Development drilling on the first phase of the West White Rose development began in August 2010, with first oil expected by the second quarter of 2011. Drilling results from Stage 1, combined with production evaluation and ongoing reservoir evaluation, are expected to define the full field development scope.

Capital spending continues on the Hibernia South Extension project, where first production is expected in the second quarter of 2011.

The contract for front end engineering and design and topsides engineering, procurement and construction for Hebron was awarded in September 2010. The development plan approval submission is expected to be made in the first quarter of 2011, with first oil expected in 2017.

International

International and Offshore capital and exploration expenditures in the fourth quarter of 2010 on International operations were $255 million, bringing annual expenditures to $832 million, of which $169 million was related to assets disposed of during the year. Spending was primarily focused on development spending in the U.K., Libya and Syria, as well as exploration drilling in Libya and Norway.

The Buzzard enhancement project started-up in mid-October 2010 with production ramp-up expected into the first quarter of 2011. The project included the installation of a fourth platform with equipment to handle high sulphur content.

The Beta Statfjord appraisal well 34/4-13S on the Beta Brent discovery in our operated licence PL375 was successfully tested. Additional appraisal well testing is required to further delineate the discovery.

Two seismic survey projects continued to acquire data in relation to the Libyan Exploration and Production Sharing Agreements (EPSA's) in 2010. Seismic data acquisition will continue into the first quarter of 2011.

Refining and Marketing

	Three months ended December 31		Twelve months ended December 31	
($ millions, unless otherwise noted)	**2010**	2009	**2010**	2009
Revenues	**5 826**	4 743	**21 062**	11 851
Refined Product Sales (thousands of cubic metres per day)				
Gasoline	**41.2**	41.4	**41.1**	27.6
Distillates	**36.9**	29.5	**30.9**	18.3
Other, including petrochemicals	**13.0**	12.0	**15.8**	9.0
Total refined product sales	**91.1**	82.9	**87.8**	54.9
Crude oil processed by Suncor (thousands of m^3/d)	**66.2**	61.7	**65.1**	63.2
Utilization of refining capacity (1)	**94%**	90%	**92%**	92%
Cash flow from operations (2)	**619**	258	**1 536**	921

Operating earnings reconciliation:

	Three months ended December 31		Twelve months ended December 31	
($ millions, unless otherwise noted)	**2010**	2009	**2010**	2009
Net earnings	**372**	151	**801**	407
Mark-to-market valuation of stock-based compensation	**27**	1	**29**	17
Costs related to deferral of growth projects	**—**	1	**—**	1
Impact of income tax rate adjustments on future income tax liabilities	**—**	(19)	**—**	(19)
Impact of recording acquired inventory at fair value	**—**	—	**—**	67
Gains on disposals	**(10)**	—	**(26)**	—
Adjustments to provisions for assets acquired through the merger	**—**	—	**(22)**	—
Operating earnings (2)	**389**	134	**782**	473

(1) Utilization of refining capacity for the twelve months ended December 31, 2009 reflects the results of operations since the merger.

(2) See the Non-GAAP Financial Measures Advisory section of this document.

Refining and Marketing had net earnings of $372 million in the fourth quarter of 2010, compared to $151 million in the fourth quarter of 2009. Net earnings in the fourth quarter of 2010 included $27 million of costs related to stock-based compensation and a $10 million gain from divestment of retail sites throughout the quarter. Net earnings in the fourth quarter of 2009 included a $19 million favorable adjustment related to a reduction of the Ontario corporate tax rate. Operating earnings for the fourth quarter of 2010 were $389 million compared to $134 million in the fourth quarter of 2009. Operating earnings improved in the fourth quarter of 2010 primarily due to stronger and more reliable operations, higher volumes and improved margins, which were partially offset by higher operating expenses.

Margins

Margins were significantly higher in the fourth quarter of 2010 compared to the fourth quarter of 2009. Increased production enabled refining and product supply activities to benefit from an improved business environment in the fourth quarter of 2010, with higher cracking margins in every major market area and stronger product demand compared to the fourth quarter of 2009. The Sarnia refinery was negatively impacted by the Enbridge crude pipeline outage which restricted deliveries of lower cost sour crudes received from Western Canada and necessitated processing of more expensive off-shore crude. The Edmonton refinery benefited from lower feedstock costs due to wider light/heavy and light/sour synthetic crude differentials.

Volumes

Total sales of refined petroleum products increased 10% due to improved reliability in operations and higher product demand in the fourth quarter of 2010 compared to the fourth quarter of 2009. Overall, refinery utilization averaged 94% in the fourth quarter of 2010, compared to 90% in the fourth quarter of 2009. This increase was due to fewer scheduled maintenance turnarounds and more reliable, uninterrupted operations. In the fourth quarter of 2010, the Sarnia refinery continued to be negatively impacted by Enbridge pipeline disruptions which limited crude availability and refinery utilization. This production shortfall was offset by increasing throughputs at the Montreal refinery to support Ontario market demands.

Marketing network sales volumes in the fourth quarter of 2010 were marginally higher than in the fourth quarter of 2009. Strong sales in both the retail and wholesale divisions were partially offset by the loss of volume associated with the divestment of merger remedy sites.

Capital

Refining and Marketing capital expenditures in the fourth quarter of 2010 were $272 million with spending primarily focused on planned turnarounds and other refinery projects.

Annual expenditures totaled $667 million and were focused on refining assets. Successful turnarounds at all of the refineries and the lubricants business were completed during the year to support continued safe and reliable operations.

Corporate, Energy Trading and Eliminations

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

Operating Earnings Reconciliation:

($ millions)	Three months ended December 31 2010	2009	Twelve months ended December 31 2010	2009
Net (loss) earnings	**51**	(86)	**(442)**	104
Unrealized foreign exchange gain on U.S. dollar denominated long-term debt	**(252)**	(157)	**(372)**	(798)
Mark-to-market valuation of stock-based compensation	**36**	1	**19**	58
Merger and integration costs	**25**	79	**86**	151
Impact of income tax rate adjustments on future income tax liabilities	**—**	2	**—**	5
Operating loss (1)	**(140)**	(161)	**(709)**	(480)

($ millions)	Three months ended December 31 2010	2009	Twelve months ended December 31 2010	2009
Operating earnings (loss) (1)				
Renewable energy	**6**	6	**33**	29
Energy trading	**28**	23	**53**	44
Corporate	**(175)**	(195)	**(808)**	(460)
Group eliminations	**1**	5	**13**	(93)
	(140)	(161)	**(709)**	(480)
Cash flow used in operations (1)	**(219)**	(302)	**(973)**	(653)

(1) See the Non-GAAP Financial Measures Advisory section of this document.

Operating loss for the Corporate, Energy Trading and Eliminations segment was $140 million in the fourth quarter of 2010, compared to an operating loss of $161 million in the fourth quarter of 2009.

Renewable energy contributed $6 million in operating earnings in the fourth quarter of 2010, which was consistent with the same period in 2009.

Energy trading operating earnings for the fourth quarter of 2010 were $28 million, compared to $23 million in 2009. In the fourth quarter of 2010, the gain was driven by buying heavy crude oil in Western Canada at wide price differentials relative to WTI, and transporting this product to more favorable markets. In the fourth quarter of 2009, results were positively impacted by realized physical gains on crude inventory positions.

Corporate experienced an operating loss of $175 million in the fourth quarter of 2010, compared to an operating loss of $195 million in the fourth quarter of 2009. The decrease in operating loss was primarily the result of lower net interest expense due to increased capitalized interest in the fourth quarter of 2010.

Group eliminations reflect the elimination of profit on crude oil sales between Oil Sands or East Coast Canada and Refining and Marketing, where profits are realized when the products are sold to third parties.

Capital

Corporate capital expenditures were $152 million in the fourth quarter of 2010, bringing annual expenditures to $360 million. Spending was focused on merger integration related activities and renewable energy.

Work is underway to integrate legacy Suncor and legacy Petro-Canada systems onto one common platform as well as to integrate processes, information and technology.

Construction continued on the Wintering Hills wind power project in the fourth quarter of 2010, which is expected to be completed by the end of 2011. At peak operation, the project is expected to generate enough electricity to power approximately 35,000 Alberta homes and displace 200,000 tonnes of CO_2 per year.

Construction also continued on the Kent Breeze wind power project in the fourth quarter of 2010, which is expected to be completed by mid-2011.

Suncor's ethanol plant, located in Sarnia, Ontario, has a current capacity of 200 million litres per year, displacing the equivalent of 300,000 tonnes of CO_2 per year. The company's plant expansion was completed in January 2011 and has doubled the capacity of the ethanol plant to 400 million litres per year.

NON-GAAP FINANCIAL MEASURES ADVISORY

Certain financial measures referred to in this report to shareholders, namely operating earnings, cash flow from operations, return on capital employed (ROCE), and oil sands cash operating costs, are not prescribed by Canadian GAAP. These non-GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. These non-GAAP financial measures are included because management uses this information to analyze operating performance, leverage and liquidity. Therefore, such measures should not be considered in isolation or as substitutes for measures of performance prepared in accordance with Canadian GAAP.

Return on Capital Employed (ROCE)

A detailed numerical reconciliation of ROCE is provided on an annual basis in the company's annual MD&A, which is to be read in conjunction with the company's annual consolidated financial statements.

Operating Earnings

Operating earnings is a non-GAAP measure that adjusts net earnings for significant items that management believes are not indicative of operating performance and reduce 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.

Cash Operating Costs Reconciliation (1)

	Three months ended December 31				Twelve months ended December 31			
	2010		2009		**2010**		2009	
	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses (2)	**1 271**		1 300		**4 545**		4 277	
(Less) Syncrude-related operating, selling and general expenses	**(109)**		(133)		**(473)**		(199)	
(Less): Other non production related costs (3)	**(62)**		(174)		**(60)**		(479)	
Cash operating costs	**1 100**	**36.70**	993	38.70	**4 012**	**38.85**	3 599	33.95

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

(2) GAAP measure.

(3) Other adjustments includes items such as safe mode costs (the cost of placing a growth project on hold or in "safe mode"), inventory changes, stock based compensation, gas swaps, accretion of asset retirement obligations and imported bitumen (excluding other reported product purchases). For the three months ended December 31, other non production related costs are lower in 2010, compared to 2009, primarily due to lower safe mode costs ($101 million). For the twelve months ended December 31, other non production related costs are lower in 2010 compared to 2009, primarily due to lower safe mode costs deduction ($254 million) and higher imported bitumen costs ($67 million).

Cash Flow from Operations

Cash flow from operations is expressed before changes in non-cash working capital.

Three months ended December 31 ($ millions)	Oil Sands		Natural Gas		International and Offshore		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
	2010	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009
Net earnings (loss) from continuing operations	**487**	236	**(65)**	(55)	**452**	230	**372**	151	**51**	(86)	**1 297**	476
Adjustments for:												
Depreciation, depletion and amortization	**297**	300	**126**	113	**302**	218	**123**	114	**26**	12	**874**	757
Future income taxes	**144**	(103)	**(22)**	(31)	**103**	34	**133**	4	**(64)**	(18)	**294**	(114)
Accretion of asset retirement obligations	**30**	29	**9**	6	**7**	7	**—**	—	**—**	—	**46**	42
Unrealized (gain) loss on translation of U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**—**	—	**(290)**	(201)	**(290)**	(201)
Change in fair value of derivative contracts	**(66)**	(28)	**—**	1	**—**	—	**—**	5	**34**	(37)	**(32)**	(59)
Loss (gain) on disposal of assets	**3**	53	**(6)**	—	**2**	—	**(11)**	1	**38**	—	**26**	54
Stock-based compensation	**12**	14	**16**	4	**18**	1	**30**	5	**38**	10	**114**	34
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Other	**(112)**	(146)	**(11)**	(8)	**(2)**	7	**(28)**	(22)	**(52)**	18	**(205)**	(151)
Exploration expenses	**—**	—	**3**	40	**3**	3	**—**	—	**—**	—	**6**	43
Total cash flow from (used in) operations from continuing operations	**795**	355	**50**	70	**885**	500	**619**	258	**(219)**	(302)	**2 130**	881
Total cash flow from (used in) operations from discontinued operations	**—**	—	**1**	90	**13**	158	**—**	—	**—**	—	**14**	248
Total cash flow from (used in) operations	**795**	355	**51**	160	**898**	658	**619**	258	**(219)**	(302)	**2 144**	1 129

Year ended December 31 ($ millions)	Oil Sands		Natural Gas		International and Offshore		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
	2010	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009
Net earnings (loss) from continuing operations	**1 492**	557	**(277)**	(185)	**1 114**	323	**801**	407	**(442)**	104	**2 688**	1 206
Adjustments for:												
Depreciation, depletion and amortization	**1 318**	922	**773**	287	**1 172**	299	**475**	317	**75**	35	**3 813**	1 860
Future income taxes	**484**	(643)	**(96)**	(47)	**108**	48	**261**	99	**(202)**	(85)	**555**	(628)
Accretion of asset retirement obligations	**120**	111	**29**	14	**27**	10	**2**	1	**—**	—	**178**	136
Unrealized (gain) loss on translation of U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**—**	—	**(426)**	(858)	**(426)**	(858)
Change in fair value of derivative contracts	**(316)**	960	**—**	—	**—**	—	**—**	(14)	**31**	34	**(285)**	980
Loss (gain) on disposal of assets	**14**	70	**(132)**	(20)	**2**	—	**(30)**	16	**39**	—	**(107)**	66
Stock-based compensation	**48**	90	**12**	19	**18**	12	**40**	35	**(4)**	106	**114**	262
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	(438)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	(438)
Other	**(391)**	(378)	**(6)**	(11)	**8**	40	**(13)**	60	**(44)**	11	**(446)**	(278)
Exploration expenses	**—**	—	**17**	120	**63**	6	**—**	—	**—**	—	**80**	126
Total cash flow from (used in) operations from continuing operations	**2 769**	1 251	**320**	177	**2 512**	738	**1 536**	921	**(973)**	(653)	**6 164**	2 434
Total cash flow from (used in) operations from discontinued operations	**—**	—	**125**	152	**367**	213	**—**	—	**—**	—	**492**	365
Total cash flow from (used in) operations	**2 769**	1 251	**445**	329	**2 879**	951	**1 536**	921	**(973)**	(653)	**6 656**	2 799

Legal Advisory – Forward-Looking Information

This Report to Shareholders 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.

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 Report to Shareholders include references to:

- *the strategic partnership with Total E&P Canada Ltd., and the expectation that the two companies will develop the Fort Hills and Joslyn oil sands mining projects and restart construction on the Voyageur upgrader with targeted operational dates ranging from 2016 to 2018;*
- *Suncor's 2011 capital spending plan, including the intention that approximately $2.8 billion will be directed towards growth project funding (including Firebag Stage 3 and 4 expansions and investment in the Fort Hills oil sands mining projects and Voyageur upgrader), primarily at the company's oil sands operations, with the remaining $3.9 billion targeted towards sustaining existing operations, including significant planned maintenance to support reliability and further deployment of new tailings reclamation technology;*
- *the intention that approximately 40% of planned sustaining capital for 2011 will be targeted to spending that is not expected to recur on an annual basis;*
- *the planned expansion for Firebag 3, with the target to begin production late in the second quarter of 2011, ramping up toward capacity of 62,500 bpd of bitumen over approximately 24 months thereafter;*
- *the schedule for Suncor's TRO_{TM} tailings reclamation project (planned complete by the end of 2012);*
- *Suncor's drilling programs located in the Ferrier area in central Alberta and Pouce Coupe in western Alberta, including the plan to have both tied-in during the first quarter of 2011;*
- *developmental drilling in the North Amethyst portion of White Rose, and the expectation that production will peak in late 2012;*
- *the expectation that first oil will occur for: (i) West White Rose in the second quarter of 2011; and (ii) Hebron in 2017;*
- *the Hibernia South Extension, and the expectation of production in the second quarter of 2011;*
- *the expectation that the Buzzard enhancement project will ramp up into the first quarter of 2011;*
- *the plans for the Wintering Hills wind power project, including targeted completion by the end of 2011 and the expectation that the project will be able to generate enough electricity to power approximately 35,000 Alberta homes and displace 200,000 tonnes of CO_2 per year; and*
- *timelines for the Kent Breeze wind power project (expected to be completed by mid-2011).*

This Report to Shareholders also contains forward-looking statements and information concerning the anticipated completion and timing of the proposed transaction with Total E&P Canada Ltd. Suncor has provided these anticipated times in reliance on certain assumptions that we believe are reasonable at this time, including assumptions as to the timing of receipt of the necessary regulatory, court and other third party approvals; and the time necessary to satisfy the conditions to the closing of the transaction. These dates may change for a number of reasons, including unforeseen delays in the ability to secure necessary regulatory or other third party approvals or the need for additional time to satisfy the conditions to the completion of the transaction. The transaction may not close as scheduled or at all. As a result of the foregoing, readers should not place undue reliance on the forward-looking statements and information contained in this Report to Shareholders concerning these times.

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, Natural Gas, International and Offshore 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 business:

- *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 preventative maintenance.*

- *Our ability to complete projects both on time and on budget. This could be impacted by competition from other projects (including other oil sands projects) for goods and services and demands on infrastructure in Fort McMurray and the surrounding area (including housing, roads and schools). We continue to address these issues through a comprehensive recruitment and retention strategy, working with the community to determine infrastructure needs, designing Oil Sands expansion to reduce unit costs, seeking strategic alliances with service providers and maintaining a strong focus on engineering, procurement and project management.*
- *Potential changes in the demand for refinery feedstock and diesel fuel. Our strategy is to reduce the impact of this issue by entering into long-term supply agreements with major customers, expanding our customer base and offering a variety of blends of refinery feedstock to meet customer specifications.*
- *Volatility in 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.*

Factors that affect our Natural Gas business:

- *Volatility in 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.*

Factors that affect our International and Offshore business:

- *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. These risks could increase costs and/or cause delays to or cancellation of projects and expansions to existing projects.*
- *Risks and uncertainties associated with weather conditions, which may result in increased costs and/or delays in 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 Libya may be constrained by production quotas.*

Factors that affect our Refining and Marketing business:

- *Production reliability risk. Our ability to reliably operate our refining and marketing facilities in order to meet production targets.*
- *Management expects that fluctuations in demand and supply for refined products, margin and price volatility, and market competition, including potential new market entrants, will continue to impact the business environment.*
- *There are certain risks associated with the execution of capital projects, including the risk of cost overruns. Numerous risks and uncertainties can affect construction schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period.*
- *Our relationship with our trade unions. Hourly employees at our London, Ontario terminal operation, our Sarnia 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 an 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 reserve, resource and future production estimates and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venture partners; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; labour and material shortages; uncertainties resulting from potential delays or changes in plans with respect to projects or capital expenditures; actions by governmental authorities including the imposition of taxes or changes to fees and royalties, changes in environmental and other regulations (for example, the Government of Alberta's review of the unintended consequences of the proposed Crown royalty regime, our negotiations with the Alberta Department of Energy in respect of the Bitumen Valuation Methodology Regulation; the Government of Canada's current review of greenhouse gas emission regulations); the ability and willingness of parties with whom we have material relationships to perform their obligations to us (including in respect of any planned divestitures); risks and uncertainties associated with the ability of closing conditions to be met, 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, blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor; failure to realize anticipated synergies or cost savings; risks regarding the integration of the 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 Report to Shareholders and its Annual Information Form/Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission (SEC) at www.sec.gov. Readers are also referred to the risk factors 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.

Highlights

(unaudited)

	2010	2009
Cash Flow From Operations		
(dollars per common share – basic)		
For the three months ended December 31		
Cash flow from operations (1)	**1.37**	0.72
For the twelve months ended December 31		
Cash flow from operations (1)	**4.26**	2.34
Ratios		
For the twelve months ended December 31		
Return on capital employed (%) (2)	**10.1**	2.6
Return on capital employed (%) (3)	**7.4**	1.8
Net debt to cash flow from operations (times) (4)	**1.7**	4.8
Interest coverage on long-term debt (times)		
Net earnings (5)	**8.4**	3.0
Cash flow from operations (6)	**11.9**	7.2
As at December 31		
Total debt to total debt plus shareholders' equity (%) (7)	**25**	29
Common Share Information		
As at December 31		
Share price at end of trading		
Toronto Stock Exchange – Cdn$	**38.28**	37.21
New York Stock Exchange – US$	**38.29**	35.31
Common share options outstanding (thousands)	**67 638**	72 024
For the twelve months ended December 31		
Average number outstanding, weighted monthly (thousands)	**1 562 285**	1 197 710

Refer to the Quarterly Operating Summary for a discussion of financial measures not prepared in accordance with Canadian generally accepted accounting principles (GAAP).

(1) Cash flow from operations for the period; divided by the weighted-average number of common shares outstanding during the period.

(2) Net earnings (2010 – $3,491 million; 2009 – $637 million) after adjusting for after-tax financing income (2010 – $80 million; 2009 – $509 million) divided by average capital employed (2010 – $34,510 million; 2009 – $24,473 million). Average capital employed is shareholders' equity and short-term debt plus long-term debt less cash and cash equivalents, less capitalized costs related to major projects in progress, on a weighted-average basis.

(3) Average capital employed including capitalized costs related to major projects in progress (2010 – $47,399 million; 2009 – $35,128 million).

(4) Short-term debt plus long-term debt less cash and cash equivalents, divided by cash flow from operations for the twelve-month period then ended.

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

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

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

Quarterly Operating Summary

(unaudited)

	Three months ended					Twelve months ended	
	Dec 31 2010	Sept 30 2010	June 30 2010	Mar 31 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
OIL SANDS							
Production (kbpd)							
Total production (excluding Syncrude)	**325.9**	306.6	295.5	202.3	278.9	**283.0**	290.6
Firebag (kbpd of bitumen)	**52.9**	50.4	55.7	55.7	51.1	**53.6**	49.1
MacKay River (kbpd of bitumen)	**32.9**	28.8	32.5	31.8	31.7	**31.5**	29.7**
Syncrude	**37.9**	31.7	38.9	32.3	39.3	**35.2**	38.5**
Sales (kbpd) (excluding Syncrude)							
Light sweet crude oil	**84.5**	84.5	99.0	61.0	100.8	**82.3**	99.6
Diesel	**12.2**	25.8	30.7	12.9	31.4	**20.4**	29.1
Light sour crude oil	**189.8**	165.8	143.1	80.5	142.4	**145.2**	135.7
Bitumen	**24.9**	21.2	37.4	42.3	13.0	**31.4**	11.8
Total sales	**311.4**	297.3	310.2	196.7	287.6	**279.3**	276.2
Average sales price (1) (dollars per barrel) (excluding Syncrude)							
Light sweet crude oil*	**83.02**	75.49	77.55	80.84	77.71	**79.03**	67.26
Other (diesel, light sour crude oil and bitumen)*	**70.29**	66.39	68.53	69.53	72.93	**68.63**	64.18
Total*	**73.75**	68.97	71.41	73.03	74.61	**71.69**	65.29
Total	**70.95**	67.53	69.79	70.21	65.42	**69.58**	61.66
Syncrude average sales price (1) (dollars per barrel)	**84.40**	78.83	77.32	83.21	78.81	**80.93**	77.36
Operating costs – Total operations (excluding Syncrude) (dollars per barrel)							
Cash costs	**34.35**	32.45	31.70	46.50	35.10	**35.30**	31.50
Natural gas	**2.30**	1.10	3.55	5.40	3.40	**2.85**	2.40
Imported bitumen	**0.05**	0.05	0.65	2.95	0.20	**0.70**	0.05
Cash operating costs (2)	**36.70**	33.60	35.90	54.85	38.70	**38.85**	33.95
Project start-up costs	**0.95**	0.75	0.55	0.55	0.50	**0.70**	0.45
Total cash operating costs (3)	**37.65**	34.35	36.45	55.40	39.20	**39.55**	34.40
Depreciation, depletion and amortization	**8.80**	9.00	15.35	12.65	10.00	**11.25**	8.00
Total operating costs (4)	**46.45**	43.35	51.80	68.05	49.20	**50.80**	42.40
Operating costs – Syncrude*** (dollars per barrel)							
Cash costs	**32.85**	39.20	28.75	39.60	29.65	**34.70**	29.60
Natural gas	**3.05**	2.75	2.85	4.50	3.45	**3.25**	2.90
Cash operating costs (2)	**35.90**	41.95	31.60	44.10	33.10	**37.95**	32.50
Project start-up costs	**—**	—	—	—	—	**—**	—
Total cash operating costs (3)	**35.90**	41.95	31.60	44.10	33.10	**37.95**	32.50
Depreciation, depletion and amortization	**9.65**	14.85	11.35	13.70	11.80	**12.20**	12.15
Total operating costs (4)	**45.55**	56.80	42.95	57.80	44.90	**50.15**	44.65
Operating costs – In situ bitumen production only (dollars per barrel)							
Cash costs	**16.50**	17.15	13.65	12.30	14.25	**14.85**	14.55
Natural gas	**4.80**	5.25	5.05	7.05	6.05	**5.55**	5.70
Cash operating costs (5)	**21.30**	22.40	18.70	19.35	20.30	**20.40**	20.25
Project start-up costs	**3.35**	2.50	1.45	0.95	1.35	**2.05**	1.35
Total cash operating costs (6)	**24.65**	24.90	20.15	20.30	21.65	**22.45**	21.60
Depreciation, depletion and amortization	**5.20**	5.90	4.70	5.05	6.65	**5.20**	6.35
Total operating costs (7)	**29.85**	30.80	24.85	25.35	28.30	**27.65**	27.95

Footnotes, definitions and abbreviations, see page 26.

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Twelve months ended	
	Dec 31 2010	Sept 30 2010	June 30 2010	Mar 31 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
NATURAL GAS							
Gross production							
Natural gas (mmcf/d)							
Continuing operations	**399**	380	398	419	424	**399**	262
Discontinued operations	**8**	120	138	230	250	**123**	135
Natural gas liquids and crude oil (kbpd)							
Continuing operations	**4.9**	5.4	5.5	6.2	6.2	**5.5**	3.3
Discontinued operations	**0.2**	2.2	2.8	7.8	8.8	**3.3**	4.8
Total gross production (mmcfe/d)							
Continuing operations	**429**	412	431	456	461	**432**	282
Discontinued operations	**9**	134	155	277	303	**143**	164
Average sales price from continuing operations (1)							
Natural gas (dollars per mcf)	**3.39**	3.66	3.42	5.34	3.92	**3.99**	3.63
Natural gas (dollars per mcf)*	**3.39**	3.66	3.42	5.34	3.91	**3.99**	3.62
Natural gas liquids and crude oil (dollars per barrel)	**71.56**	68.03	82.82	74.71	65.74	**77.37**	59.41

Footnotes, definitions and abbreviations, see page 26.

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Twelve months ended	
	Dec 31 2010	Sept 30 2010	June 30 2010	Mar 31 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009**
INTERNATIONAL AND OFFSHORE							
East Coast Canada							
Production (kbpd)							
Terra Nova	**19.0**	17.2	27.2	29.6	24.0	**23.2**	20.8
Hibernia	**30.9**	32.3	30.1	30.2	26.3	**30.9**	27.2
White Rose	**13.0**	16.8	13.3	14.8	13.3	**14.5**	10.0
Total production	**62.9**	66.3	70.6	74.6	63.6	**68.6**	58.0
Average sales price [1] (dollars per barrel)	**87.12**	78.78	76.88	78.69	77.71	**80.20**	76.86
International							
Production (kboe/d)							
North Sea							
Buzzard	**55.6**	58.6	49.3	58.6	59.9	**55.5**	47.8
Production from discontinued operations	**18.7**	25.2	22.7	27.5	31.1	**23.5**	28.7
Total North Sea	**74.3**	83.8	72.0	86.1	91.0	**79.0**	76.5
Other International							
Libya	**34.7**	35.4	35.4	35.4	26.0	**35.2**	32.6
Syria****	**16.9**	16.5	12.8	—	—	**11.6**	—
Production from discontinued operations	**—**	4.2	11.1	11.7	12.0	**6.7**	11.7
Total Other International	**51.6**	56.1	59.3	47.1	38.0	**53.5**	44.3
Total production	**125.9**	139.9	131.3	133.2	129.0	**132.5**	120.8
Average sales price from continuing operations [1] (dollars per boe)							
Buzzard	**85.46**	75.60	78.57	72.36	68.71	**77.91**	69.53
Other International	**83.06**	74.90	76.14	73.40	79.06	**78.07**	77.53
Total International and Offshore Production (kboe/d)	**188.8**	206.2	201.9	207.8	192.6	**201.1**	178.8

Footnotes, definitions and abbreviations, see page 26.

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Twelve months ended	
	Dec 31 2010	Sept 30 2010	June 30 2010	Mar 31 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
REFINING AND MARKETING							
Eastern North America							
Refined product sales (thousands of m^3/d)							
Transportation fuels							
Gasoline	**22.9**	22.5	22.5	21.0	23.0	**22.2**	14.6
Distillate	**13.7**	11.7	12.5	12.3	13.9	**12.4**	8.8
Total transportation fuel sales	**36.6**	34.2	35.0	33.3	36.9	**34.6**	23.4
Petrochemicals	**2.4**	2.5	2.8	2.2	1.2	**2.5**	0.8
Asphalt	**2.4**	3.7	3.0	1.8	2.0	**2.7**	1.5
Other	**5.3**	6.0	6.0	4.3	1.9	**5.5**	2.0
Total refined product sales	**46.7**	46.4	46.8	41.6	42.0	**45.3**	27.7
Crude oil supply and refining							
Processed at refineries (thousands of m^3/d)	**29.7**	30.7	30.6	31.0	28.3	**30.5**	29.6
Utilization of refining capacity (%)	**87**	90	90	91	83	**89**	87
Western North America							
Refined product sales (thousands of m^3/d)							
Transportation fuels							
Gasoline	**18.3**	19.9	19.2	18.1	18.4	**18.9**	13.0
Distillate	**23.2**	17.4	16.3	16.9	15.6	**18.5**	9.5
Total transportation fuel sales	**41.5**	37.3	35.5	35.0	34.0	**37.4**	22.5
Asphalt	**0.9**	1.5	1.5	1.2	0.9	**1.3**	1.3
Other	**2.0**	3.7	5.2	4.4	6.0	**3.8**	3.4
Total refined product sales	**44.4**	42.5	42.2	40.6	40.9	**42.5**	27.2
Crude oil supply and refining							
Processed at refineries (thousands of m^3/d)	**36.5**	36.6	31.7	33.5	33.4	**34.6**	33.6
Utilization of refining capacity (%)	**101**	101	87	92	96	**95**	97

Footnotes, definitions and abbreviations, see page 26.

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Twelve months ended	
	Dec 31 2010	Sept 30 2010	June 30 2010	Mar 31 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
NETBACKS – Continuing Operations							
Natural Gas (dollars per mcfe)							
Average price realized [8]	**4.40**	4.76	5.06	6.23	5.02	**5.16**	4.50
Royalties	**(0.45)**	(0.50)	(0.06)	(0.91)	(0.71)	**(0.49)**	(0.37)
Transportation costs	**(0.33)**	(0.39)	(0.55)	(0.37)	(0.45)	**(0.41)**	(0.41)
Operating costs	**(1.71)**	(1.53)	(1.55)	(1.30)	(1.43)	**(1.52)**	(1.39)
Operating netback	**1.91**	2.34	2.90	3.65	2.43	**2.74**	2.33
International and Offshore							
East Coast Canada (dollars per barrel)							
Average price realized [8]	**89.35**	81.06	78.99	80.79	79.69	**82.38**	79.07
Royalties	**(29.17)**	(25.49)	(28.45)	(28.78)	(25.26)	**(27.99)**	(23.82)
Transportation costs	**(2.23)**	(2.28)	(2.11)	(2.10)	(1.98)	**(2.18)**	(2.21)
Operating costs	**(7.57)**	(6.80)	(6.08)	(6.38)	(5.63)	**(6.68)**	(7.24)
Operating netback	**50.38**	46.49	42.35	43.53	46.82	**45.53**	45.80
North Sea – Buzzard (dollars per barrel)							
Average price realized [8]	**87.30**	77.43	80.35	74.19	70.38	**79.73**	71.64
Transportation costs	**(1.84)**	(1.83)	(1.78)	(1.83)	(1.67)	**(1.82)**	(2.11)
Operating costs	**(2.80)**	(2.90)	(3.57)	(3.09)	(2.90)	**(3.07)**	(2.88)
Operating netback	**82.66**	72.70	75.00	69.27	65.81	**74.84**	66.65
Other International (dollars per boe)							
Average price realized [8]	**82.74**	75.24	76.61	73.92	79.97	**78.30**	78.19
Royalties	**(18.37)**	(32.06)	(36.99)	(43.28)	(32.12)	**(35.06)**	(39.88)
Transportation costs	**0.32**	(0.34)	(0.47)	(0.52)	(0.91)	**(0.23)**	(0.66)
Operating costs	**(6.38)**	(4.72)	(7.40)	(3.29)	(5.12)	**(5.60)**	(3.39)
Operating netback	**58.31**	38.12	31.75	26.83	41.82	**37.41**	34.26

Footnotes, definitions and abbreviations, see page 26.

Quarterly Operating Summary (continued)

Non-GAAP Financial Measures

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

Definitions

(1) Average sales price	– This operating statistic is calculated before royalties (where applicable) and net of related transportation costs.
(2) Cash operating costs	– Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense and the cost of bitumen imported from third parties. Per barrel amounts are based on total production volumes. For a reconciliation of this non-GAAP financial measure see the fourth quarter Report to Shareholders.
(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.

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

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

**** Commercial production for Syria commenced on April 19, 2010.

Abbreviations

kbpd — 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
kboe/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

Consolidated Statements of Earnings

(unaudited)

($ millions)	Three months ended December 31 **2010**	2009	Twelve months ended December 31 **2010**	2009
Revenues				
Operating revenues	**9 173**	7 114	**33 198**	17 977
Less: Royalties (note 4)	**(351)**	(564)	**(1 937)**	(1 150)
Operating revenues (net of royalties)	**8 822**	6 550	**31 261**	16 827
Energy supply and trading activities	**650**	681	**2 700**	7 577
Interest and other income (note 5)	**317**	5	**389**	444
	9 789	7 236	**34 350**	24 848
Expenses				
Purchases of crude oil and products	**3 989**	2 886	**14 911**	7 388
Operating, selling and general	**2 290**	2 242	**7 810**	6 430
Energy supply and trading activities	**599**	524	**2 598**	7 381
Transportation	**185**	150	**656**	396
Depreciation, depletion and amortization (note 7)	**874**	757	**3 813**	1 860
Accretion of asset retirement obligations	**46**	42	**178**	136
Exploration	**37**	86	**197**	209
Loss (gain) on disposal of assets	**26**	54	**(107)**	66
Project start-up costs	**29**	13	**77**	51
Financing income (note 9)	**(176)**	(72)	**(30)**	(488)
	7 899	6 682	**30 103**	23 429
Earnings Before Income Taxes	**1 890**	554	**4 247**	1 419
Provisions for (Recovery of) Income Taxes (note 10)				
Current	**299**	192	**1 004**	841
Future	**294**	(114)	**555**	(628)
	593	78	**1 559**	213
Net Earnings from Continuing Operations	**1 297**	476	**2 688**	1 206
Net Earnings (Loss) from Discontinued Operations (note 6)	**56**	(19)	**883**	(60)
Net Earnings	**1 353**	457	**3 571**	1 146
Net Earnings from Continuing Operations per Common Share (dollars)				
Basic	**0.83**	0.30	**1.72**	1.01
Diluted	**0.82**	0.30	**1.71**	1.00
Net Earnings per Common Share (dollars), (note 11)				
Basic	**0.87**	0.29	**2.29**	0.96
Diluted	**0.86**	0.29	**2.27**	0.95
Cash dividends	**0.10**	0.10	**0.40**	0.30

Consolidated Statements of Comprehensive Income

(unaudited)

($ millions)	Three months ended December 31 **2010**	2009	Twelve months ended December 31 **2010**	2009
Net earnings	**1 353**	457	**3 571**	1 146
Other comprehensive income (loss), net of tax				
Change in foreign currency translation adjustment	**(235)**	(82)	**(503)**	(332)
Reclassification to net earnings	**9**	—	**53**	—
Loss on derivative contracts designated as cash flow hedges	**—**	(1)	**—**	—
Reclassification to net earnings	**—**	—	**(1)**	2
Comprehensive Income	**1 127**	374	**3 120**	816

Consolidated Balance Sheets

(unaudited)

($ millions)	**December 31 2010**	December 31 2009
Assets		
Current assets		
Cash and cash equivalents	**1 077**	505
Accounts receivable	**5 253**	3 703
Inventories	**3 141**	2 947
Income taxes receivable	**734**	587
Future income taxes	**210**	332
Assets of discontinued operations (note 6)	**98**	257
Total current assets	**10 513**	8 331
Property, plant and equipment, net	**55 290**	54 198
Other assets	**451**	491
Goodwill	**3 201**	3 201
Future income taxes	**56**	193
Assets of discontinued operations (note 6)	**658**	3 332
Total assets	**70 169**	69 746
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**2**	2
Current portion of long-term debt (note 15)	**518**	25
Accounts payable and accrued liabilities	**6 942**	6 307
Income taxes payable	**929**	1 254
Future income taxes	**37**	18
Liabilities of discontinued operations (note 6)	**98**	242
Total current liabilities	**8 526**	7 848
Long-term debt (note 15)	**11 669**	13 855
Accrued liabilities and other	**4 154**	4 372
Future income taxes	**8 615**	8 367
Liabilities of discontinued operations (note 6)	**484**	1 193
Shareholders' equity	**36 721**	34 111
Total liabilities and shareholders' equity	**70 169**	69 746

Shareholders' Equity

	Number (thousands)		Number (thousands)	
Share capital	**1 565 489**	**20 188**	1 559 778	20 053
Contributed surplus		**505**		526
Accumulated other comprehensive income (loss) (note 17)		**(684)**		(233)
Retained earnings		**16 712**		13 765
Total shareholders' equity		**36 721**		34 111

Consolidated Statements of Cash Flows

(unaudited)

($ millions)	Three months ended December 31 2010	2009	Twelve months ended December 31 2010	2009
Operating Activities				
Net earnings from continuing operations	**1 297**	476	**2 688**	1 206
Adjustments for:				
Depreciation, depletion and amortization	**874**	757	**3 813**	1 860
Future income taxes	**294**	(114)	**555**	(628)
Accretion of asset retirement obligations	**46**	42	**178**	136
Unrealized foreign exchange gain on U.S. dollar denominated long-term debt (note 9)	**(290)**	(201)	**(426)**	(858)
Change in fair value of derivative contracts (note 8)	**(32)**	(59)	**(285)**	980
Loss (gain) on disposal of assets	**26**	54	**(107)**	66
Stock-based compensation	**114**	34	**114**	262
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	—	**—**	(438)
Other	**(205)**	(151)	**(446)**	(278)
Exploration expenses	**6**	43	**80**	126
Change in non-cash working capital related to operating activities (note 12)	**(479)**	442	**(1 230)**	(237)
Cash flow provided by continuing operations	**1 651**	1 323	**4 934**	2 197
Cash flow provided by discontinued operations	**93**	150	**552**	378
Cash flow provided by operating activities	**1 744**	1 473	**5 486**	2 575
Investing Activities				
Capital and exploration expenditures	**(1 867)**	(1 430)	**(5 833)**	(4 020)
Other investments	**22**	(3)	**3**	(9)
Proceeds from disposal of assets	**42**	112	**307**	148
Cash acquired through business combination	**—**	—	**—**	248
Change in non-cash working capital related to investing activities	**54**	(83)	**(196)**	(791)
Cash flow used in continuing investing activities	**(1 749)**	(1 404)	**(5 719)**	(4 424)
Cash flow provided by (used in) discontinued investing activities	**198**	(126)	**2 607**	(247)
Cash flow used in investing activities	**(1 551)**	(1 530)	**(3 112)**	(4 671)
Financing Activities				
Change in short-term debt	**—**	(1)	**—**	—
Change in revolving-term debt	**415**	116	**(1 257)**	2 325
Issuance of common shares under stock option plan	**34**	11	**81**	41
Dividends paid on common shares	**(149)**	(152)	**(611)**	(401)
Cash flow provided by (used in) financing activities	**300**	(26)	**(1 787)**	1 965
Increase (Decrease) in Cash and Cash Equivalents	**493**	(83)	**587**	(131)
Effect of Foreign Exchange on Cash and Cash Equivalents	**(14)**	1	**(15)**	(24)
Cash and Cash Equivalents at Beginning of Period	**598**	587	**505**	660
Cash and Cash Equivalents at End of Period	**1 077**	505	**1 077**	505

Consolidated Statements of Changes in Shareholders' Equity

(unaudited)

($ millions)	Share Capital	Contributed Surplus	Accumulated Other Comprehensive Income (Loss)	Retained Earnings
At December 31, 2008	1 113	288	97	13 025
Net earnings	—	—	—	1 146
Dividends paid on common shares	—	—	—	(401)
Issued for cash under stock option plan	57	(16)	—	—
Issued under dividend reinvestment plan	5	—	—	(5)
Stock-based compensation expense	—	103	—	—
Issued for Petro-Canada acquisition (note 2)	18 878	—	—	—
Fair value of Petro-Canada stock options exchanged for Suncor stock options	—	147	—	—
Income tax benefit of stock option deduction in the U.S.	—	4	—	—
Change in accumulated other comprehensive income (loss)	—	—	(330)	—
At December 31, 2009	20 053	526	(233)	13 765
Net earnings	**—**	**—**	**—**	**3 571**
Dividends paid on common shares	**—**	**—**	**—**	**(611)**
Issued for cash under stock option plans	**122**	**(34)**	**—**	**—**
Issued under dividend reinvestment plan	**13**	**—**	**—**	**(13)**
Stock-based compensation expense	**—**	**13**	**—**	**—**
Change in accumulated other comprehensive income (loss)	**—**	**—**	**(451)**	**—**
At December 31, 2010	**20 188**	**505**	**(684)**	**16 712**

Schedules of Segmented Data from Continuing Operations

(unaudited)

Three months ended December 31

($ millions)	Oil Sands 2010	Oil Sands 2009	Natural Gas 2010	Natural Gas 2009	International and Offshore 2010	International and Offshore 2009	Refining and Marketing 2010	Refining and Marketing 2009	Corporate, Energy Trading and Eliminations 2010	Corporate, Energy Trading and Eliminations 2009	Total 2010	Total 2009
EARNINGS												
Revenues												
Operating revenues	**1 934**	1 182	**135**	144	**1 313**	1 052	**5 778**	4 694	**13**	42	**9 173**	7 114
Intersegment revenues	**881**	1 082	**37**	67	**126**	62	**43**	49	**(1 087)**	(1 260)	**—**	—
Less: Royalties	**(139)**	(280)	**(18)**	(30)	**(194)**	(254)	**—**	—	**—**	—	**(351)**	(564)
Operating revenues (net of royalties)	**2 676**	1 984	**154**	181	**1 245**	860	**5 821**	4 743	**(1 074)**	(1 218)	**8 822**	6 550
Energy supply and trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**650**	681	**650**	681
Interest and other income	**13**	2	**4**	—	**256**	1	**5**	—	**39**	2	**317**	5
	2 689	1 986	**158**	181	**1 501**	861	**5 826**	4 743	**(385)**	(535)	**9 789**	7 236
Expenses												
Purchases of crude oil and products	**342**	83	**—**	—	**139**	17	**4 555**	3 889	**(1 047)**	(1 103)	**3 989**	2 886
Operating, selling and general	**1 271**	1 300	**104**	87	**133**	125	**587**	530	**195**	200	**2 290**	2 242
Energy supply and trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**599**	524	**599**	524
Transportation	**88**	70	**12**	19	**22**	23	**57**	43	**6**	(5)	**185**	150
Depreciation, depletion and amortization	**297**	300	**126**	113	**302**	218	**123**	114	**26**	12	**874**	757
Accretion of asset retirement obligations	**30**	29	**9**	6	**7**	7	**—**	—	**—**	—	**46**	42
Exploration	**—**	2	**1**	42	**36**	42	**—**	—	**—**	—	**37**	86
Loss (gain) on disposal of assets	**3**	53	**(6)**	—	**2**	—	**(11)**	1	**38**	—	**26**	54
Project start-up costs	**29**	13	**—**	—	**—**	—	**—**	—	**—**	—	**29**	13
Financing expenses (income)	**(5)**	1	**2**	—	**10**	(2)	**7**	4	**(190)**	(75)	**(176)**	(72)
	2 055	1 851	**248**	267	**651**	430	**5 318**	4 581	**(373)**	(447)	**7 899**	6 682
Earnings (loss) before income taxes	**634**	135	**(90)**	(86)	**850**	431	**508**	162	**(12)**	(88)	**1 890**	554
Income taxes	**147**	(101)	**(25)**	(31)	**398**	201	**136**	11	**(63)**	(2)	**593**	78
Net earnings (loss) from continuing operations	**487**	236	**(65)**	(55)	**452**	230	**372**	151	**51**	(86)	**1 297**	476
CAPITAL AND EXPLORATION EXPENDITURES – continuing operations	**(1 067)**	(734)	**(57)**	(39)	**(319)**	(357)	**(272)**	(239)	**(152)**	(61)	**(1 867)**	(1 430)

Schedules of Segmented Data from Continuing Operations (continued)

(unaudited)

	Twelve months ended December 31											
	Oil Sands		Natural Gas		International and Offshore		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
($ millions)	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009
EARNINGS												
Revenues												
Operating revenues	**7 028**	4 135	**682**	338	**4 654**	1 526	**20 769**	11 800	**65**	178	**33 198**	17 977
Intersegment revenues	**2 758**	2 609	**124**	121	**593**	159	**249**	51	**(3 724)**	(2 940)	**—**	—
Less: Royalties	**(681)**	(645)	**(76)**	(36)	**(1 180)**	(469)	**—**	—	**—**	—	**(1 937)**	(1 150)
Operating revenues (net of royalties)	**9 105**	6 099	**730**	423	**4 067**	1 216	**21 018**	11 851	**(3 659)**	(2 762)	**31 261**	16 827
Energy supply and trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**2 700**	7 577	**2 700**	7 577
Interest and other income	**318**	440	**4**	—	**256**	1	**44**	—	**(233)**	3	**389**	444
	9 423	6 539	**734**	423	**4 323**	1 217	**21 062**	11 851	**(1 192)**	4 818	**34 350**	24 848
Expenses												
Purchases of crude oil and products	**1 070**	325	**—**	—	**302**	33	**17 100**	9 607	**(3 561)**	(2 577)	**14 911**	7 388
Operating, selling and general	**4 545**	4 277	**338**	233	**414**	164	**2 192**	1 284	**321**	472	**7 810**	6 430
Energy supply and trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**2 598**	7 381	**2 598**	7 381
Transportation	**291**	248	**94**	41	**89**	38	**200**	87	**(18)**	(18)	**656**	396
Depreciation, depletion and amortization	**1 318**	922	**773**	287	**1 172**	299	**475**	317	**75**	35	**3 813**	1 860
Accretion of asset retirement obligations	**120**	111	**29**	14	**27**	10	**2**	1	**—**	—	**178**	136
Exploration	**6**	10	**14**	125	**177**	74	**—**	—	**—**	—	**197**	209
Loss (gain) on disposal of assets	**14**	70	**(132)**	(20)	**2**	—	**(30)**	16	**39**	—	**(107)**	66
Project start-up costs	**74**	51	**—**	—	**3**	—	**—**	—	**—**	—	**77**	51
Financing expenses (income)	**(1)**	1	**(1)**	—	**(18)**	(1)	**9**	4	**(19)**	(492)	**(30)**	(488)
	7 437	6 015	**1 115**	680	**2 168**	617	**19 948**	11 316	**(565)**	4 801	**30 103**	23 429
Earnings (loss) before income taxes	**1 986**	524	**(381)**	(257)	**2 155**	600	**1 114**	535	**(627)**	17	**4 247**	1 419
Income taxes	**494**	(33)	**(104)**	(72)	**1 041**	277	**313**	128	**(185)**	(87)	**1 559**	213
Net earnings (loss) from continuing operations	**1 492**	557	**(277)**	(185)	**1 114**	323	**801**	407	**(442)**	104	**2 688**	1 206
CAPITAL AND EXPLORATION EXPENDITURES – continuing operations	**(3 709)**	(2 831)	**(170)**	(228)	**(927)**	(511)	**(667)**	(380)	**(360)**	(70)	**(5 833)**	(4 020)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

1. ACCOUNTING POLICIES

These interim consolidated financial statements of Suncor Energy Inc. (Suncor or the company) have been prepared in accordance with Canadian generally accepted accounting principles and follow the same accounting policies and methods of computation as, and should be read in conjunction with, the most recent annual financial statements. Certain information and disclosures normally required to be included in notes to the annual consolidated financial statements have been condensed or omitted.

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

2. BUSINESS COMBINATION WITH PETRO-CANADA

(a) Overview

On August 1, 2009, Suncor completed its merger with Petro-Canada. The company has accounted for this business combination as prescribed by Canadian Institute of Chartered Accountants (CICA) Handbook section 1581 "Business Combinations". As the acquirer, the company is required to recognize Petro-Canada assets and liabilities as at August 1, 2009. The results of Petro-Canada operations are included in the consolidated financial statements of the company from August 1, 2009.

(b) Final Allocation of Purchase Price

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

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

The purchase price allocation was based on best estimates by Suncor's management and was based principally on valuations prepared by independent valuation specialists. Management finalized the purchase price allocation during the second quarter of 2010 and did not make any amendments to the preliminary allocation.

3. CHANGE IN SEGMENTED DISCLOSURES

During the first quarter of 2010, as a result of planned divestitures of the company's assets in Trinidad and Tobago, The Netherlands and certain assets in the United Kingdom (U.K.) (described in note 6), the company combined its International and East Coast Canada segments into one new segment, International and Offshore. Continuing operations for the International and Offshore segment are comprised of activity offshore Newfoundland and Labrador, including interests in the Hibernia, Terra Nova, White Rose and Hebron oilfields, and the exploration for, and production of, crude oil and natural gas in the U.K., Norway, Libya and Syria.

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

4. BITUMEN VALUATION METHODOLOGY

In the fourth quarter of 2010, the Minister of Energy for Alberta provided notice to the company for the quality adjustment to be used under the Bitumen Valuation Methodology (Ministerial) Regulations for the interim period January 1, 2009 to December 31, 2010. As a result, the company recognized a royalty recovery of approximately $140 million.

The company continues to negotiate final adjustments to the bitumen valuation calculation for the 2009 and 2010 interim period and for the term of the Suncor Royalty Amending Agreement that expires December 31, 2015.

5. TERRA NOVA REDETERMINATION

In the fourth quarter of 2010, the joint owners of the Terra Nova oilfield finalized the redetermination of working interests required under the Terra Nova Development and Operating Agreement following field payout on February 1, 2005. Suncor's working interest increased to 37.675% from 33.990%, and the other owners have agreed to reimburse the company for its increased working interest from February 1, 2005 to December 31, 2010. As a result, the company has recognized a $295 million gain in Other Income.

Suncor's financial presentation will reflect the increased working interest in Terra Nova beginning January 1, 2011.

6. DISCONTINUED OPERATIONS

The company is divesting certain non-core assets as part of its continuing strategic alignment.

Natural Gas

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 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.

International and Offshore

In the third quarter of 2010, the company completed the Trinidad and Tobago asset sale 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).

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). The company expects to close the remaining agreed sales of non-core U.K. offshore assets for gross proceeds of £184 million in the first quarter of 2011.

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

	Three months ended December 31					
	Natural Gas		International and Offshore		Total	
($ millions)	**2010**	2009	**2010**	2009	**2010**	2009
Revenues						
Operating revenues [1]	**3**	159	**147**	288	**150**	447
Less: Royalties	**—**	(23)	**—**	—	**—**	(23)
Operating revenues (net of royalties)	**3**	136	**147**	288	**150**	424
Gain (loss) on disposal of assets	**(4)**	—	**3**	—	**(1)**	—
	(1)	136	**150**	288	**149**	424
Expenses						
Operating, selling and general	**2**	38	**31**	97	**33**	135
Transportation	**—**	8	**5**	9	**5**	17
Depreciation, depletion and amortization	**—**	77	**—**	238	**—**	315
Accretion of asset retirement obligations	**—**	4	**4**	6	**4**	10
Exploration	**—**	2	**4**	12	**4**	14
Financing expenses	**—**	—	**—**	2	**—**	2
	2	129	**44**	364	**46**	493
Earnings (loss) before income taxes	**(3)**	7	**106**	(76)	**103**	(69)
Income taxes	**(1)**	2	**48**	(52)	**47**	(50)
Net earnings (loss)	**(2)**	5	**58**	(24)	**56**	(19)

(1) Operating revenues reported in Natural Gas include sales to other operating segments that would be eliminated upon consolidation in the Consolidated Statements of Earnings. These were nil in the three months ended December 31, 2010 (2009 – $24 million).

	Three months ended December 31	
(dollars)	**2010**	2009
Basic earnings per share from discontinued operations	**0.04**	(0.01)
Diluted earnings per share from discontinued operations	**0.04**	(0.01)

	Twelve months ended December 31					
	Natural Gas		**International and Offshore**		**Total**	
($ millions)	**2010**	2009	**2010**	2009	**2010**	2009
Revenues						
Operating revenues [1]	**280**	307	**693**	407	**973**	714
Less: Royalties	**(41)**	(49)	**—**	—	**(41)**	(49)
Operating revenues (net of royalties)	**239**	258	**693**	407	**932**	665
Gain on disposal of assets	**642**	—	**172**	—	**814**	—
	881	258	**865**	407	**1 746**	665
Expenses						
Operating, selling and general	**66**	89	**119**	150	**185**	239
Transportation	**24**	17	**23**	14	**47**	31
Depreciation, depletion and amortization	**95**	161	**169**	285	**264**	446
Accretion of asset retirement obligations	**8**	8	**19**	11	**27**	19
Exploration	**1**	2	**20**	57	**21**	59
Financing expenses	**7**	—	**11**	1	**18**	1
	201	277	**361**	518	**562**	795
Earnings (loss) before income taxes	**680**	(19)	**504**	(111)	**1 184**	(130)
Income taxes	**174**	(5)	**127**	(65)	**301**	(70)
Net earnings (loss)	**506**	(14)	**377**	(46)	**883**	(60)

(1) Operating revenues reported in Natural Gas include sales to other operating segments that would be eliminated upon consolidation in the Consolidated Statements of Earnings. These totalled $62 million in the twelve months ended December 31, 2010 (2009 – $33 million).

	Twelve months ended December 31	
(dollars)	**2010**	2009
Basic earnings per share from discontinued operations	**0.57**	(0.05)
Diluted earnings per share from discontinued operations	**0.56**	(0.05)

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

	Natural Gas		**International and Offshore**		**Total**	
($ millions)	**December 31 2010**	December 31 2009	**December 31 2010**	December 31 2009	**December 31 2010**	December 31 2009
Assets						
Current assets	**—**	34	**98**	223	**98**	257
Property, plant and equipment, net	**—**	1 600	**658**	1 732	**658**	3 332
Total assets	**—**	1 634	**756**	1 955	**756**	3 589
Liabilities						
Current liabilities	**—**	64	**98**	178	**98**	242
Accrued liabilities and other	**—**	286	**302**	404	**302**	690
Future income taxes	**—**	31	**182**	472	**182**	503
Total liabilities	**—**	381	**582**	1 054	**582**	1 435

7. ASSET WRITE-DOWNS

During the second quarter of 2010, the company recognized a write-down of $189 million related to certain extraction equipment in the Oil Sands operating segment. Also during the second quarter of 2010, the company recognized a charge of $44 million in the Natural Gas operating segment to reflect the write-down of certain Western Canada and Alaska land leases.

During the third quarter of 2010, the company recognized a write-down of $106 million related to certain North Sea assets in the International and Offshore operating segment. An agreement to sell these assets was entered into during the quarter and the assets were written down to reflect fair value less cost to sell. Also during the third quarter of 2010, the company recognized a charge of $222 million to reflect the write-down of certain assets in the Natural Gas operating segment to reflect fair value based on discounted future cash flows.

These charges are included in depreciation, depletion and amortization expenses and net earnings from discontinued operations in the Consolidated Statements of Earnings.

8. FINANCIAL INSTRUMENTS AND FINANCIAL RISK FACTORS

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

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

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

(a) Balance Sheet Financial Instruments

The company's financial instruments consist of cash and cash equivalents, accounts receivable, derivative contracts, current liabilities (except for the current portions of income taxes), long-term debt, and a portion of non-current accrued liabilities and other. Unless otherwise noted, carrying values reflect the current fair value of the company's financial instruments.

The estimated fair values of financial instruments have been determined based on the company's assessment of available market information and appropriate valuation methodologies based on industry accepted third-party models; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction. The company characterizes inputs used in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable in the market (see page 77 of Suncor's 2009 Annual Report for further detail). As at December 31, 2010, there were no significant changes to the distribution of the fair value hierarchy used to value financial instruments.

The company's long-term debt is recorded at amortized cost using the effective interest method, with the exception of the portion of debt that is recorded at fair value as part of a fair value hedging relationship. Upon initial recognition, the cost of the debt is its fair value, adjusted for any associated transaction costs. Gains or losses on our U.S. dollar denominated long-term debt resulting from changes in the exchange rate are recognized in the period in which they occur. At December 31, 2010, the carrying value of the fixed-term debt accounted for under the amortized cost method was $9.7 billion (December 31, 2009 – $10.1 billion) and the fair value was $10.7 billion (December 31, 2009 – $10.7 billion).

(b) Hedge Accounting

Fair Value Hedges

At December 31, 2010, the company had interest rate swaps classified as fair value hedges outstanding until August 2011, relating to $200 million of its fixed-rate debt. The fair value of these swaps totalled $8 million at December 31, 2010 and was recorded in accounts receivable (December 31, 2009 – $18 million). There was no ineffectiveness recognized on these interest rate swaps during the three and twelve month periods ended December 31, 2010 and December 31, 2009.

(c) Other Derivatives

Risk Management Derivatives

The company periodically enters into derivative contracts which although not accounted for as hedges because they have not been documented as such, or do not qualify under GAAP, are believed to be economically effective at mitigating exposure to commodity price movements and are a component of Suncor's overall risk management program. These derivative contracts include crude oil, natural gas, refined products and foreign exchange contracts. The earnings impact associated with these contracts for the three month period ended December 31, 2010, was a loss of $5 million (2009 – a loss of $134 million). During the twelve month period ended December 31, 2010, the earnings impact was a gain of $89 million (2009 – loss of $1,024 million).

Energy Trading Derivatives

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

The earnings impact associated with these contracts for the three month period ended December 31, 2010, was a gain of $19 million (2009 – a loss of $17 million). During the twelve month period ended December 31, 2010, the earnings impact was a gain of $81 million (2009 – loss of $70 million).

Change in Fair Value of Other Derivatives

($ millions)	Risk Management	Energy Trading	Total
Fair value of contracts at December 31, 2009	(312)	(47)	(359)
Fair value of contracts realized during the period	**236**	**(121)**	**115**
Changes in fair value during the period	**89**	**81**	**170**
Fair value of contracts outstanding at December 31, 2010 [(a),(b)]	**13**	**(87)**	**(74)**

(a) As at December 31, 2010, of the total unrealized derivatives, $19 million is recorded in accounts receivable (December 31, 2009 – $213 million) in the Consolidated Balance Sheets.

(b) As at December 31, 2010, of the total unrealized derivatives, $93 million is recorded in accounts payable and accrued liabilities (December 31, 2009 – $572 million) in the Consolidated Balance Sheets.

Financial Risk Factors

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

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

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

9. FINANCING EXPENSES (INCOME)

	Three months ended December 31		Twelve months ended December 31	
($ millions)	**2010**	2009	**2010**	2009
Interest on debt	**170**	182	**691**	573
Capitalized interest	**(98)**	(42)	**(301)**	(136)
Interest expense	**72**	140	**390**	437
Unrealized foreign exchange gain on U.S. dollar denominated long-term debt	**(290)**	(201)	**(426)**	(858)
Foreign exchange gains and other	**42**	(11)	**6**	(67)
Total financing income from continuing operations (1)	**(176)**	(72)	**(30)**	(488)

(1) For the three months ended December 31, 2010, financing expense of $nil (2009 – financing expense of $2 million) has been reclassified to net earnings from discontinued operations. For the twelve months ended December 31, 2010, financing expense of $18 million (2009 – financing expense of $1 million) has been reclassified to net earnings from discontinued operations.

10. INCOME TAXES

	Three months ended December 31		Twelve months ended December 31	
($ millions)	**2010**	2009	**2010**	2009
Provision for (recovery of) income taxes:				
Current:				
Canada	**1**	28	**57**	599
Foreign	**298**	164	**947**	242
Future:				
Canada	**274**	(139)	**569**	(699)
Foreign	**20**	25	**(14)**	71
Total provision for income taxes from continuing operations (1)	**593**	78	**1 559**	213

(1) For the three months ended December 31, 2010, income tax expense of $47 million (2009 – income tax recovery of $50 million) has been reclassified to net earnings from discontinued operations. For the twelve months ended December 31, 2010, income tax expense of $301 million (2009 – income tax recovery of $70 million) has been reclassified to net earnings from discontinued operations

In the fourth quarter of 2009, the Ontario provincial government substantively enacted a 4% reduction to its provincial corporate tax rates. Accordingly, the company recognized a reduction in future income tax expense of $148 million related to the revaluation of its opening future income tax balances.

In the third quarter of 2009, the provision for future income tax increased by $152 million due in part to the merger. The combined provincial allocation of both entities caused an increase to the future income tax rate, the impact of which is recorded in net earnings.

11. RECONCILIATION OF BASIC AND DILUTED EARNINGS PER COMMON SHARE

	Three months ended December 31		Twelve months ended December 31	
($ millions)	**2010**	2009	**2010**	2009
Net earnings	**1 353**	457	**3 571**	1 146
(millions of common shares)				
Weighted-average number of common shares	**1 564**	1 560	**1 562**	1 198
Dilutive securities:				
Options issued under stock-based compensation plans	**11**	14	**12**	13
Weighted-average number of diluted common shares	**1 575**	1 574	**1 574**	1 211
(dollars per common share)				
Basic earnings per share [a]	**0.87**	0.29	**2.29**	0.96
Diluted earnings per share [b]	**0.86**	0.29	**2.27**	0.95

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

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

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

12. SUPPLEMENTAL CASH FLOW INFORMATION

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

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

	Three months ended December 31		Twelve months ended December 31	
($ millions)	**2010**	2009	**2010**	2009[1]
Operating activities				
Accounts receivable	**(809)**	152	**(683)**	105
Inventories	**(30)**	(209)	**(190)**	(585)
Accounts payable and accrued liabilities	**285**	501	**101**	280
Taxes payable/receivable	**75**	(2)	**(458)**	(37)
	(479)	442	**(1 230)**	(237)

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

	Three months ended December 31		Twelve months ended December 31	
($ millions)	**2010**	2009	**2010**	2009
Interest paid	**266**	284	**839**	581
Income taxes paid	**626**	196	**1 193**	872

13. EMPLOYEE FUTURE BENEFITS LIABILITY

The following is the net periodic benefit cost for the three and twelve month periods ended December 31:

	Pension Benefits			
	Three months ended December 31		Twelve months ended December 31	
($ millions)	**2010**	2009	**2010**	2009
Current service costs	**21**	18	**85**	67
Interest costs	**42**	39	**168**	96
Expected return on plan assets	**(35)**	(32)	**(142)**	(76)
Amortization of net actuarial loss	**1**	6	**7**	21
Net periodic benefit cost	**29**	31	**118**	108

	Other Post-Retirement Benefits			
	Three months ended December 31		Twelve months ended December 31	
($ millions)	**2010**	2009	**2010**	2009
Current service costs	**2**	2	**8**	7
Interest costs	**6**	6	**25**	15
Net periodic benefit cost	**8**	8	**33**	22

14. SHARE CAPITAL

Issued

	Common Shares	
	Number (thousands)	Amount ($ millions)
Balance as at December 31, 2009	1 559 778	20 053
Issued for cash under stock option plans	**5 292**	**122**
Issued under dividend reinvestment plan	**419**	**13**
Balance as at December 31, 2010	**1 565 489**	**20 188**

Stock-Based Compensation

(a) Stock Option Plans

(i) Discontinued Plans

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

(ii) Suncor Energy Inc. Stock Options

This plan replaced the pre-merger stock option plans of legacy Suncor and legacy Petro-Canada. Outstanding options that are cancelled, expire or otherwise result in no underlying common share being issued, will be available for issuance as options under this plan. These options have a seven-year life and vest annually over a three-year period.

Options granted under this plan before August 1, 2010 included a tandem stock appreciation right. Effective August 1, 2010, options granted under this plan no longer include tandem stock appreciation rights. The company granted 1,000 options under this plan during the fourth quarter of 2010.

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

	Number (thousands)	Weighted-Average Exercise Price ($)
Outstanding, December 31, 2009	72 024	32.52
Granted	**4 297**	**31.86**
Exercised	**(5 292)**	**15.49**
Forfeited/expired	**(3 391)**	**42.51**
Outstanding, December 31, 2010	**67 638**	**32.94**

(b) Stock Appreciation Rights (SARs)

(i) Discontinued Plan

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

(ii) Suncor Energy Inc. Stock Appreciation Rights

SARs have a seven-year life and vest annually over a three-year period. The company did not grant any SARs under this plan during the fourth quarter of 2010.

Changes in the number of outstanding SARs were as follows:

	Number (thousands)	Weighted-Average Exercise Price ($)
Outstanding, December 31, 2009	14 065	28.63
Granted	**353**	**31.85**
Exercised	**(734)**	**24.00**
Forfeited	**(2 399)**	**28.99**
Outstanding, December 31, 2010	**11 285**	**28.97**

(c) Share Unit Plans

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

Changes in the number of outstanding units were as follows:

	Number (thousands)		
	PSU	RSU	DSU
Outstanding, December 31, 2009	3 247	4 250	2 616
Granted	**1 673**	**2 838**	**80**
Redeemed	**(282)**	**(118)**	**(426)**
Forfeited	**(917)**	**(563)**	**—**
Reinvested	**26**	**43**	**29**
Outstanding, December 31, 2010	**3 747**	**6 450**	**2 299**

Stock-Based Compensation Expense (Recovery)

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

	Three months ended December 31		Twelve months ended December 31	
($ millions)	**2010**	2009	**2010**	2009
Stock option plans	**33**	32	**53**	148
SARs	**39**	10	**27**	35
PSUs	**14**	11	**21**	30
RSUs	**33**	(7)	**90**	50
DSUs	**11**	—	**4**	30
Total stock-based compensation expense	**130**	46	**195**	293

15. LONG-TERM DEBT AND CREDIT FACILITIES

($ millions)	**December 31 2010**	December 31 2009
Fixed-term debt, redeemable at the option of the company		
6.85% Notes, denominated in U.S. dollars, due in 2039 (US$750)	**746**	785
6.80% Notes, denominated in U.S. dollars, due in 2038 (US$900)	**922**	972
6.50% Notes, denominated in U.S. dollars, due in 2038 (US$1150)	**1 144**	1 204
5.95% Notes, denominated in U.S. dollars, due in 2035 (US$600)	**552**	578
5.95% Notes, denominated in U.S. dollars, due in 2034 (US$500)	**497**	523
5.35% Notes, denominated in U.S. dollars, due in 2033 (US$300)	**255**	266
7.15% Notes, denominated in U.S. dollars, due in 2032 (US$500)	**497**	523
6.10% Notes, denominated in U.S. dollars, due in 2018 (US$1250)	**1 243**	1 308
6.05% Notes, denominated in U.S. dollars, due in 2018 (US$600)	**609**	643
5.00% Notes, denominated in U.S. dollars, due in 2014 (US$400)	**406**	429
4.00% Notes, denominated in U.S. dollars, due in 2013 (US$300)	**298**	313
7.00% Debentures, denominated in U.S. dollars, due in 2028 (US$250)	**257**	271
7.875% Debentures, denominated in U.S. dollars, due in 2026 (US$275)	**307**	325
9.25% Debentures, denominated in U.S. dollars, due in 2021 (US$300)	**375**	402
5.39% Series 4 Medium Term Notes, due in 2037	**600**	600
5.80% Series 4 Medium Term Notes, due in 2018	**700**	700
6.70% Series 2 Medium Term Notes, due in August 2011	**500**	500
	9 908	10 342
Revolving-term debt, with variable interest rates		
Commercial paper, bankers' acceptances and LIBOR loans	**1 982**	3 244
Total unsecured long-term debt	**11 890**	13 586
Secured long-term debt	**13**	13
Capital leases	**335**	326
Debt fair value adjustment for interest swaps	**8**	18
Deferred financing costs	**(59)**	(63)
	12 187	13 880
Current portion of long-term debt		
6.70% Series 2 Medium Term Notes	**(500)**	—
Capital leases	**(10)**	(14)
Debt fair value adjustment for interest swaps	**(8)**	(11)
Total current portion of long-term debt	**(518)**	(25)
Total long-term debt	**11 669**	13 855

At December 31, 2010, unutilized lines of credit were $5 289 million, as follows:

($ millions)	2010
Facility that has a term period of one year and expires in 2011	**4**
Facility that is fully revolving for a period of four years and expires in 2013	**199**
Facilities that are fully revolving for a period of five years and expire in 2013	**7 320**
Facilities that can be terminated at any time at the option of the lenders	**461**
Total available credit facilities	**7 984**
Credit facilities supporting outstanding commercial paper, bankers' acceptances and LIBOR loans	**(1 982)**
Credit facilities supporting letters of credit	**(713)**
Total unutilized credit facilities	**5 289**

16. CAPITAL STRUCTURE FINANCIAL POLICIES

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

The company's capital is monitored through net debt to cash flow from operations[(1)] and total debt to total debt plus shareholders' equity.

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

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

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

During the fourth quarter of 2010, the company's strategy was to maintain the measure set out in the following schedule. The company believes that maintaining this capital target helps to provide the company access to capital at a reasonable cost by maintaining solid investment-grade credit ratings.

At December 31 ($ millions)	Capital Measure Target	2010	2009
Components of ratios			
Short-term debt		**2**	2
Current portion of long-term debt		**518**	25
Long-term debt		**11 669**	13 855
Total debt		**12 189**	13 882
Less: Cash and cash equivalents		**1 077**	505
Net debt		**11 112**	13 377
Shareholders' equity		**36 721**	34 111
Total capitalization (total debt plus shareholders' equity)		**48 910**	47 993
Cash flow from operations[(1)] (trailing twelve months)		**6 656**	2 799
Net debt to cash flow from operations	<2.0 times	**1.7**	4.8
Total debt to total debt plus shareholders' equity		**25%**	29%

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

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

17. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

($ millions)	**December 31 2010**	December 31 2009
Unrealized foreign currency translation adjustment	**(698)**	(248)
Unrealized gains on derivative hedging activities	**14**	15
Total	**(684)**	(233)

18. JOINT VENTURE WITH TOTAL

On December 17, 2010, Suncor announced that it has entered into a joint venture with Total E&P Canada Ltd (Total). The two companies will jointly develop the Fort Hills and Joslyn oil sands mining projects and restart construction of the Voyageur upgrader.

Total will acquire a 49% interest in Suncor's Voyageur upgrader, and an additional 19.2% in the Fort Hills project, reducing Suncor's interest from 60% to 40.8%. In return, Suncor will acquire a 36.75% interest in the Joslyn project and receive cash consideration of approximately $1.75 billion.

The agreement is subject to certain regulatory and other approvals, with closing targeted in the first quarter of 2011.

SUNCOR ENERGY

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