12][13][14]	34 273	—	—	(1 651)	32 622
Total liabilities and shareholders' equity	68 945	—	(345)	(1 566)	67 034

See footnotes starting on page 65.

Reconciliation of Equity at January 1, 2010

($ millions)	Previous GAAP[1]	Presentation Changes[3]	IFRS Adjustments[4]	IFRS
Assets				
Current assets				
Cash and cash equivalents	505	—	—	505
Accounts receivable	3 936	—	—	3 936
Inventories	2 971	—	—	2 971
Income taxes receivable	587	—	—	587
Deferred income taxes	332	(332)	—	—
Total current assets	8 331	(332)	—	7 999
Property, plant and equipment, net[5][7][8][9][14]	57 485	(4 297)	(1 632)	51 556
Exploration and evaluation	—	4 342	—	4 342
Other assets	536	(277)	—	259
Goodwill	3 201	(3 201)	—	—
Goodwill and other intangible assets	—	3 433	—	3 433
Deferred income taxes	193	17	—	210
Total assets	69 746	(315)	(1 632)	67 799
Liabilities and Shareholders' Equity				
Current liabilities				
Short-term debt	2	2 315	—	2 317
Current portion of long-term debt	25	—	—	25
Accounts payable and accrued liabilities[11][12]	6 529	(859)	126	5 796
Current portion of provisions	—	859	—	859
Income taxes payable	1 274	—	—	1 274
Deferred income taxes	18	(18)	—	—
Total current liabilities	7 848	2 297	126	10 271
Long-term debt[7]	13 855	(2 315)	139	11 679
Accrued liabilities and other	5 062	(5 062)	—	—
Other long-term liabilities[11][12]	—	2 030	20	2 050
Provisions[5]	—	3 032	296	3 328
Deferred income taxes[14]	8 870	(297)	(587)	7 986
Shareholders' equity[5][7][8][9][11][12][13][14]	34 111	—	(1 626)	32 485
Total liabilities and shareholders' equity	69 746	(315)	(1 632)	67 799

See footnotes starting on page 65.

Reconciliation of Comprehensive Income for the Year Ended December 31, 2010

($ millions)	Previous GAAP[1]	Presentation Changes for Discontinued Operations[2]	Other Presentation Changes[3]	IFRS Adjustments[4]	IFRS
Revenues and Other Income					
Operating revenues	33 278	911	(2 186)	—	32 003
Less: Royalties	(2 017)	(41)	2 058	—	—
Operating revenues, net of royalties	31 261	870	(128)	—	32 003
Energy supply and trading activity income	2 700	—	—	—	2 700
Interest and other income	389	—	110	—	499
	34 350	870	(18)	—	35 202
Expenses					
Purchases of crude oil and products	14 911	(62)	(18)	—	14 831
Operating, selling and general[7][11][12]	7 810	185	—	(11)	7 984
Energy supply and trading activity expenses	2 598	—	—	—	2 598
Transportation	656	47	—	—	703
Depreciation, depletion, amortization and impairment[5][7][8][9][10]	3 813	264	—	(274)	3 803
Accretion of asset retirement obligations	178	27	(205)	—	—
Exploration	197	21	—	—	218
Gain on disposal of assets[6]	(107)	(814)	—	(54)	(975)
Project start-up costs	77	—	—	—	77
Financing expenses (income)[5][7]	(30)	18	205	(6)	187
	30 103	(314)	(18)	(345)	29 426
Earnings Before Income Taxes	4 247	1 184	—	345	5 776
Provisions for Income Taxes					
Current	1 004	192	—	—	1 196
Deferred[14]	555	109	—	87	751
	1 559	301	—	87	1 947
Net Earnings from Continuing Operations	2 688	883	—	258	3 829
Net Earnings from Discontinued Operations	883	(883)	—	—	—
Net Earnings	3 571	—	—	258	3 829
Other Comprehensive Loss					
Foreign currency translation adjustment[5][11]	(503)	—	63	3	(437)
Foreign currency translation adjustment relating to assets held for sale[6]	—	—	(63)	—	(63)
Foreign currency translation reclassified to net earnings[6]	53	—	—	(4)	49
Gain on cash flow hedges reclassified to net earnings	(1)	—	—	—	(1)
Actuarial loss on defined benefit pension plans[11][14]	—	—	—	(152)	(152)
Other Comprehensive Loss	(451)	—	—	(153)	(604)
Total Comprehensive Income	3 120	—	—	105	3 225

See footnotes starting on page 65.

Reconciliation of Comprehensive Income for the Three Months Ended March 31, 2010

($ millions)	Previous GAAP[1]	Presentation Changes for Discontinued Operations[2]	Other Presentation Changes[3]	IFRS Adjustments[4]	IFRS
Revenues and Other Income					
Operating revenues	7 327	282	(479)	—	7 130
Less: Royalties	(459)	(13)	472	—	—
Operating revenues, net of royalties	6 868	269	(7)	—	7 130
Energy supply and trading activity income	260	—	—	—	260
Interest and other income	8	3	8	—	19
	7 136	272	1	—	7 409
Expenses					
Purchases of crude oil and products	3 428	—	1	—	3 429
Operating, selling and general[7][11][12]	1 801	56	—	(6)	1 851
Energy supply and trading activity expenses	278	—	—	—	278
Transportation	148	10	—	—	158
Depreciation, depletion, amortization and impairment[5][7][8][9]	850	62	—	(64)	848
Accretion of asset retirement obligations	46	7	(53)	—	—
Exploration	46	2	—	—	48
Gain on disposal of assets[6]	(24)	(231)	—	(13)	(268)
Project start-up costs	12	—	—	—	12
Financing expenses (income)[5][7]	(190)	8	53	(2)	(131)
	6 395	(86)	1	(85)	6 225
Earnings Before Income Taxes	741	358	—	85	1 184
Provisions for Income Taxes					
Current	168	79	—	—	247
Deferred[14]	98	38	—	22	158
	266	117	—	22	405
Net Earnings from Continuing Operations	475	241	—	63	779
Net Earnings from Discontinued Operations	241	(241)	—	—	—
Net Earnings	716	—	—	63	779
Other Comprehensive Loss					
Foreign currency translation adjustment[5][11]	(435)	—	58	2	(375)
Foreign currency translation adjustment relating to assets held for sale[6]	—	—	(58)	1	(57)
Foreign currency translation reclassified to net earnings[6]	6	—	—	(5)	1
Actuarial loss on employee retirement benefit plans[10][14]	—	—	—	(84)	(84)
Other Comprehensive Loss	(429)	—	—	(86)	(515)
Total Comprehensive Income	287	—	—	(23)	264

See footnotes starting on page 65.

Explanation of Significant Adjustments

(1) Represents amounts reported under Previous GAAP. Previous GAAP balances as at January 1, 2010 agree to December 31, 2009 balances reported in the company's 2009 Annual Report. Previous GAAP balances as at and for the three months ended March 31, 2010 have been reclassified to conform to the presentation at December 31, 2010.

(2) Certain assets held for sale reported as discontinued operations under Previous GAAP are not classified as such under IFRS.

(3) Represents other presentation changes to comply with IFRS. A description of significant reclassifications are as follows:

- Exploration and Evaluation assets reported within Property, Plant and Equipment under Previous GAAP are reflected as a separate line under IFRS.
- Short-term debt instruments supported by a revolving credit facility with a separate lender are classified as Short-Term Debt under IFRS. These short-term debt instruments were classified as Long-Term Debt under Previous GAAP.
- Liabilities encompassing significant uncertainty in timing or amount are reported as Provisions under IFRS. Under Previous GAAP, these liabilities were classified within Accounts Payable and Accrued Liabilities, and Accrued Liabilities and Other.

There were no presentation changes made to the Consolidated Statements of Cash Flows.

(4) Represents the impact on financial statements of transition to IFRS from Previous GAAP, except for presentation changes. The significant adjustments are described below, with the resulting impacts on income taxes described in paragraph (14).

(5) *Decommissioning and Restoration*

Under Previous GAAP, increases in the estimated cash flows were discounted using the current credit-adjusted risk-free rate, while downward revisions in the estimated cash flows were discounted using the credit-adjusted risk-free rate that existed when the original liability was recognized. Under IFRS, estimated cash flows are discounted using the credit-adjusted risk-free rate that exists at the balance sheet date.

In accordance with IFRS 1, the company elected to remeasure its decommissioning and restoration costs at the Transition Date and has estimated the related asset by discounting the liability to the date in which the liability arose and recalculated the accumulated depreciation, depletion and amortization under IFRS. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at and for the three months ended Mar 31, 2010	As at Jan 1, 2010
Assets held for sale	6	—	—
Property, plant and equipment, net	(688)	(681)	(690)
Liabilities associated with assets held for sale	27	14	—
Provisions	217	275	296
Foreign currency translation	1	1	—
Retained earnings	(927)	(971)	(986)
Depreciation, depletion, amortization and impairment	(40)	(10)	—
Financing expenses (income)	(19)	(5)	—
Foreign currency translation adjustment	1	1	—

(6) *Dispositions*

The net carrying values of disposed properties have been adjusted to reflect their respective IFRS adjustments, resulting in revised gains or losses upon disposal of the assets. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at and for the three months ended Mar 31, 2010	As at Jan 1, 2010
Property, plant and equipment, net	22	—	—
Liabilities associated with assets held for sale	(18)	—	—
Provisions	(10)	(9)	—
Foreign currency translation	(4)	(4)	—
Retained earnings	54	13	—
Gain on disposal of assets	(54)	(13)	—
Foreign currency translation adjustment relating to assets held for sale	—	1	—
Foreign currency translation reclassified to net earnings	(4)	(5)	—

(7) *Leases*

In accordance with IFRS 1, the company elected to evaluate whether certain arrangements contain a lease based on the facts and circumstances existing at Transition Date. Pursuant to such evaluation, the company has accounted for certain arrangements as finance leases under IFRS. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at and for the three months ended Mar 31, 2010	As at Jan 1, 2010
Plant, property and equipment, net	101	104	103
Long-term debt	142	142	139
Retained earnings	(41)	(38)	(36)
Depreciation, depletion, amortization and impairment	5	2	—
Operating, selling and general	(13)	(3)	—
Financing expenses (income)	13	3	—

(8) *Derecognition of Assets*

Under Previous GAAP, carrying amounts of property, plant and equipment assets were derecognized when no future economic benefits were expected from their use. Under IFRS, this derecognition of assets occurs at the component level. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at and for the three months ended Mar 31, 2010	As at Jan 1, 2010
Property, plant and equipment, net	(141)	(112)	(113)
Retained earnings	(141)	(112)	(113)
Depreciation, depletion, amortization and impairment	28	(1)	—

(9) *Fair Value as Deemed Cost*

The company has applied the IFRS 1 election to record certain assets of property, plant and equipment at fair value on the Transition Date. The exemption has been applied to refinery assets located in Eastern Canada and certain natural gas assets in Western Canada. When estimating fair value, market information for similar assets was used, and where market information was not available, management relied on internally generated cash flow models using discount rates specific to the asset and long-term forecasts of commodity prices and refining margins. The aggregate of these fair values was $1.370 billion, resulting in a reduction of the carrying amount of property, plant and equipment as at January 1, 2010. Under Previous GAAP, impairment losses were recorded in the third quarter of 2010 for certain of these natural gas properties. There were no impairment losses recognized during 2010 under IFRS, as these properties were adjusted to fair value at the Transition Date. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at and for the three months ended Mar 31, 2010	As at Jan 1, 2010
Property, plant and equipment, net	(527)	(851)	(906)
Retained earnings	(527)	(851)	(906)
Depreciation, depletion, amortization and impairment	(379)	(55)	—

(10) *Impairment of Assets*

Under Previous GAAP, an item of property, plant and equipment is deemed recoverable if the undiscounted future cash flows exceed the net carrying amount of the asset group. Under IFRS, recoverability of property, plant and equipment is based on the higher of fair value less costs to sell and value in use of the CGU.

Under IFRS, the company recognized impairment losses for certain CGUs within the Exploration and Production operating segment during 2010. The impaired natural gas assets are located within the Western Canadian Sedimentary Basin and were grouped into CGUs based on similar geological structure, shared infrastructure and similar exposure to market risks. Declining long-term natural gas prices have resulted in the carrying amounts for these CGUs exceeding their recoverable amounts. Recoverable amounts have been determined using the fair value less costs to sell method and based on internally generated cash flow projections. In determining fair value less costs to sell, the company considered recent transactions within the industry, long-term views of natural gas prices, externally evaluated reserve volumes, and discount rates specific to the asset. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at and for the three months ended Mar 31, 2010	As at Jan 1, 2010
Property, plant and equipment, net	(112)	—	—
Retained earnings	(112)	—	—
Depreciation, depletion, amortization and impairment	112	—	—

(11) *Employee Benefits*

Under Previous GAAP, unamortized actuarial gains and losses in respect of the company's defined benefit pension plans were recognized into earnings over the expected average remaining service life of employees. In accordance with IFRS 1, the company has elected to recognize all cumulative actuarial gains and losses directly in Retained Earnings at the Transition Date. Under IFRS, actuarial gains and losses incurred in the period are recorded in Other Comprehensive Income and then transferred directly to Retained Earnings.

Under Previous GAAP, benefits are attributed to individual accounting periods for other post-retirement benefit plans commencing on the date of hire and ending when further service by the employee will lead to no benefits under the plan. Under IFRS, the company will attribute benefits on a straight-line basis from the date when service by the employee first leads to benefits under the plan and end at the same date as under Previous GAAP. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at and for the three months ended Mar 31, 2010	As at Jan 1, 2010
Accounts payable and accrued liabilities	10	15	15
Other long-term liabilities	215	122	15
Foreign currency translation	2	1	—
Retained earnings	(227)	(138)	(30)
Operating, selling and general	(4)	(5)	—
Foreign currency translation adjustment	2	1	—
Actuarial loss on defined benefit pension plans	(201)	(113)	—

(12) *Share-Based Compensation*

Under Previous GAAP, the company recorded obligations for cash-settled share-based compensation plans using the intrinsic value method. Under IFRS, obligations for these same plans are recorded as a liability using the fair value method. For equity-settled share-based compensations plans, the company accrues the cost of employee stock options over the vesting period using the graded method of amortization rather than the straight-line method, which the company used under Previous GAAP. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at and for the three months ended Mar 31, 2010	As at Jan 1, 2010
Accounts payable and accrued liabilities	95	110	111
Other long-term liabilities	27	10	5
Contributed surplus	2	8	10
Retained earnings	(124)	(128)	(126)
Operating, selling and general	(2)	2	—

(13) *Foreign Exchange*

In accordance with IFRS 1, the company elected at the Transition Date to transfer all foreign currency translation differences in respect of foreign operations that arose prior to the Transition Date to Retained Earnings. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at and for the three months ended Mar 31, 2010	As at Jan 1, 2010
Foreign currency translation	248	248	248
Retained earnings	(248)	(248)	(248)

(14) *Income Taxes*

The company recognized deferred income taxes primarily in respect of the above changes. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at and for the three months ended Mar 31, 2010	As at Jan 1, 2010
Property, plant and equipment, net	(26)	(26)	(26)
Liabilities associated with assets held for sale	(5)	(5)	—
Deferred income taxes (liability)	(544)	(589)	(587)
Retained earnings	523	568	561
Deferred income taxes (expense)	87	22	—
Actuarial loss on defined benefit pension plans	49	29	—

(15) In addition to the IFRS 1 elections described above, the company has applied the following elections:

- Business combinations and acquisitions of interests in associates and joint ventures that occurred prior to the Transition Date were not restated in accordance with IFRS. An impairment test of associated goodwill was performed as at the Transition Date and no impairment losses were identified.
- Borrowing costs incurred prior to the Transition Date were not restated in accordance with IFRS.

6. RECENTLY ANNOUNCED ACCOUNTING PRONOUNCEMENTS

In November 2009, as part of the International Accounting Standards Board's (IASB) project to replace International Accounting Standard (IAS) 39 *Financial Instruments: Recognition and Measurement*, the IASB issued the first phase of IFRS 9 *Financial Instruments*, that introduces new requirements for the classification and measurement of financial assets. The standard was revised in October 2010 to include requirements regarding classification and measurement of financial liabilities and is applicable for annual periods starting on or after January 1, 2013. The full impact of the changes in accounting for financial instruments will not be known until the IASB's project has been completed.

7. SEGMENTED INFORMATION

The company's operating segments are determined based on differences in the nature of their operations, products and services.

In the first quarter of 2011, the company combined its International and Offshore and Natural Gas segments into one new segment, Exploration and Production. All prior periods have been reclassified to conform to these segment definitions.

Intersegment sales of crude oil and natural gas are accounted for at market values and included, for segmented reporting, in revenues of the segment making the transfer and expenses of the segment receiving the transfer. Intersegment amounts are eliminated on consolidation.

									Three months ended March 31	
	Oil Sands		Exploration and Production		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
($ millions)	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Revenues and Other Income										
Operating revenues (including royalties)	**2 159**	1 168	**1 606**	1 618	**6 037**	4 732	**9**	84	**9 811**	7 602
Intersegment revenue	**1 040**	627	**209**	213	**42**	86	**(1 291)**	(926)	**—**	—
Less: Royalties	**(123)**	(70)	**(432)**	(402)	**—**	—	**—**	—	**(555)**	(472)
Operating revenues (net of royalties)	**3 076**	1 725	**1 383**	1 429	**6 079**	4 818	**(1 282)**	(842)	**9 256**	7 130
Energy supply and trading activity income	**—**	—	**—**	—	**—**	—	**521**	260	**521**	260
Interest and other income	**1**	175	**3**	2	**37**	(8)	**27**	(150)	**68**	19
	3 077	1 900	**1 386**	1 431	**6 116**	4 810	**(734)**	(732)	**9 845**	7 409
Expenses										
Purchases of crude oil and products	**364**	245	**120**	54	**4 535**	3 936	**(1 212)**	(806)	**3 807**	3 429
Operating, selling and general	**1 320**	1 162	**236**	191	**575**	505	**160**	(7)	**2 291**	1 851
Energy supply and trading activity expenses	**—**	—	**—**	—	**—**	—	**457**	278	**457**	278
Transportation	**80**	63	**32**	56	**59**	45	**(9)**	(6)	**162**	158
Depreciation, depletion, amortization and impairment	**311**	259	**354**	470	**102**	109	**18**	10	**785**	848
Exploration	**40**	5	**18**	43	**—**	—	**—**	—	**58**	48
Loss (gain) on disposal of assets	**112**	9	**146**	(280)	**(6)**	3	**(1)**	—	**251**	(268)
Project start-up costs	**37**	10	**—**	2	**—**	—	**—**	—	**37**	12
Financing expenses (income)	**18**	26	**25**	23	**6**	5	**(98)**	(185)	**(49)**	(131)
	2 282	1 779	**931**	559	**5 271**	4 603	**(685)**	(716)	**7 799**	6 225
Earnings (Loss) Before Income Taxes	**795**	121	**455**	872	**845**	207	**(49)**	(16)	**2 046**	1 184
Income taxes	**190**	32	**641**	344	**218**	60	**(31)**	(31)	**1 018**	405
Net earnings (loss)	**605**	89	**(186)**	528	**627**	147	**(18)**	15	**1 028**	779

Total Assets ($ millions)	**Mar 31 2011**	Dec 31 2010	Jan 1 2010
Oil Sands	**38 723**	39 382	36 657
Exploration and Production	**14 495**	15 899	19 218
Refining and Marketing	**12 400**	11 292	9 748
Corporate, Energy Trading and Eliminations	**4 025**	2 034	2 176
Total	**69 643**	68 607	67 799

8. SHARE-BASED COMPENSATION

The following table summarizes the share-based compensation expense (recovery) recorded for all plans within Operating, Selling and General expense in the Consolidated Statements of Comprehensive Income.

	Three months ended March 31	
($ millions)	**2011**	2010
Share-based compensation expense for equity-settled plans	**42**	12
Share-based compensation expense (recovery) for cash-settled plans	**228**	(50)
Total share-based compensation expense (recovery)	**270**	(38)

9. FINANCING EXPENSES (INCOME)

	Three months ended March 31	
($ millions)	**2011**	2010
Interest on debt	**161**	187
Capitalized interest	**(100)**	(76)
Interest expense	**61**	111
Accretion of liabilities	**38**	48
Foreign exchange gain on U.S. dollar denominated long-term debt	**(186)**	(260)
Other foreign exchange loss (gain)	**38**	(30)
Total financing expenses (income)	**(49)**	(131)

10. EARNINGS PER COMMON SHARE

	Three months ended March 31	
($ millions)	**2011**	2010
Net earnings	**1 028**	779
(millions of common shares)		
Weighted-average number of common shares	**1 570**	1 561
Dilutive securities:		
Effect of share options	**11**	15
Weighted-average number of diluted common shares	**1 581**	1 576
(dollars per common share)		
Basic earnings per share	**0.65**	0.50
Diluted earnings per share	**0.65**	0.46

Options with tandem stock appreciation rights or cash payment alternatives are accounted for as cash-settled plans. As these awards can be exchanged for common shares of the company, they are considered potentially dilutive and are included in the calculation of the company's diluted net earnings per share calculation if they have a dilutive impact in the period.

Accounting for these awards as cash-settled was determined to have the most dilutive impact for the three months ended March 31, 2011, and thus no adjustment to net earnings was required. For the three months ended March 31, 2010, accounting for these awards as equity-settled was more dilutive. As a result, a $47 million reduction to net earnings was made in the diluted earnings per share calculation for that period to account for these awards as if they were equity-settled plans.

11. ASSETS HELD FOR SALE

During 2011 and 2010, the company divested certain non-core assets as part of its continuing strategic alignment.

In the first quarter of 2011, the company completed the sale of certain non-core U.K. offshore assets for net proceeds of £105 million (Cdn$164 million).

At March 31, 2011, the company classified certain non-core natural gas properties located in Western Canada as assets held for sale.

The assets and liabilities classified as held for sale are as follows:

($ millions)	**March 31 2011**	December 31 2010	January 1 2010
Assets			
Current assets	**6**	98	—
Property, plant and equipment, net	**87**	635	—
Exploration and evaluation	**1**	29	—
Total assets	**94**	762	—
Liabilities			
Current liabilities	**4**	98	—
Provisions	**31**	311	—
Deferred income taxes	**—**	177	—
Total liabilities	**35**	586	—

In the first quarter of 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 (Cdn$502 million).

In the second quarter of 2010, the company completed the sale of non-core natural gas properties located in northeast British Columbia (Blueberry and Jedney) for net proceeds of $383 million, and non-core assets in central Alberta (Rosevear and Pine Creek) for net proceeds of $229 million.

In the third quarter of 2010, the company completed the sales of assets in Trinidad and Tobago for net proceeds of US$378 million (Cdn$383 million), and the sale of its shares in Petro-Canada Netherlands BV for net proceeds of €316 million (Cdn$420 million). The company also completed the sale of non-core natural gas properties located in west central Alberta (Bearberry and Ricinus) for net proceeds of $275 million, and non-core assets in southern Alberta (Wildcat Hills) for net proceeds of $351 million.

In the fourth quarter of 2010, the company completed the sale of certain non-core U.K. offshore assets for net proceeds of £55 million (Cdn$86 million).

12. GOODWILL AND OTHER INTANGIBLE ASSETS

	Oil Sands	Refining and Marketing			
($ millions)	Goodwill	Goodwill	Brand name	Customer lists	Total
At January 1, 2010	3 019	182	166	66	3 433
Amortization	—	—	—	(11)	(11)
At December 31, 2010	3 019	182	166	55	3 422
Derecognition of goodwill (note 14)	**(267)**	**(8)**	**—**	**—**	**(275)**
Amortization	**—**	**—**	**—**	**(3)**	**(3)**
At March 31, 2011	**2 752**	**174**	**166**	**52**	**3 144**

Goodwill acquired through business combinations has been allocated to groups of CGUs within Oil Sands and Refining and Marketing. Indefinite-lived intangible assets acquired through business combinations have been allocated to groups of CGUs within Refining and Marketing. Key assumptions and methodology used to determine recoverable amounts for groups of CGUs with significant amounts of goodwill or intangible assets are discussed below.

The company performed its last annual test for impairment as of July 31, 2010. Recoverable amounts for the Oil Sands CGUs were based on fair value less costs to sell calculated using the present value of the CGUs' expected future cash flows. The primary sources of cash flow information are derived from business plans approved by executives of the company, which were developed based on macroeconomic factors such as forward price curves for benchmark commodities, inflation rates and industry supply-demand fundamentals. When required, the projected cash flows in the business plan have been updated to reflect current market assessments of key assumptions including long-term forecasts of commodity prices, inflation rates, foreign exchange rates and discount rates specific to the asset.

Cash flow forecasts are also based on past experience, historical trends and third-party evaluations of the company's reserves and resources to determine production profiles and volumes, operating costs, maintenance and capital expenditures. Production profiles and reserve volumes are consistent with the estimates approved through the company's annual reserve evaluation process and determine the term of the underlying cash flows used in the discounted cash flow test. The associated operating and capital costs to produce these reserves are based on past experience and specific characteristics of the reservoir.

Future cash flow estimates are adjusted to reflect risks specific to the asset and discounted using after-tax discount rates. The discount rate is calculated based on the weighted-average cost of capital that is implicit in current market transactions for similar assets. The after-tax discount rate applied to cash flow projections was 11% at July 31, 2010 (January 1, 2010 – 11%) with a conservative growth rate equal to the current inflation rate of 2% (January 1, 2010 – 2%). As a result of this analysis, management did not identify impairment within the Oil Sands operating segment and the associated allocated goodwill.

13. INCOME TAXES

	Three months ended March 31	
($ millions)	**2011**	2010
Provision for (recovery of) income taxes:		
Current:		
Canada	**19**	3
Foreign	**397**	244
Deferred:		
Canada	**356**	171
Foreign	**246**	(13)
Total provision for income taxes	**1 018**	405

In March 2011, the U.K. government substantively enacted a 12% increase in the supplementary charge on U.K. oil and gas profits. Accordingly, the company recognized an increase in deferred tax expense of $442 million related to the revaluation of deferred income tax balances.

14. JOINT VENTURE WITH TOTAL

On March 22, 2011, Suncor closed the previously announced transaction to enter into a joint venture with Total E&P Company Ltd. (Total). The two companies plan to develop the Fort Hills and Joslyn oil sands mining projects together with the other project partners, and restart the construction of the Voyageur upgrader.

As a result of this transaction, Suncor acquired a 36.75% interest in Joslyn for consideration of $842 million after closing adjustments. Total acquired a 49% interest in Voyageur, a 19.2% increase in its interest in Fort Hills (reducing Suncor's interest from 60% to 40.8%), and rights to proprietary mining technology, for cash consideration of $2.662 billion after closing adjustments.

Overall, Suncor recognized a loss of $112 million related to the disposition of its interests in Voyageur and Fort Hills and the technology sale. The loss included the derecognition of $267 million of goodwill associated with the disposed interests in Fort Hills and Voyageur.

15. LIBYA

In March 2011, the company shut-in its Libyan production and ceased operations there as a result of the political violence.

At March 31, 2011, the company had not recorded any impairment adjustments related to these assets. The company is continuing to assess and evaluate its assets in Libya for potential impairment.

The carrying value of the company's net assets in Libya at March 31, 2011 was approximately $900 million.

Quarterly Operating Summary

(unaudited)

Oil Sands	Three months ended					Twelve months ended
	Mar 31 2011	Dec 31 2010	Sept 30 2010	June 30 2010	Mar 31 2010	Dec 31 2010
Production (mbbls/d)						
Total production (excluding Syncrude)	**322.1**	325.9	306.6	295.5	202.3	283.0
Firebag (mbbls/d of bitumen)	**55.2**	52.9	50.4	55.7	55.7	53.6
MacKay River (mbbls/d of bitumen)	**32.1**	32.9	28.8	32.5	31.8	31.5
Syncrude	**38.5**	37.9	31.7	38.9	32.3	35.2
Sales (mbbls/d) (excluding Syncrude)						
Light sweet crude oil	**101.0**	84.5	84.5	99.0	61.0	82.3
Diesel	**18.5**	12.2	25.8	30.7	12.9	20.4
Light sour crude oil	**183.0**	189.8	165.8	143.1	80.5	145.2
Bitumen	**23.7**	24.9	21.2	37.4	42.3	31.4
Total sales	**326.2**	311.4	297.3	310.2	196.7	279.3
Average sales price[1] (dollars per barrel) (excluding Syncrude)						
Light sweet crude oil*	**90.47**	83.02	75.49	77.55	80.84	79.03
Other (diesel, light sour crude oil and bitumen)*	**79.05**	70.29	66.39	68.53	69.53	68.63
Total*	**82.59**	73.75	68.97	71.41	73.03	71.69
Total	**82.59**	70.95	67.53	69.79	70.21	69.58
Syncrude average sales price[1] (dollars per barrel)	**93.33**	84.40	78.83	77.32	83.21	80.93
Operating costs – Total operations (excluding Syncrude) (dollars per barrel)						
Cash costs	**33.00**	34.35	32.15	31.45	46.15	35.05
Natural gas	**3.15**	2.30	1.10	3.55	5.40	2.85
Imported bitumen	**—**	0.05	0.05	0.70	2.95	0.75
Cash operating costs[2]	**36.15**	36.70	33.30	35.70	54.50	38.65
Project start-up costs	**1.30**	0.95	0.70	0.55	0.55	0.70
Total cash operating costs[3]	**37.45**	37.65	34.00	36.25	55.05	39.35
Depreciation, depletion and amortization	**8.30**	9.15	8.90	15.15	12.10	11.15
Total operating costs[4]	**45.75**	46.80	42.90	51.40	67.15	50.50
Operating costs – Syncrude** (dollars per barrel)						
Cash costs	**35.30**	32.85	39.20	28.75	39.60	34.70
Natural gas	**3.40**	3.05	2.75	2.85	4.50	3.25
Cash operating costs[2]	**38.70**	35.90	41.95	31.60	44.10	37.95
Project start-up costs	**—**	—	—	—	—	—
Total cash operating costs[3]	**38.70**	35.90	41.95	31.60	44.10	37.95
Depreciation, depletion and amortization	**20.25**	12.55	14.85	11.35	13.70	13.00
Total operating costs[4]	**58.95**	48.45	56.80	42.95	57.80	50.95
Operating costs – In situ bitumen production only (dollars per barrel)						
Cash costs	**16.60**	16.50	17.15	13.65	12.30	14.85
Natural gas	**5.40**	4.80	5.25	5.05	7.05	5.55
Cash operating costs[5]	**22.00**	21.30	22.40	18.70	19.35	20.40
Project start-up costs	**4.20**	3.35	2.50	1.45	0.95	2.05
Total cash operating costs[6]	**26.20**	24.65	24.90	20.15	20.30	22.45
Depreciation, depletion and amortization	**5.65**	5.55	5.90	4.70	5.05	5.30
Total operating costs[7]	**31.85**	30.20	30.80	24.85	25.35	27.75

Footnotes and definitions, see page 79.

Quarterly Operating Summary (continued)

(unaudited)

Exploration and Production	Three months ended					Twelve months ended
	Mar 31 2011	Dec 31 2010	Sept 30 2010	June 30 2010	Mar 31 2010	Dec 31 2010
Total Production (mboe/d)	**240.7**	261.8	297.2	299.5	330.0	296.9
North American Onshore						
Production						
Natural gas (mmcf/d)	**379**	407	500	536	649	522
Natural gas liquids and crude oil (mbbls/d)	**5.4**	5.1	7.6	8.3	14.0	8.8
Total production (mmcfe/d)	**411**	438	546	586	733	575
Average sales price (1)						
Natural gas (dollars per mcf)	**3.72**	3.38	3.71	3.46	5.32	4.04
Natural gas liquids and crude oil (dollars per barrel)	**77.85**	71.02	60.16	72.73	66.07	67.06
East Coast Canada						
Production (mbbls/d)						
Terra Nova	**16.9**	19.0	17.2	27.2	29.6	23.2
Hibernia	**29.2**	30.9	32.3	30.1	30.2	30.9
White Rose	**18.9**	13.0	16.8	13.3	14.8	14.5
	65.0	62.9	66.3	70.6	74.6	68.6
Average sales price (1) (dollars per barrel)	**104.01**	87.12	78.78	76.88	78.69	80.20
International						
Production (mboe/d)						
North Sea						
Buzzard	**50.3**	55.6	58.6	49.3	58.6	55.5
Other North Sea	**15.4**	18.7	25.2	22.7	27.5	23.5
Other International						
Libya	**24.1**	34.7	35.4	35.4	35.4	35.2
Syria	**17.4**	16.9	16.5	12.8	—	11.6
Trinidad and Tobago	**—**	—	4.2	11.1	11.7	6.7
	107.2	125.9	139.9	131.3	133.2	132.5
Average sales price (1) (dollars per boe)						
Buzzard	**94.12**	85.46	75.60	78.57	72.36	77.91
Other North Sea	**111.88**	82.77	79.40	72.01	76.10	78.16
Other International	**91.92**	83.06	70.22	64.98	59.81	70.39

Footnotes and definitions, see page 79.

Quarterly Operating Summary (continued)

(unaudited)

Refining and Marketing	Three months ended					Twelve months ended
	Mar 31 2011	Dec 31 2010	Sept 30 2010	June 30 2010	Mar 31 2010	Dec 31 2010
Eastern North America						
Refined product sales (thousands of m^3/d)						
Transportation fuels						
Gasoline	**21.1**	22.9	22.5	22.5	21.0	22.2
Distillate	**13.4**	13.7	11.7	12.5	12.3	12.4
Total transportation fuel sales	**34.5**	36.6	34.2	35.0	33.3	34.6
Petrochemicals	**2.3**	2.4	2.5	2.8	2.2	2.5
Asphalt	**1.7**	2.4	3.7	3.0	1.8	2.7
Other	**6.1**	5.3	6.0	6.0	4.3	5.5
Total refined product sales	**44.6**	46.7	46.4	46.8	41.6	45.3
Crude oil supply and refining						
Processed at refineries (thousands of m^3/d)	**33.1**	29.7	30.7	30.6	31.0	30.5
Utilization of refining capacity (%)	**97**	87	90	90	91	89
Western North America						
Refined product sales (thousands of m^3/d)						
Transportation fuels						
Gasoline	**17.0**	18.3	19.9	19.2	18.1	18.9
Distillate	**20.8**	23.2	17.4	16.3	16.9	18.5
Total transportation fuel sales	**37.8**	41.5	37.3	35.5	35.0	37.4
Asphalt	**0.5**	0.9	1.5	1.5	1.2	1.3
Other	**2.0**	2.0	3.7	5.2	4.4	3.8
Total refined product sales	**40.3**	44.4	42.5	42.2	40.6	42.5
Crude oil supply and refining						
Processed at refineries (thousands of m^3/d)	**35.3**	36.5	36.6	31.7	33.5	34.6
Utilization of refining capacity (%)	**97**	101	101	87	92	95

Footnotes and definitions, see page 79.

Quarterly Operating Summary (continued)

(unaudited)

Netbacks	Three months ended					Twelve months ended
	Mar 31 2011	Dec 31 2010	Sept 30 2010	June 30 2010	Mar 31 2010	Dec 31 2010
North American Onshore (dollars per mcfe)						
Average price realized [8]	**4.72**	4.47	4.63	4.94	6.29	5.21
Royalties	**(0.44)**	(0.44)	(0.54)	(0.12)	(1.02)	(0.56)
Transportation costs	**(0.20)**	(0.32)	(1.04)	(0.55)	(0.34)	(0.56)
Operating costs	**(1.49)**	(1.72)	(1.44)	(1.45)	(1.32)	(1.47)
Operating netback	**2.59**	1.99	1.61	2.82	3.61	2.62
East Coast Canada (dollars per barrel)						
Average price realized [8]	**105.84**	89.35	81.06	78.99	80.79	82.38
Royalties	**(32.04)**	(29.17)	(25.49)	(28.45)	(28.78)	(27.99)
Transportation costs	**(1.83)**	(2.23)	(2.28)	(2.11)	(2.10)	(2.18)
Operating costs	**(8.14)**	(7.57)	(6.80)	(6.08)	(6.38)	(6.68)
Operating netback	**63.83**	50.38	46.49	42.35	43.53	45.53
North Sea – Buzzard (dollars per barrel)						
Average price realized [8]	**96.09**	87.30	77.43	80.35	74.19	79.73
Transportation costs	**(1.97)**	(1.84)	(1.83)	(1.78)	(1.83)	(1.82)
Operating costs	**(3.50)**	(2.80)	(2.90)	(3.57)	(3.09)	(3.07)
Operating netback	**90.62**	82.66	72.70	75.00	69.27	74.84
Other North Sea (dollars per boe)						
Average price realized [8]	**114.25**	85.73	81.13	75.47	79.10	80.86
Transportation costs	**(2.37)**	(2.96)	(1.73)	(3.46)	(3.00)	(2.70)
Operating costs	**(19.60)**	(16.45)	(13.59)	(21.00)	(12.58)	(15.60)
Operating netback	**92.28**	66.32	65.81	51.01	63.52	62.56
Other International (dollars per boe)						
Average price realized [8]	**92.28**	82.74	70.54	65.36	60.20	70.59
Royalties	**(64.12)**	(18.37)	(30.30)	(30.06)	(32.55)	(30.67)
Transportation costs	**(0.36)**	0.32	(0.32)	(0.38)	(0.39)	(0.20)
Operating costs	**(5.21)**	(6.38)	(4.49)	(6.85)	(2.85)	(5.13)
Operating netback	**22.59**	58.31	35.43	28.07	24.41	34.59

Footnotes and definitions, see page 79.

Quarterly Operating Summary (continued)

Non-GAAP Financial Measures

Certain financial measures referred to in the Quarterly Operating Summary are not prescribed by Canadian generally accepted accounting principles (GAAP). Suncor includes cash and total operating costs per barrel and netback 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.

** 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.

Abbreviations

mbbls/d	– thousands of barrels per day
mcf	– thousands of cubic feet
mcfe	– thousands of cubic feet equivalent
mmcf/d	– millions of cubic feet per day
mmcfe/d	– millions of cubic feet equivalent per day
boe	– barrels of oil equivalent
mboe/d	– thousands of barrels of oil equivalent per day
m^3/d	– cubic metres per day

Metric conversion

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

P.O. Box 2844, 150 - 6th Avenue S.W., Calgary, Alberta, Canada T2P 3E3
tel: (403) 296-8000 fax: (403) 296-3030 info@suncor.com www.suncor.com