SUNCOR ENERGY INC. **2009** ANNUAL REPORT

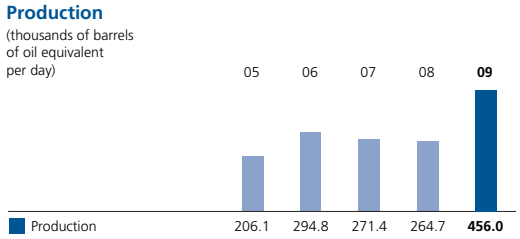
SUNCOR ENERGY is Canada's premier integrated energy company. Suncor's operations include oil sands development and upgrading, conventional and offshore oil and gas production, petroleum refining, and product marketing under the Petro-Canada brand. While working to responsibly develop petroleum resources, Suncor is also developing a growing renewable energy portfolio. Suncor's common shares (symbol: SU) are listed on the Toronto and New York stock exchanges.

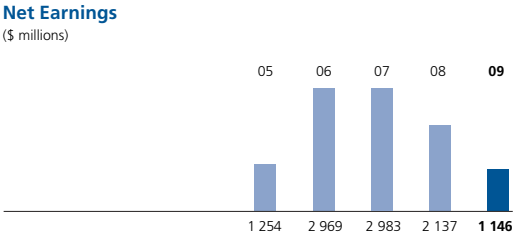
2 message to shareholders
5 our scorecard
6 management's discussion and analysis
- 7 suncor overview and strategic priorities
- 10 consolidated financial analysis
- 13 liquidity and capital resources
- 15 significant capital project update
- 16 royalties
- 20 risk factors affecting performance
- 23 critical accounting estimates
- 29 changes in accounting policies
- 33 oil sands
- 38 natural gas
- 41 east coast canada
- 43 international
- 46 refining and marketing
- 49 corporate, energy trading and eliminations
- 51 outlook
- 52 non-gaap financial measures

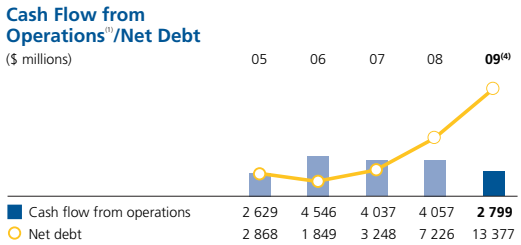
55 management's statement of responsibility for financial reporting
56 management's report on internal control over financial reporting
57 independent auditors' report
59 summary of significant accounting policies
64 consolidated financial statements and notes
101 quarterly summary
107 five-year financial summary
109 supplemental financial and operating information
114 share trading information
115 investor information
119 directors and corporate officers

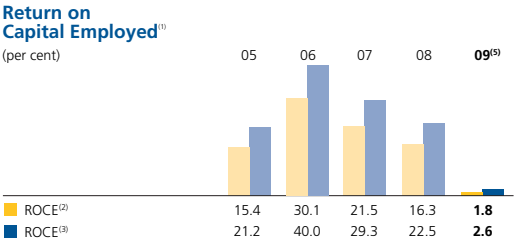
This annual report contains forward-looking statements, including statements about future plans for production growth, that are based on our assumptions and that involve risks and uncertainties. Actual results may differ materially. See page 54 for additional information. All financial information is reported in accordance with Canadian generally accepted accounting principles (GAAP) and in Canadian dollars unless noted otherwise. Financial measures not prescribed by GAAP include cash flow from operations, return on capital employed and cash operating costs. See page 52 and 53 for more details. Natural gas converts to crude oil equivalent at a ratio of six thousand cubic feet to one barrel. Barrels of oil equivalent (boe) may be misleading, particularly if used in isolation. This conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. References to "Suncor", "we", "us", "our" or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships and joint venture investments, unless the context otherwise requires. Suncor has provided cost estimates for projects that, in some cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amount is expected to differ and the difference could be material.

FINANCIAL HIGHLIGHTS









Other Key Indicators

Year ended December 31 ($ millions)	**2009**	2008	2007	2006	2005
Financial					
Revenues (net of royalties)	**25 480**	28 637	17 314	14 976	10 768
Capital and exploration expenditures	**4 246**	7 987	5 629	3 693	3 230
Total assets	**69 746**	32 528	24 509	18 959	15 335
Dollars per Common Share					
Net earnings attributable to common shareholders – basic	**0.96**	2.29	3.23	3.23	1.37
Net earnings attributable to common shareholders – diluted	**0.95**	2.26	3.17	3.16	1.35
Cash flow from operations	**2.34**	4.36	4.38	4.95	2.88
Cash dividends	**0.30**	0.20	0.19	0.15	0.12
Market Price of Common Stock at December 31 (Closing)					
Toronto Stock Exchange (Cdn$)	**37.21**	23.72	53.96	45.90	36.66
New York Stock Exchange (US$)	**35.31**	19.50	54.37	39.46	31.57
Key Ratios					
Total debt to total debt plus shareholders' equity (%)	**28.9**	35.2	24.3	20.7	33.3
Net debt to cash flow from operations (times)(4)	**4.8**	1.8	0.8	0.4	1.1
Return on shareholders' equity (%)	**5.1**	16.2	28.4	39.0	22.7

The financial highlights include the results of post-merger Suncor from August 1, 2009. As such, the amounts reflect results of the post-merger Suncor from August 1, 2009 together with results of legacy Suncor only from January 1, 2009 through July 31, 2009. The comparative figures reflect solely the results of legacy Suncor.

(1) Non-GAAP measures. See pages 52 and 53.

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

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

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

(5) The increase in capital employed as a result of the merger with Petro-Canada has caused our return on capital employed measure to decrease significantly, as the calculation only includes five months of results relating to legacy Petro-Canada operations.

MESSAGE TO SHAREHOLDERS

In many ways, each of the 42 years since Suncor Energy launched the oil sands industry represents a milestone. But there were few as pivotal as 2009. We started the year confronting one of the most challenging global economic downturns of the past century. Commodity prices collapsed while the cost of accessing capital soared. Like almost everyone else, Suncor's initial response was to retrench. We put most of our growth projects on hold and significantly reduced capital spending. But it wasn't long before we looked for ways to turn adversity into opportunity. The result was a historic merger with another proud Canadian company, Petro-Canada, to create Canada's largest independent energy company – a true global competitor for the 21st Century.

Today, Suncor is a larger, stronger and more financially flexible company. Our high-quality assets and integrated strategy provide us with a degree of protection from the volatility of commodity markets and put us in a strong position to achieve prudent, but substantial growth. In short, we have far more control over our own destiny.

But as much as 2009 marked an exciting new chapter in our company's history, it's just as important to note what *hasn't* changed. The new Suncor, like the old Suncor, is strategically focused on responsibly developing Canada's oil sands – the world's second largest petroleum resource base.

Suncor is the oil sands pioneer and, as a result of the recent merger, we now hold the largest single position in our industry. We intend to remain a leader in every aspect of the business, including production growth, technological innovation and environmental stewardship.

We also remain squarely focused on achieving safe, reliable and cost-effective energy production across all of our operations. Although we stumbled on this goal at the end of last year and early 2010 with operational upsets at our oil sands operations, the trend through the balance of 2009 was positive – and we intend to get back on track.

Breaking with the Pack

Perhaps the question I faced most often in 2009 was: why did Suncor decide, during one of the most turbulent years in recent memory, to step out with an ambitious and game-changing merger when so many others opted to seek shelter and wait out the economic storm?

My answer is that part of being a pioneer is having a long-term vision that lets you look beyond the immediate challenges of the day to chart a positive course forward. It also means that, when the pack is headed one way, you might want to glance in the other direction to see what opportunities exist for tomorrow.

We saw our merger with Petro-Canada as a unique opportunity to create a flagship Canadian-based corporation with the asset base and financial strength to compete against the global energy super-majors. Like them, we would have the ability to invest and grow through the commodity cycle.

The merger resulted in an integrated energy company that combined a leading position in the oil sands with complementary operations in refining and marketing, North American natural gas production and lower-cost oil and gas production internationally and offshore East Coast Canada. It meant a stronger balance sheet, more robust cash flow from operations and the capacity to strategically invest in a large suite of growth options.

Following the announcement of the proposed merger in March, we moved quickly to secure shareholder approval in June and final approval from Canada's Competition Bureau in July. The fast-paced consolidation of the two companies continued and, by November, we had the new organization substantially in place and were able to announce our initial growth plans for 2010 and beyond.

Bringing these two great companies together was a challenging, but rewarding, task. By far, the most difficult decisions concerned the loss of approximately 1,000 employees as we dealt with areas of operational overlap. But we did so with the knowledge that, over the long term, the merger means Suncor will be a strong contributor to job creation as we grow in ways that would not have been possible on a stand-alone basis.

When we announced the merger, we projected annual capital efficiencies of $1 billion from reduced overhead, shared infrastructure and technologies and by targeting high-return, near-term projects. Operating savings, including product and supply chain optimization and workforce rationalization, were targeted at approximately $300 million per year. By the end of 2009, we confirmed our capital efficiencies target and increased our expected operating savings to $400 million per

year, a benefit that we expect to see reflected in our earnings and cash flow from operations by the end of 2010, as our annual savings begin to exceed one-time merger costs. It was yet another sign that the merger made compelling economic sense – for Suncor's shareholders and for the long-term prosperity of our company and our industry.

Looking Ahead: Operational Excellence and Disciplined Growth

If 2009 was about moving quickly to get the merger done, 2010 will be about demonstrating the benefits.

In November 2009, Suncor's Board of Directors approved a $5.5 billion capital spending plan for 2010 that officially restarted our growth in the oil sands industry. While $4 billion was targeted at sustaining existing operations, approximately $1.5 billion was directed to new production growth, primarily at the company's oil sands operations.

Most of the growth spending is dedicated to the Firebag Stage 3 in-situ oil sands expansion, now expected to commence production in the second quarter of 2011. Some early capital support is also being directed to Firebag Stage 4, now targeted to begin production in the fourth quarter of 2012. Together, the two projects are expected to boost our production capacity by approximately 136,000 barrels per day.

These are the first steps in our strategic plan to steadily increase oil sands production, supported by cash flow from Suncor's existing operations.

We continue to review all of our potential growth projects to determine when and in which order to proceed and we expect to have a more detailed plan in place towards the end of 2010.

At the same time, Suncor is in the process of selling assets that don't support our long-term strategy. The proposed divestments identified to date include certain natural gas assets in Western Canada and the United States Rockies, all Trinidad and Tobago assets and non-core North Sea assets, including all of our assets in the Netherlands.

While we are flexible around the timing of our divestitures, we expect to complete most sales by the end of the year. The proceeds of these sales, expected to be between $2 billion and $4 billion, are planned to go towards reducing the company's debt.

The combination of strategic *investment* in oil sands growth projects and strategic *divestment* of non-core assets will mean a steady shift in favour of what has always been Suncor's core business. Currently, about 50% of Suncor's cash flow from operations is generated by oil sands; when Firebag Stage 4 comes fully on stream, we expect that figure to be closer to 65%.

As we move forward, Suncor enjoys the luxury of having more growth opportunities than we can immediately execute. So it's really a matter of ranking these opportunities and making sure we proceed with the right project at the right time in the right way.

I've been very clear about the criteria Suncor will use to determine the timing of these projects. It's about achieving the best near-term cash flow and return on capital while minimizing overall risk. It's also about realizing an even stronger balance sheet as we reduce our debt and target a net debt to cash flow from operations ratio of approximately two to one.

What our company has embarked on is a period of disciplined, but significant growth. I believe Suncor can expand its oil sands production by 10% to 12% per year over the next decade in ways that maximize the benefits for our shareholders and the larger economy without contributing to the kind of super-inflationary climate we saw during parts of the past decade.

Another aspect of discipline is ensuring our existing operations continue to perform safely, reliably and in a cost-effective manner. Operational excellence in an organization as large as Suncor isn't about doing one thing right one time – it's about doing thousands of things right all the time. It requires rigorous management, constant oversight and a talented workforce dedicated to continuous improvement.

We have been implementing an operational excellence program over the past three years across the entire company. At our oil sands operations, indicators such as improved reliability, better execution of planned maintenance and other performance measures have shown that we are making progress. The operational upsets we experienced at our oil sands upgrading operations in December 2009 and early February 2010 are a reminder that we have more work to do. Be assured we have not taken these events lightly, and are in the process of a complete review of these incidents, utilizing both internal resources as well as external experts. From the Board of Directors and executive team through to front-line operators – and supported by external experts – there is a strong commitment to deliver on reliability and personal and process safety.

It's impossible to overstate the importance of achieving excellence across our day-to-day operations. This creates the value on which we build the future. For our investors – and for all stakeholders – how we perform today determines their level of confidence in how we will perform tomorrow.

Responsible Development

The new Suncor, like the old Suncor, is committed to a set of goals and values that guide our business decisions. Central to this is the principle of a triple bottom line, which means managing our operations and growth plans in a way that enhances social and economic benefits while striving to minimize the environmental impact associated with development.

This principle is reflected in our 2010 capital spending plan, which includes a $450 million investment to begin commercial implementation of new tailings and reclamation technologies that we believe represent a significant step forward in addressing one of the biggest environmental challenges facing our industry.

Liquid tailings – the water, sand clay and residual hydrocarbons that remain after bitumen is extracted from oil sands – represent a significant economic burden for the oil sands industry. In Suncor's case, our tailings ponds account for nearly 30% of the disturbed land Suncor is currently working to reclaim. Monitoring and responsibly managing these ponds costs millions of dollars annually. Getting to a dry surface and beginning reclamation to a natural habitat more quickly is good for the environment *and* our bottom line. It's a classic example of the link between economic and environmental performance.

As the recent negotiations in Copenhagen again demonstrated, the climate change challenge means our industry must prepare for the uncertainties of how various levels of government are going to handle carbon emissions. Suncor recognized this reality nearly two decades ago when we became one of the first major energy companies to adopt a climate change action plan and developed technologies to reduce greenhouse gas emission intensity. We also made industry-leading investments in renewable energy products, an area of our business we continue to expand.

Does more need to be done? Absolutely. Suncor is committed to doing its part to help Canada meet the challenge. At the same time, our company – and the entire oil sands industry – needs to do more to inform the public about ongoing efforts to better manage greenhouse gas emissions and other environmental challenges, including water use, land disturbance and other air emissions.

None of this absolves us of the duty to act. We must – and we will – work to continuously improve our environmental performance. The new Suncor represents the joining of two progressive energy companies with a record of innovation and a willingness to engage, rather than merely confront, industry critics. We believe no one has a monopoly on good ideas and we will work with anyone who has constructive proposals to better develop this legacy resource.

A Century of Opportunity

One of the most exciting aspects of Suncor's core business is that it's not about energy production for the next five years or even 50 years, but for a century and beyond. If we do things right, we have the opportunity to set a course that will benefit generations to come.

Of the 27 billion barrels of oil equivalent in Suncor's remaining recoverable resource base, approximately 23 billion barrels come from the oil sands. We have the remarkable opportunity to map out decades of development without the need for any further exploration.

While our resource base is massive, Suncor's approach to development has always been measured. We pioneered what has become an industry model for integrated planning in which crude production, upgrading, refining and marketing operations are all connected to a single strategy, with each component complementing the other. The recent merger enhances this time-tested strategy, providing us with an even stronger set of assets that are valuable in their own right and will also play an important supporting role as we develop our core resource.

As we move forward, we will continue to benefit from the expertise of Suncor's employees – a talented team of professionals who are always up to the next challenge. I also remain indebted to Suncor's Board of Directors, who oversee all aspects of governance and are outstanding stewards of stakeholders' interests. They excel at challenging management to lead and innovate – and I want to recognize them for their guidance and support.

Together, I'm confident we'll make this next chapter in Suncor's history the most rewarding and exciting yet. We've got the resources, the capital foundation, the people and the plan. We know we have substantial work ahead of us to meet the expectations of our shareholders and others with stake in our business. We are ready for the challenge. I feel privileged to be part of this collective effort and, on behalf of Suncor's employees, management and your Board of Directors, I thank you for your continued support.

Rick George
president and chief executive officer

OUR SCORECARD

Long-term performance

- **Value at December 31, 2009 of $100 invested in Suncor on March 18, 1992 when the company became publicly traded: $4,970.** Value at December 31, 2009 of $100 invested in the S&P 500 on March 18, 1992: $341[1]
- **Greenhouse gas intensity (per unit of production) at our oil sands business in 2008 compared to 1990**: 44% reduction
- **Total water use at our oil sands business in 2008 compared to 2002**[2]: Approximately 30% absolute reduction.
- **Strategic environmental performance goals by 2015**[3]: Reduce total water intake by 12%, increase land area reclaimed by 100%, improve energy efficiency by 10% and reduce current air emissions by 10%.

2009 – Our goals and how we delivered

- **Achieve annual oil sands production of 300,000 bpd (+5%/−10%) at a cash operating cost average of $33 to $38 per barrel.** Improved operational reliability in 2009 contributed to an annual oil sands production of 290,600 bpd, and corresponding cash operating costs of $33.95 per barrel.
- **Target production from our natural gas business of 210 mmcf equivalent per day (+5%/−5%).** Production from legacy Suncor's natural gas operations was on target with an average of 210 mmcf equivalent per day in 2009.
- **Continue to focus on safety.** Suncor saw a continued decrease in Reportable Injury Frequency and Lost Time Injury Frequency, two key metrics of safety performance.
- **Maintain a strong balance sheet.** Planned capital spending was reduced to $3 billion for 2009 with major growth capital investment deferred. The merger with Petro-Canada resulted in a stronger balance sheet, more robust cash flow and the capacity to strategically invest in a large suit of growth options through the commodity cycle.
- **Continue efforts to reduce environmental impact intensity.** We completed the sulphur recovery plant at Firebag during the third quarter of 2009 and continued developing accelerated reclamation technologies which hold the potential to significantly increase the speed of reclamation.

2010 – Our targets and how we will get there

- **Operational excellence.** Focusing on operational excellence to enhance personal and process safety management, environmental excellence and sustainability, reliability, and people. Planned maintenance shutdowns are expected to improve efficiency and reliability at oil sands and refining operations.
- **Continue efforts to reduce environmental impact intensity.** We expect to reclaim the industry's first tailings pond to a trafficable surface in 2010. As well, work will continue on developing and implementing accelerated reclamation technology.
- **Strengthen balance sheet and maintain investment grade debt rating.** Planned capital spending has been set at $5.5 billion for 2010, with expected near-term cash flow from operations as key criteria for investment. Applying proceeds from planned divestitures to reduce net debt expected to contribute to a target of two-times cash flow from operations.

(1) Assuming reinvestment of dividends.

(2) 2002 is the first full-year of production following a major expansion of oil sands operations.

(3) The base year for planned improvements is 2007. All the proposed reductions are absolute except for energy efficiency which is intensity based.

This scorecard should be read in conjunction with Suncor's 2009 Management's Discussion and Analysis and audited Consolidated Financial Statements and the accompanying notes.

MANAGEMENT'S DISCUSSION AND ANALYSIS

February 26, 2010

This Management's Discussion and Analysis (MD&A) contains forward-looking information based on Suncor's current expectations, estimates, projections and assumptions. This information is subject to a number of risks and uncertainties, including those discussed in this MD&A and Suncor's other disclosure documents, many of which are beyond the company's control. Users of this information are cautioned that actual results may differ materially. For information on material risk factors and assumptions underlying our forward-looking information, see page 54.

This MD&A should be read in conjunction with Suncor's December 31, 2009 audited Consolidated Financial Statements and the accompanying notes. All financial information is reported in Canadian dollars (Cdn$) and in accordance with Canadian generally accepted accounting principles (GAAP), unless noted otherwise. The financial measures operating earnings, cash flow from operations, return on capital employed (ROCE) and cash and total operating costs per barrel referred to in this MD&A are not prescribed by GAAP and are discussed in Non-GAAP Financial Measures on page 52 and 53.

In order to provide shareholders with full disclosure relating to potential future capital expenditures, we have provided cost estimates for projects that, in some cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amounts are expected to differ and these differences may be material. For a further discussion of our significant capital projects, see the Significant Capital Project Update on page 15.

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

On August 1, 2009, Suncor completed its merger with Petro-Canada. All closing conditions were satisfied, including approvals from shareholders, the Alberta Court of Queen's Bench, and the Competition Bureau of Canada. Under the terms of the merger, Petro-Canada shareholders received 1.28 Suncor common shares for each Petro-Canada common share held. For further information with respect to the merger transaction, please refer to note 2 of the December 31, 2009 audited Consolidated Financial Statements and the accompanying notes.

The consolidated financial statements include the results of post-merger Suncor from August 1, 2009. As such, amounts disclosed in this MD&A reflect results of the post-merger Suncor from August 1, 2009 together with results of legacy Suncor only from January 1, 2009 through July 31, 2009. The comparative figures from 2008 and 2007 reflect solely the results of legacy Suncor.

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

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

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

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

SUNCOR OVERVIEW AND STRATEGIC PRIORITIES

Suncor Energy Inc. is an integrated energy company headquartered in Calgary, Alberta. We operate five businesses:

- **Oil Sands**, located near Fort McMurray, Alberta, produces bitumen recovered from oil sands through mining and in-situ technology and upgrades it into refinery feedstock, diesel fuel and by-products. The company has a 12% ownership interest in the Syncrude oil sands mining and upgrading joint venture, also located near Fort McMurray, Alberta.
- **Natural Gas**, located primarily in Western Canada, explores for, acquires, develops and produces natural gas, natural gas liquids and crude oil. The sale of natural gas production offsets Suncor's purchases for internal consumption at our North American operations. Suncor is currently divesting certain non-core assets as we focus the strategy of this business.
- **East Coast Canada**, comprised of oil development activity offshore of Newfoundland and Labrador. The company has a strong position in every major oil development off Canada's east coast, including Hibernia, White Rose, Terra Nova and Hebron.
- **International**, which includes activities in key core areas such as the North Sea (including the United Kingdom, the Netherlands and Norway sectors), Libya, Syria, and offshore Trinidad and Tobago. Suncor is currently divesting certain non-core assets as we focus the strategy of this business.
- **Refining and Marketing**, includes refineries located in Alberta, Quebec, Ontario and Colorado, which produce and market the company's refined products to retail, commercial and industrial customers. Refining and Marketing also owns and operates a lubricants business in Ontario, which manufactures, blends and markets high quality products world-wide, interests in pipelines and terminals, and a network of retail service stations across Canada and the state of Colorado.

In addition, the company engages in third-party energy marketing and trading activities, and has investments in renewable energy opportunities, including Canada's largest ethanol plant by volume and partnerships in four wind power projects.

Suncor's strategic priorities are:

- Maintaining financial strength and flexibility through disciplined cost, capital and debt management, and stewardship of the balance sheet.
- Increasing our return on capital employed through targeting capital budgets to high-return, near-term projects.
- Focusing on plant and process reliability, efficiency and cost management as part of operational excellence initiatives.
- Developing our oil sands resource base through mining and in-situ technology and supplementing our bitumen production with third-party supply.
- Expanding oil sands mining, in-situ and upgrading facilities to increase crude oil production and improving reliability by providing flexible bitumen feed and upgrading options.
- Integrating oil sands production into the North American energy market through Suncor's refineries and third-party refineries to reduce vulnerability to supply and demand imbalances.
- Focusing on our East Coast Canada and International assets, which provide steady low-cost cash flows and offer stability during low commodity cycles to support our core oil sands operations.
- Reducing risk associated with commodity price volatility by producing natural gas volumes that offset purchases for internal consumption.
- Advancing environmental and social performance by closely managing impact to air, water and land while also earning continued stakeholder support for our ongoing operations and growth plans.
- Maintaining a strong focus on employee, contractor and community health and safety.

2009 Overview

Key milestones and developments over the course of 2009 and early 2010 included:

Challenging economic environment to start the year. Low benchmark commodity prices significantly impacted earnings. We took action to protect our future revenues by entering into derivative contracts. As prices recovered later in 2009, we realized large losses as the settlement prices were lower than benchmark prices.

Capital spending plans were reduced. As cash flows were reduced, and the credit markets dried up, Suncor revised its spending plans down to $3 billion, and deferred a number of capital projects. Costs related to keeping these projects in "safe mode" totalled approximately $380 million in 2009.

Completed a merger with Petro-Canada on August 1, 2009. This resulted in Suncor becoming Canada's largest energy company by market capitalization, and provided Suncor with a number of key benefits:

- **Steady production from established assets in East Coast Canada and International that will support Suncor's growth through the commodity cycle.** Total production volumes from these two segments averaged approximately 178,000 bpd over the last five months of 2009.
- **Additional refining capacity provides options for expanding oil sands production.** Increased refining capacity from 178,000 bpd to 433,000 bpd. Observed performance improvements at our Edmonton refinery have enabled us to upwardly revise our nameplate capacity to 443,000 bpd. Sales of refined petroleum products during the final five months of 2009 averaged 84.8 million litres per day.
- **Solid hedge for natural gas usage at our North American operations.** Total production from our Natural Gas business segment averaged 677 mmcfe/d for the final five months of the year.
- **Synergy opportunities**[(1)]. Operating synergies of approximately $400 million on an annualized basis have been identified. We expect that synergies will start to exceed merger and integration costs by the end of 2010, when we start realizing the full benefits of the merger. We also expect to achieve annual capital efficiencies of approximately $1 billion through elimination of redundant spending and targeting capital budgets to high-return, near-term projects.

Improved Oil Sands operational reliability. Annual production from our Oil Sands business segment averaged 290,600 bpd in 2009, compared to 228,000 bpd in 2008, with record production in November and cash operating costs (excluding Syncrude) averaging $33.95 per barrel during 2009, compared to $38.50 per barrel in 2008. However, fires in our Oil Sands operations in December 2009 and February 2010 have negatively impacted volumes.

Growth capital restarts. In November, Suncor announced 2010 capital spending plans that included restarting construction of our Firebag Stage 3 in-situ oil sands project.

Planned divestments. As part of its strategic business alignment, Suncor began the process of divesting a number of non-core natural gas assets, all Trinidad and Tobago assets and certain non-core North Sea assets, including all assets in The Netherlands. Announced sales to date include substantially all of our oil and gas producing assets in the U.S. Rockies, non-core natural gas properties in Northeast British Columbia, and all Trinidad and Tobago assets. The effective close date of the U.S. Rockies sale was March 1, 2010. The other sales are expected to close in the first quarter of 2010 and are subject to customary closing conditions and regulatory approvals. The proceeds of these sales, expected to be between $2 billion and $4 billion, are planned to go towards reducing the company's debt. Net debt at year-end 2009 was $13.4 billion.

(1) Synergy estimates are based on certain assumptions that management currently believes are reasonable, including but not limited to: reduced operating costs due to restructuring synergies, acceleration of timing of planned capital projects and resulting revenues, reduced capital costs relating to divested assets and cash flow from divested assets. Please see Legal Notice – Forward-Looking Information on page 54.

SELECTED FINANCIAL INFORMATION

Annual Financial Data

Year ended December 31 ($ millions except per share)	**2009**	2008	2007
Revenue (net of royalties)	**25 480**	28 637	17 314
Net earnings	**1 146**	2 137	2 983
Total assets	**69 746**	32 528	24 509
Long-term debt	**13 880**	7 884	3 814
Dividends on common shares	**401**	180	162
Net earnings attributable to common shareholders per share – basic	**0.96**	2.29	3.23
Net earnings attributable to common shareholders per share – diluted	**0.95**	2.26	3.17
Cash dividends per share	**0.30**	0.20	0.19

Outstanding Share Data

At December 31, 2009 (thousands)	
Number of common shares	1 559 778
Number of common share options	72 024
Number of common share options – exercisable	42 755

Industry Indicators

(Average for the year)	**2009**	2008	2007
West Texas Intermediate (WTI) crude oil US$/barrel at Cushing	**61.80**	99.65	72.30
Dated Brent crude oil US$/barrel at Sullom Voe	**61.50**	97.00	72.50
Dated Brent/Maya FOB price differential US$/barrel	**5.00**	13.15	12.65
Canadian 0.3% par crude oil Cdn$/barrel at Edmonton	**65.80**	103.05	76.65
Edmonton Light/Western Canadian Select price differential Cdn$/barrel	**6.65**	19.90	24.05
Light/heavy crude oil differential US$/barrel WTI at Cushing less Western Canadian Select at Hardisty	**9.70**	20.10	22.25
Natural gas US$/thousand cubic feet (mcf) at Henry Hub	**4.00**	8.95	6.90
Natural gas (Alberta spot) Cdn$/mcf at AECO	**4.15**	8.15	6.60
New York Harbour 3-2-1 crack (1) US$/barrel	**7.80**	9.10	13.70
Chicago 3-2-1 crack (1) US$/barrel	**7.75**	10.40	16.85
Seattle 3-2-1 crack (1) US$/barrel	**11.40**	11.80	19.55
Gulf Coast 3-2-1 (1) US$/barrel	**7.10**	9.45	13.30
Exchange rate: US$/Cdn$	**0.88**	0.94	0.93

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

On August 1, 2009, Suncor Energy Inc. completed its merger with Petro-Canada. The amounts ending December 31, 2009 reflect results of the post-merger Suncor from August 1, 2009 together with results of legacy Suncor only from January 1 through July 31, 2009. The comparative figures reflect solely the 2008 and 2007 results of legacy Suncor. For further information with respect to the merger transaction, please refer to note 2 of the December 31, 2009 audited Consolidated Financial Statements and the accompanying notes.

CONSOLIDATED FINANCIAL ANALYSIS

This analysis provides an overview of our consolidated financial results for 2009 compared to 2008. For a detailed analysis, see the various business segment discussions.

Net Earnings

Our net earnings were $1.146 billion in 2009, compared with $2.137 billion in 2008 (2007 – $2.983 billion). The decrease in net earnings is due primarily to lower price realizations, as average benchmark commodity prices were significantly weaker in 2009 compared to 2008, losses on commodity derivatives used for risk management compared to gains in the prior year, and costs incurred related to placing certain growth projects into safe mode due to market conditions earlier in the year.

These factors were partially offset by higher production from our existing oil sands assets resulting from improved operational performance, upstream production and refined product sales volumes resulting from the merger with Petro-Canada, unrealized foreign exchange gains on our U.S. denominated long-term debt due to the stronger Canadian dollar and a gain from the deemed settlement of the bitumen processing contract with Petro-Canada upon close of the merger (See note 2(e) to the December 31, 2009 audited Consolidated Financial Statements).

Revenues were $25.480 billion in 2009, compared with $28.637 billion in 2008 (2007 – $17.314 billion). The decrease was primarily due to the following factors:

- Operating revenues were adversely impacted by significantly weaker benchmark prices in 2009. In addition, losses on commodity price risk derivatives which we had initiated when commodity prices hit a low point early in 2009, also negatively affected operating revenues as prices recovered later in the year.
- Royalties increased to $1.199 billion in 2009 from $890 million in 2008, due primarily to royalty expense on additional production resulting from the merger with Petro-Canada, as well as increased production in legacy Suncor's oil sands operations. This was partially offset by lower commodity prices. For a discussion of Crown royalties, see pages 16 to 18.
- Energy trading revenues decreased to $7.577 billion in 2009, compared to $11.320 billion in 2008. Lower trading revenues partly resulted from decreased commodity prices. In addition, after the merger with Petro-Canada, we determined that certain physical trading commodity contracts exceeded the company's expected purchase, sale or usage requirements, and effective October 1, 2009, gains and losses on these contracts have been reported on a net basis. Had we continued reporting on a gross basis, energy supply and trading revenues would have been approximately $2 billion larger in 2009.

Partially offsetting these decreases were the following:

- Total upstream production and sales volumes were higher during 2009, mainly as a result of the merger with Petro-Canada, as well as improved reliability in legacy Suncor's oil sands operations. After completion of the merger with Petro-Canada, Suncor's total upstream production during the final five months of 2009 averaged 635,200 boe per day. Upstream production from legacy Suncor's oil sands and natural gas operations averaged 325,600 boe per day in 2009, compared to 264,700 boe per day in 2008.
- Other income included a $438 million gain related to the effective settlement of a pre-existing bitumen processing contract with Petro-Canada. For further details on this one-time item, see note 2(e) to the Consolidated Financial Statements on page 73.
- Stronger price realizations for sales of our oil sands sweet blend and diesel product relative to WTI positively impacted operating revenue.

The cost to purchase crude oil and crude oil products was $7.383 billion in 2009, compared to $7.582 billion in 2008 (2007 – $6.414 billion). The decrease was primarily due to the following:

- Lower benchmark crude oil prices. This had the largest impact on product purchases for our Refining and Marketing business, as average WTI prices were approximately 38% lower than in 2008.
- Decreased purchases of third-party product in our Oil Sands segment, primarily due to a reduction of planned and unplanned shutdowns, as 2008 results reflected higher purchases of diesel and bitumen to meet customer commitments. In addition, in 2008 Suncor purchased larger volumes of product from third parties to upgrade at Suncor facilities.

Partially offsetting these decreases was the following:

- Increased purchases in our Refining and Marketing segment due to the addition of refining assets as a result of the merger with Petro-Canada.

Operating, selling and general expenses were $6.641 billion in 2009 compared with $4.186 billion in 2008 (2007 – $3.450 billion). The primary reasons for the increase were:

- The addition of Petro-Canada operations and the related operating, selling and general expenses; and higher production and sales volumes in legacy Suncor operations.
- Higher planned maintenance expenditures at our oil sands operations related to the implementation of reliability and operational efficiency initiatives.
- Incurred costs related to placing our growth projects into safe mode as a result of the company revising its 2009 capital budget due to market conditions earlier in the year.
- One-time costs related to a number of merger and integration activities.

Partially offsetting these increases was the following:

- Decreased energy input costs, resulting mainly from significantly lower natural gas prices. The average benchmark AECO price in 2009 was down almost 50% compared to 2008.

Transportation costs were $427 million in 2009, compared to $246 million in 2008 (2007 – $160 million). The increase in transportation costs was primarily due to the additional production and sales volumes as a result of the merger with Petro-Canada.

Depreciation, depletion and amortization (DD&A) was $2.306 billion in 2009, compared to $1.049 billion in 2008 (2007 – $864 million). The increase primarily reflects the addition of assets as a result of the merger.

Financing income was $487 million in 2009, compared with expense of $917 million in 2008 (2007 – income of $211 million). The decrease in financing expense was primarily due to foreign exchange gains on our U.S. dollar denominated long-term debt in 2009, compared to losses in 2008. This was partially offset by additional debt acquired through the merger with Petro-Canada, and by interest costs that were not capitalized during 2009 as a number of growth projects were in safe mode during the period.

Income tax expense was $143 million in 2009 (11% effective tax rate), compared to $995 million in 2008 (32% effective tax rate) and $566 million in 2007 (16% effective tax rate). The lower effective tax rate for 2009 compared to 2008 is primarily a result of foreign exchange gains on our U.S. dollar denominated long-term debt being taxed at a lower capital gains rate, no tax assessed on the gain on effective settlement of the pre-existing contract with Petro-Canada, and tax filing reconciliations.

Cash Flow from Operations

Cash flow from operations was $2.799 billion in 2009, compared to $4.057 billion in 2008 (2007 – $4.037 billion). The decrease in cash flow from operations was primarily due to the same factors that impacted earnings. Cash flow from operations is a non-GAAP measure that the company uses to evaluate operating performance. See page 52 and 53 for discussion of non-GAAP financial measures.

Dividends

Total dividends paid during 2009 were $0.30 per share, compared with $0.20 per share in 2008 (2007 – $0.19 per share). Suncor's Board of Directors periodically reviews the dividend policy, taking into consideration the company's capital spending profile, financial position, financing requirements, cash flow and other relevant factors.

Quarterly Financial Data

	2009				2008			
	Three months ended				Three months ended			
($ millions except per share)	**Dec 31**	**Sept 30**	**June 30**	**Mar 31**	Dec 31	Sept 30	June 30	Mar 31
Revenues (net of royalties)	**7 636**	**8 443**	**4 768**	**4 633**	6 952	8 507	7 640	5 539
Net earnings (loss)	**457**	**929**	**(51)**	**(189)**	(215)	815	829	708
Net earnings (loss) attributable to common shareholders per share								
Basic	**0.29**	**0.69**	**(0.06)**	**(0.20)**	(0.24)	0.87	0.89	0.77
Diluted	**0.29**	**0.68**	**(0.06)**	**(0.20)**	(0.24)	0.86	0.87	0.75

Variations in quarterly net earnings (loss) during 2009 and 2008 were due to a number of factors:

- Additional upstream production and refined product sales volumes resulting from the merger with Petro-Canada, impacting the third and fourth quarter of 2009.
- Changes in benchmark commodity prices throughout 2009 and 2008. WTI averaged US$61.80 per barrel (bbl) in 2009, compared to US$99.65/bbl in 2008, while AECO averaged Cdn$4.15/mcf in 2009, compared to Cdn$8.15/mcf in 2008.
- Oil sands production and sales volumes decreased during periods of planned and unplanned maintenance.
- Cash operating costs varied due to changes in oil sands production levels, the timing and amount of maintenance activities, and the price and volume of natural gas used for energy in oil sands operations.
- Exchange rate fluctuations impacted the realized commodity prices on our products sold in U.S. dollars, affecting the Canadian dollar revenues earned. Changes in the exchange rate also led to unrealized gains/losses on our U.S. dollar denominated long-term debt.
- Crown royalties varied as a result of changes in commodity prices, changes in production and the extent and timing of eligible capital and operating expenditures.
- Refined product prices fluctuated as a result of global and regional supply and demand, as well as seasonal demand variations.
- Improved reliability in legacy Suncor's refineries, resulting in increased refined product sales and margins.

For further analysis of quarterly results, refer to Suncor's quarterly reports to shareholders available on our website.

Operating Earnings

Operating earnings is a non-GAAP measure that the company uses to evaluate operating performance, which management believes allows better comparability between periods. Operating earnings is calculated by adjusting net earnings for significant one-time items and items that are not indicative of operating performance. See page 52 for a discussion of non-GAAP financial measures.

Year ended December 31 ($ millions, after-tax)	**2009**	2008	2007
Net earnings as reported	**1 146**	2 137	2 983
Change in fair value of commodity derivatives used for risk management	**499**	(372)	—
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(798)**	852	(215)
Mark-to-market valuation of stock-based compensation	**124**	(107)	35
Project start-up costs	**40**	24	49
Impact of income tax rate adjustments on future income tax liabilities (1)	**4**	—	(427)
Costs related to deferral of growth	**300**	—	—
Gain on effective settlement of pre-existing contract with Petro-Canada (2)	**(438)**	—	—
Impact of recording acquired inventory at fair value (3)	**97**	—	—
Merger and integration costs	**151**	—	—
Losses and adjustments on significant disposals (4)	**81**	—	—
Operating earnings	**1 206**	2 534	2 425

(1) In the third quarter of 2009, a $152 million increase in the future income tax liabilities resulted from a revised provincial allocation for income tax purposes due to the merger with Petro-Canada. This was partially offset for the year ended December 31, 2009 by a reduction to the Ontario income tax rate in the fourth quarter of 2009, resulting in a $148 million decrease in the future income tax liabilities. See note 7 to the Consolidated Financial Statements.

(2) Impact from deemed settlement value assigned to bitumen processing contract with Petro-Canada upon close of merger. See note 2 to the Consolidated Financial Statements.

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

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

Operating earnings were $1.206 billion in 2009, compared to $2.534 billion in 2008 (2007 – $2.425 billion). The decrease in operating earnings is due primarily to lower price realizations, as average benchmark commodity prices were significantly weaker in 2009 compared to 2008. In addition, we realized losses on our risk management derivative contracts, as settlement prices were lower than market prices in the latter part of 2009 as commodity prices improved. These factors were partially offset by the increased upstream production and refined product sales volumes resulting from the merger with Petro-Canada, and improved operational performance from our existing oil sands assets.

LIQUIDITY AND CAPITAL RESOURCES

Our capital resources consist primarily of cash flow from operations and available lines of credit. As a result of the merger with Petro-Canada, we added approximately $4.2 billion in unutilized credit facilities and $415 million in cash.

We believe we will have the capital resources to fund our planned capital spending program and to meet current working capital requirements through cash flow from operations and our committed credit facilities, assuming our current production outlook and other business plan assumptions are met. Our cash flow from operations depends on a number of factors, including commodity prices, production/sales levels, refining and marketing margins, operating expenses, taxes, royalties, and foreign exchange rates. If additional capital is required, we believe adequate additional financing will be available in the debt capital markets at commercial terms and rates. Our spending is subject to change due to factors such as internal and regulatory approvals and capital availability. Refer to the discussion under Risk Factors Affecting Performance on page 20 for additional factors that may have an impact on our ability to fund our capital requirements.

To significantly reduce current debt levels in 2010, the company is targeting to apply the proceeds from the announced divestment program. The expected proceeds of $2 billion to $4 billion will be used to repay debt as the transactions are completed, subject to the financial and operational factors outlined previously, as internally generated cash flow will be used to fund our capital program.

Financing Activities

Management of debt levels continues to be a priority given our long-term growth plans. We believe a phased and flexible approach to existing and future growth projects should assist us in maintaining our ability to manage project costs and debt levels.

At December 31, 2009, our net debt (short-term debt, current portion of long-term debt and long-term debt less cash and cash equivalents) was $13.377 billion, compared to $7.226 billion at December 31, 2008. The increase in debt levels was primarily a result of the debt acquired from the merger with Petro-Canada, in addition to an increase in the drawn credit facilities that supported our capital spending program. The merger also caused our net debt/cash flow from operations measure to increase significantly, as the calculation only includes five months of cash flow from operations relating to legacy Petro-Canada operations.

Interest expense on debt continues to be influenced by the composition of our debt portfolio, and we are currently benefiting from short-term floating interest rates which remain at low levels compared to historical short-term rates. To manage fixed versus floating rate exposure, we have entered into interest rate swaps with investment grade counterparties. At December 31, 2009, we had $200 million of fixed-rate to variable-rate interest swaps (December 31, 2008 – $200 million).

During the fourth quarter of 2009, we reduced our committed bilateral credit facility from $855 million to $61 million, reduced our Canadian-based demand bilateral credit facilities from $588 million to $413 million, and we increased our commercial paper program from $1.5 billion to $2.5 billion. Unutilized lines of credit at December 31, 2009 were $4.208 billion.

Excluding cash and cash equivalents, short-term debt, the current portion of long-term debt and future income taxes, Suncor had an operating working capital deficiency of $309 million at December 31, 2009, compared to a deficiency of $851 million at December 31, 2008. The reduced deficiency was primarily due to increased inventory levels as a result of the merger with Petro-Canada.

We are subject to financial and operating covenants related to our public market and bank debt. Failure to meet the terms of one or more of these covenants may constitute an Event of Default as defined in the respective debt agreements, potentially resulting in accelerated repayment of one or more of the debt obligations.

We are in compliance with our financial covenant that requires consolidated debt to not be more than 60% of our total capitalization. At December 31, 2009, our consolidated debt to total capitalization was 28.9% (where consolidated debt is short-term debt plus current portion of long-term debt plus long-term debt, and total capitalization is consolidated debt plus shareholders' equity). We are also currently in compliance with all operating covenants. In addition, a limited number of our derivative financial instrument agreements contain provisions linked to debt ratings that may result in settlement of the outstanding transactions should our debt ratings fall below investment grade status.

All of our debt ratings are currently investment grade. Suncor's current long-term senior debt ratings are BBB+, with a Stable Outlook from Standard & Poor's ("S&P"); A(low), with a Stable Trend from Dominion Bond Rating Service ("DBRS"); and Baa2, with a Stable Outlook from Moody's Investors Service. Suncor's current commercial paper ratings are A-1 (Low) from S&P and R-1 (low) from DBRS.

The preceding paragraphs contain forward-looking information regarding our liquidity and capital resources based on factors and assumptions discussed above and on page 20. Users of this information are cautioned that our actual liquidity and capital resources may vary materially from our expectations. See the discussion with respect to forward-looking information on page 54.

Aggregate Contractual Obligations

In the normal course of business, the company is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable.

		Payments Due by Period			
($ millions)	Total	2010	2011-2012 (aggregate)	2013-2014 (aggregate)	Later Years
Fixed-term debt and revolving-term debt [1]	13 586	3 244	500	742	9 100
Interest payments on fixed-term debt	12 197	651	1 255	1 219	9 072
Capital leases	711	35	68	72	536
Employee future benefits [2]	1 976	154	338	380	1 104
Asset retirement obligations [3]	8 280	318	468	352	7 142
Operating lease agreements, pipeline capacity, energy services commitments and delivery obligations [4]	12 724	1 090	1 787	1 550	8 297
Other long-term obligations [5]	1 146	382	568	139	57
Total	50 620	5 874	4 984	4 454	35 308

In addition to the enforceable and legally binding obligations quantified in the above table, we have other obligations for goods and services and raw materials entered into in the normal course of business, which may terminate on short notice. Commodity purchase obligations for which an active, highly liquid market exists, and which are expected to be re-sold shortly after purchase, are one example of excluded items.

(1) Includes $8.075 billion of U.S. and $1.800 billion of Canadian dollar denominated debt that is redeemable at our option. Maturities range from 2011 to 2039. Interest rates vary from 4.00% to 9.25%. We entered into interest rate swap transactions maturing in 2011 that resulted in an average effective interest rate in 2009 of 1.97% on $200 million of our Medium Term Notes. Approximately $3.244 billion of revolving-term debt with an effective interest rate of 0.74% was issued and outstanding at December 31, 2009.

(2) Represents the undiscounted expected funding by the company to its pension plans as well as benefit payments to retirees for other post-retirement benefits.

(3) Represents the undiscounted amount of legal obligations associated with site restoration on the retirement of assets with determinable lives.

(4) Includes annual tolls payable under transportation service agreements with major pipeline companies to use a portion of their pipeline capacity and tankage, as applicable, for transportation of product within Canada and the United States. In addition, includes commitments under long-term energy agreements to obtain a portion of the power and the steam generated by certain cogeneration facilities owned by a major third-party energy company and obligations associated with reimbursing BG Gas Marketing for gas quantities in the Trinidad LNG Sales Contract.

(5) Includes Libya Exploration and Production Sharing Agreements (EPSA) signature bonus and Fort Hills purchase obligation. See note 16 to the Consolidated Financial Statements.

Significant Capital Project Update

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

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

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

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

Suncor spent $4.2 billion on capital and exploration expenditures in 2009, compared to $8.0 billion in 2008 (2007 – $5.6 billion). A summary of the progress on our significant projects under construction to support both our growth and sustaining needs is provided below. All projects listed below have received Board of Directors approval. The estimates and target completion dates do not include project commissioning and start-up.

The company continues to incur costs related to placing certain growth projects into "safe mode" as a result of the company revising its 2009 capital budget due to market conditions earlier in the year. Safe mode is defined as the costs of deferring the projects and keeping the equipment and facilities in a safe manner in order to expedite remobilization. As a result of placing the company's projects into safe mode, pre-tax costs of $382 million were incurred in 2009. Further safe mode costs of $150 million to $200 million on a pre-tax basis, including costs related to the remobilization of growth projects placed into safe mode, are expected to be incurred in 2010.

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

(1) Cost estimates and estimate accuracy reflect budgets approved by Suncor's Board of Directors.
(2) Amounts represent Suncor's net share in the project.
(3) As a result of labour shortages and cost escalation, the cost estimate has been revised to $850 million +4/−4% (previously $650 million +10/−10%).
(4) Initial production is expected in the second quarter of 2010.

The preceding paragraphs and table contain forward-looking information and users of this information are cautioned that the actual timing, amount of the final capital expenditures and expected results, including target completion dates, for each of these projects may vary from the plans disclosed in the table. For a list of the

material risk factors that could cause actual timing, amount of the final capital expenditures and expected results to differ materially from those contained in the previous table, please see page 20. For additional information on risks, uncertainties and other factors that could cause actual results to differ, please see page 54.

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

Guarantees, Variable Interest Entities and Off-Balance Sheet Arrangements

CICA Accounting Guideline 15, *Consolidation of Variable Interest Entities* (VIEs), provides criteria for the identification of VIEs and further criteria for determining what entity, if any, should consolidate them. Entities in which equity investors do not have the characteristic of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinate financial support are subject to consolidation by a company if that company is deemed the primary beneficiary. The primary beneficiary is the party that is subject to a majority of the risk of loss from the VIE's activities, or is entitled to receive a majority of the VIE's residual returns, or both. The company has determined that certain retail licensee and wholesale marketer agreements would constitute VIEs, even though the company has no ownership in these entities. The company, however, is not the primary beneficiary and, therefore, consolidation is not required. In certain of the retail licensee arrangements, the company has provided loan guarantees. Management is of the opinion that the company's maximum exposure to loss from these arrangements would not be significant.

The company has agreed to indemnify holders of all notes and debentures and the company's credit facility lenders (see note 17 to the Consolidated Financial Statements) for added costs relating to taxes, assessments or other government charges or conditions, including any required withholding amounts. Similar indemnity terms apply to certain facility and equipment leases.

There is no limit to the maximum amount payable under the indemnification agreements described above. The company is unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, Suncor has the option to redeem or terminate these contracts if additional costs are incurred.

ROYALTIES

Oil Sands Crown Royalties

Under the Province of Alberta's generic oil sands royalty regime in effect to December 31, 2008 (1997 Generic Regime), Alberta Crown royalties for oil sands projects were payable at the rate of 25% of the difference between a project's annual gross revenues net of reasonable quality adjustments and related allowable transportation costs (R), less allowable costs (C) including allowable capital expenditures (the R – C Royalty). This is subject to a minimum royalty at 1% of revenues should allowable costs exceed revenues as determined using the R-C Royalty Formula. The Alberta government has classified Suncor's current oil sands operations as two distinct "projects" for royalty purposes.

Royalties on our Firebag in-situ project were under the 1997 Generic Regime until the end of 2008, and assessed based on bitumen value. In December 2008, the government of Alberta enacted the New Royalty Framework which increased royalty rates from the 1997 Generic Regime to a sliding scale royalty of 25% to 40% of R – C, subject to minimum royalty of 1% to 9% of R, depending on oil price. In both cases, the sliding scale royalty moves with increases in WTI prices from Cdn$55/bbl to the maximum rate at a WTI price of Cdn$120/bbl.

The MacKay River in-situ project acquired with the merger of Suncor and Petro-Canada on August 1, 2009. Mackay River is also subject to royalties based on the New Royalty Framework.

Royalties on our base oil sands mining and associated upgrading operations are modified by Crown agreements and are assessed on the R – C royalty, subject to a minimum royalty, as follows:

- Based on upgraded product values until December 31, 2008 with the rates at 25% of R – C, subject to the 1% minimum royalty of R.
- Commencing January 1, 2009, a bitumen-based royalty applied pursuant to Suncor's exercise of its option to transition to the bitumen-based 1997 Generic Regime. The royalty rates were at 25% of R – C, subject to the 1% minimum royalty of R, but applied to a revised R – C, where R was based on bitumen value and C would exclude substantially all upgrading operating and related capital costs.

- From January 1, 2010 through December 31, 2015, pursuant to our January 2008 Royalty Amending Agreement (RAA) with the government of Alberta, the New Royalty Framework rates described above will apply to the bitumen royalty for current production levels, subject to a cap of 30% of R – C, and a minimum royalty of 1% to 1.2% of R. In addition, the Suncor RAA provides Suncor with a level of certainty for various matters, including the bitumen valuation methodology, allowed costs, royalty-in-kind and certain taxes.

In 2016 and subsequent years, the royalty rates for all of our oil sands operations will be the rates prescribed under the New Royalty Framework, unless it is amended or superseded prior to that time.

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

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

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

The previous table contains forward-looking information and users of this information are cautioned that actual Crown royalty expense may vary from the percentages disclosed in the table. The percentages disclosed in the table were developed using the following assumptions: current agreements with the Government of Alberta, royalty rates and other changes enacted effective January 1, 2009 by the Government of Alberta, current forecasts of production, capital and operating costs, and the forward estimates of commodity prices and exchange rates described in the table.

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

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

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

(iii) Changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each oil sands project; changes resulting from regulatory audits of prior year filings; further changes to applicable royalty regimes

by the government of Alberta; changes in other legislation; and the occurrence of unexpected events all have the potential to have an impact on royalties payable to the Crown.

For further information on risk factors related to royalty rates, please see page 54 of Suncor's Annual Information Form dated March 5, 2010.

Syncrude Royalties

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

Alberta Natural Gas Crown Royalties

In 2008, royalty rates on natural gas production in Alberta were capped at 30% for gas discovered in 1974 or later and 35% for gas discovered prior to 1974. These rates were subject to reduction if (i) gas prices dropped below $3.70/gigajoule ($3.89/mcf), (ii) a gas well qualified for a deep gas royalty holiday incentive, or (iii) a gas well qualified as a low productivity well. The New Royalty Framework, effective from January 1, 2009, is a sliding scale that is dependent on the production rate, depth of the well, and the market price for natural gas, up to a maximum royalty rate of 50%. The framework provides some royalty relief, under the Natural Gas Deep Drilling Program, for wells drilled beyond 2,500 metres true vertical depth, based on the total depth and whether the well is exploratory or developmental. On November 19, 2008, the government of Alberta announced the Transitional Royalty Program available for wells from 1,000 metres to 3,500 metres in measured depth. Companies can elect to be subject to the Transitional Royalty Program for qualifying wells which would cap the maximum royalty at 30%, however, these wells cannot also receive royalty relief from the Natural Gas Deep Drilling Program. The Transitional Royalty Program is available from 2009 to 2013 inclusive. After January 1, 2014, all wells are subject to the New Royalty Framework.

East Coast Canada Royalties

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

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

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

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

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

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

CASH INCOME TAXES

We estimate we will have cash income taxes of approximately $800 million to $900 million during 2010. Cash income taxes are sensitive to crude oil and natural gas commodity price volatility and the timing of deductibility of capital expenditures for income tax purposes, among other things. This estimate is based on the following assumptions: current forecasts of production, capital and operating costs and the commodity prices and exchange rates described in the royalty estimate tables on page 17 and 18, assuming there are no changes to the current income tax regime. Our outlook on cash income taxes is a forward-looking

statement and users of this information are cautioned that actual cash income taxes may vary materially from our outlook.

DERIVATIVE FINANCIAL INSTRUMENTS

We periodically enter into derivative contracts such as forwards, futures, swaps, options and costless collars to hedge against the potential adverse impact of changing market prices due to changes in the underlying indices. We also use physical and financial energy derivatives to earn trading revenues.

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

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

The fair value of our derivative financial instruments at December 31, were as follows:

($ millions)	**2009**	2008
Derivative financial instruments		
Assets	**231**	660
Liabilities	**(572)**	(27)
Net derivative financial instruments	**(341)**	633

Commodity Price Risk Management Activities

The company has hedged a portion of its forecasted U.S. dollar denominated crude oil sales subject to U.S. dollar West Texas Intermediate (WTI) price risk. For the full year 2010, we hold crude oil hedges for approximately 50,000 bpd at an equivalent WTI floor price of US$50.00 per barrel and a ceiling price of approximately US$68.00 per barrel.

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

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

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

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

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

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

(3) Premium received was US$213 million.

The earnings impact associated with our commodity price risk derivatives for the twelve months ended December 31, 2009 was a net pretax loss of $1.025 billion (2008 – pretax gain of $465 million).

Energy Supply and Trading Activities

Suncor uses crude oil, natural gas and refined product derivative contracts to earn supply and trading revenues. The results of these supply and trading activities are reported as energy supply and trading revenues and expenses in the Consolidated Statements of Earnings. The net pretax loss associated with our energy trading activities in 2009 was $70 million (2008 – earnings of $127 million).

Risks Associated with Derivative Financial Instruments

Our price risk management strategies are subject to periodic management reviews to determine appropriate hedge requirements in light of our tolerance for exposure to market volatility as well as the need for stable cash flow to finance future growth.

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

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

For further details on our derivative financial instruments, including a sensitivity analysis of the effect of changes in commodity prices on our financial contracts and additional discussion of exposure to risks and our mitigation activities, see note 4 to the Consolidated Financial Statements on page 74.

RISK FACTORS AFFECTING PERFORMANCE

Our financial and operational performance is potentially affected by a number of factors including, but not limited to, commodity prices and exchange rates, environmental regulations, changes to royalty and income tax legislation, credit market conditions, stakeholder support for activities and growth plans, extreme weather, regional labour issues and other issues discussed within Risk Factors Affecting Performance for each of our business segments. A more detailed discussion of our risk factors is presented in our most recent Annual Information Form (AIF)/Form 40-F, filed with securities regulatory authorities. We are continually working to mitigate the impact of potential risks to our stakeholders. This process includes an entity-wide risk review. This internal review is completed annually to ensure all significant risks are identified and appropriately managed. Certain key risk factors are discussed below:

Integration Risk

The company completed the merger with Petro-Canada in order to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits including, cost savings and other operational synergies. Achieving the benefits of the merger depends in part on the ability of Suncor to effectively capitalize on its scale, scope and leadership position in the oil sands industry, to realize the anticipated capital and operating synergies, to profitably sequence the growth prospects of its asset base and to maximize the potential of its improved growth opportunities and capital funding opportunities as a result of combining the businesses and operations of Suncor and Petro-Canada. A variety of factors, including the required dedication of substantial management effort, time and resources on integration matters, which may divert focus and resources from other strategic opportunities of Suncor, and those other risk factors set forth in this MD&A, may adversely affect the ability to achieve the anticipated benefits of the merger.

Commodity Prices and Exchange Rates

Our future financial performance remains closely linked to hydrocarbon commodity prices, which may be influenced by many factors including global and regional supply and demand, seasonality, worldwide political events and weather. These factors can cause a high degree of price volatility. For example, from 2007 to 2009, the monthly average price for benchmark WTI crude oil ranged from a low of US$39.26/bbl to a high of US$134.02/bbl. During the same three-year period, the natural gas AECO benchmark monthly average price ranged from a low of $2.70/mcf to a high of $11.39/mcf.

Crude oil prices are based on U.S. dollar benchmarks that result in our realized prices being influenced by the US$/Cdn$ currency exchange rate, thereby creating an element of uncertainty. Should the Canadian dollar strengthen compared to the U.S. dollar, the resulting negative effect on net earnings would be partially offset by foreign exchange gains on our U.S. dollar denominated debt. The opposite would occur should the Canadian dollar weaken compared to the U.S. dollar. Cash flow from operations is not impacted by the effects of currency fluctuations on our U.S. dollar denominated debt. We are also impacted to a lesser extent by exchange rate fluctuations between the Canadian dollar, the Euro and the British pound.

We mitigate some of the risk associated with changes in commodity prices through the use of derivative financial instruments (see page 19).

SENSITIVITY ANALYSIS[1]

	2009 Average	Change	Approximate Change in Cash Flow from Operations ($ millions)	After-Tax Earnings ($ millions)
Oil Sands				
Realized crude oil price ($/barrel)[2]	61.26	US$1.00	86	65
Sales (bpd)	276 200	1 000	7	5
Natural Gas				
Realized natural gas price ($/mcf)[2]	3.70	Cdn$0.10	13	9
Natural gas sales (mmcf/d)	397.2	10	10	1
East Coast Canada				
Realized crude oil price ($/barrel)[2]	76.86	US$1.00	7	5
Sales (bpd)	58 000	1 000	4	3
International				
Realized crude oil price ($/barrel)[2]	76.11	US$1.00	9	7
Crude oil sales (bpd)	100 500	1 000	6	5
Realized natural gas price ($/mcf)[2]	4.18	US$0.10	1	1
Natural gas sales (mmcf/d)	116.2	10	4	4
Consolidated				
US$/Cdn$ exchange rate effect on U.S. denominated long-term debt	0.88	0.01		92

(1) The sensitivity analysis shows the main factors affecting Suncor's annual cash flow from operations and earnings based on actual 2009 operations. The table illustrates the potential financial impact of these factors applied to Suncor's 2009 results. A change in any one factor could compound or offset other factors.

(2) Includes the impact of hedging activities. See page 19.

Environmental Regulation and Risk

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

Some of the issues that are, or may in future be, subject to environmental regulation include:

- the possible cumulative regional impacts of oil sands development;
- manufacture, import, storage, treatment and disposal of hazardous or industrial waste and substances;
- the need to reduce or stabilize various emissions to air;
- withdrawals, use of, and discharges to, water;
- issues relating to land reclamation, restoration and wildlife habitat protection;
- reformulated gasoline to support lower vehicle emissions; and
- U.S. implementation of regulation or policy to limit its purchases of oil to oil produced from conventional sources, or U.S. state or federal calculation and regulation of fuel lifecycle carbon content.

Changes in environmental regulation could have a potentially adverse effect on our financial results from the standpoint of product demand, product reformulation and quality, methods of production and distribution and costs. For example, requirements for cleaner-burning fuels could cause additional costs to be incurred, which may or may not be recoverable in the marketplace. The complexity and breadth of these issues make it extremely difficult to predict their future impact on us. Management anticipates capital expenditures and operating expenses could increase in the future as a result of the implementation of new and increasingly stringent environmental regulations. Compliance with environmental regulation can require

significant expenditures and failure to comply with environmental regulation may result in the imposition of fines and penalties, liability for clean-up costs and damages, and the loss of important permits and licenses.

Climate Change Legislation Suncor operates in jurisdictions that have regulated or have proposed to regulate industrial GHG emissions. Jurisdictions that currently regulate GHG emissions include Alberta and the European Union. Jurisdictions that have proposed to regulate GHG emissions include the U.S., British Columbia (B.C.), Quebec, Ontario and Canada. Those jurisdictions that have announced the intent to regulate GHG emissions generally support carbon pricing policies such as cap-and-trade systems and, in some cases, have also proposed implementing additional measures, including low carbon fuel standards. Suncor participates both directly and through industry associations in the consultation process on the design of proposed regulations, as well as efforts to harmonize regulations across jurisdictions within North America.

While these jurisdictions have not yet published details on their proposed regulations, or on their compliance mechanisms, many, most notably the U.S., have identified the importance of balancing the environment, economy and energy security when developing regulations. The Canadian government has also recently gone on record to state that its regulations will be consistent with U.S. regulations. While it is premature to predict what impact these anticipated regulations may have on the company and the broader oil and gas sector, the company will likely face increased capital and operating costs in order to comply with these regulations and these costs could be material. In addition, regulation based on life cycle analysis of fuel carbon content may impact markets for oil sands crude oils. Notwithstanding the current regulatory uncertainty, the company assumes that a price will be imposed on carbon dioxide and incorporates a range of potential carbon costs and regulatory outcomes into future capital planning.

In 2007, the Alberta government introduced the Climate Change and Emissions Management Amendment Act, which places intensity (emissions per unit of production) limits on facilities emitting more than 100,000 tonnes of carbon dioxide equivalent per year. Suncor's oil sands operations, the Edmonton Refinery and two Natural Gas Plants in Alberta are subject to this legislation. The act calls for intensity reductions of 12% from an approved baseline, commencing July 1, 2007.

In compliance with this new legislation, the company filed applications in December 2007 to establish baseline intensities for our Alberta facilities. In March 2010, the company must file compliance reports that demonstrate that each facility either met its intensity target for 2009, or took action to offset its emissions intensity. Compliance options available to the company include internal emission reductions, utilizing offset projects or contributing to a government climate change emission management fund.

For the compliance period of January 1 to December 31, 2009, the compliance costs to Suncor's Alberta facilities are estimated at between $3 million and $5 million. Final costs for 2009 will be determined when the company files its compliance report with the Province of Alberta in March 2010.

Suncor's operated facilities in the Netherlands North Sea are subject to the European Union Emissions Trading System and the associated National Allocation Plan. For the compliance period of January 1 to December 31, 2009, Suncor's facilities will have sufficient allocations for compliance.

There remains uncertainty around the outcome and impacts of climate change and other environmental regulations. We continue to actively work to mitigate our environmental impact, including taking action to reduce greenhouse gas emissions, investing in renewable forms of energy such as wind power and biofuels, accelerating land reclamation, installing new emission abatement equipment and pursuing other opportunities such as carbon capture and sequestration.

Tailings Management Another area of risk for Suncor is the reclamation of tailings ponds, which contain water, clay and residual bitumen produced through the extraction process. On October 15, 2009, Suncor applied to the Energy Resources Conservation Board (ERCB) and Alberta Environment (AENV) for permission to amend its existing and/or approved operations east of the Athabasca River to move from the currently adopted tailings management system, being the use of a consolidated tailings (CT) process to consolidate mature fine tailings (MFT), to Suncor's new Tailings Reduction Operations (TRO) strategy, based on MFT drying. This application is currently pending ERCB and AENV approval.

Regulatory Approvals Before proceeding with most major projects, we must obtain regulatory approvals. The regulatory approval process often involves stakeholder consultation, environmental impact assessments and public hearings, among other factors. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis, could result in delays, abandonment, or restructuring of projects and increased costs, all of which could negatively impact future earnings and cash flow.

CRITICAL ACCOUNTING ESTIMATES

Critical accounting estimates are defined as estimates that are important to the portrayal of our financial position and operations, and require management to make judgments based on underlying assumptions about future events and their effects. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as our operating environment changes. Critical accounting estimates are reviewed annually by the Audit Committee of the Board of Directors. The following are the critical accounting estimates used in the preparation of our Consolidated Financial Statements.

Asset Retirement Obligations (ARO)

We are required to recognize a liability for the future retirement obligations associated with our property, plant and equipment. An ARO liability is only recognized to the extent there is a legal obligation associated with the retirement of a tangible long-lived asset that we are required to settle as a result of an existing or enacted law, statute, ordinance, written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying our total ARO amount. These individual assumptions can be subject to change based on experience.

Each year-end cash flow estimates are re-evaluated and increases to the ARO are discounted to present value using a credit-adjusted risk-free discount rate. The ARO accretes over time until we settle the obligation, the effect of which is included in a separate line in the Consolidated Statements of Earnings entitled accretion of asset retirement obligations. The discount rate is adjusted as appropriate, to reflect long-term changes in market rates and outlook.

An ARO is not recognized for assets with an indeterminate useful life because the amount cannot be reasonably estimated. An ARO for these assets will be recorded in the first period in which the lives of the assets are determinable.

In connection with company and third-party reviews of ARO during 2009, we increased our estimated undiscounted total obligation to $8.3 billion from the previous estimate of $3.5 billion. The increase was mainly due to the addition of $4.7 billion in undiscounted ARO as a result of the merger with Petro-Canada. The estimated discounted total obligation at December 31, 2009 was $3.2 billion, compared to $1.6 billion at December 31, 2008.

Employee Future Benefits

We provide a range of benefits to our employees and retired employees, including pensions and other post-retirement benefits. The determination of obligations under our benefit plans and related expenses requires the use of actuarial valuation methods and assumptions. Assumptions typically used in determining these amounts include, as applicable, rates of employee turnover, future claim costs, discount rates, future salary and benefit levels, return on plan assets, mortality rates and future medical costs. The fair value of plan assets is determined using market values. Actuarial valuations are subject to management judgment. Management continually reviews these assumptions in light of actual experience and expectations for the future. Changes in assumptions are accounted for on a prospective basis. Employee future benefit costs are reported as part of operating, selling and general expenses in our Consolidated Statements of Earnings. The accrued benefit liability is reported as part of accrued liabilities and other in the Consolidated Balance Sheets.

The assumed rate of return on plan assets considers the current level of expected returns on the fixed income portion of the plan assets portfolio, the historical level of risk premium associated with other asset classes in the portfolio and the expected future returns on each asset class. The discount rate assumption is based on the year-end interest rate on high-quality bonds with maturity terms equivalent to the benefit obligations. The rate of compensation increases is based on management's judgment. The accrued benefit obligation and net periodic benefit cost for both pensions and other post-retirement benefits may differ significantly if different assumptions are used.

Property, Plant and Equipment and Depreciation, Depletion and Amortization

We account for our exploration and production related to our oil and gas producing activities using the successful efforts method. This policy was selected over the alternative of the full-cost method because we believe it provides timelier accounting of the success or failure of exploration and production activities.

The application of the successful efforts method of accounting requires management to determine the proper classification of activities designated as developmental or exploratory, which then determines the appropriate accounting treatment of the costs incurred. The results

from a drilling program can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Where it is determined that exploratory drilling will not result in commercial production, the drilling costs of the exploratory dry hole are written off and reported as part of exploration expenses in the Consolidated Statements of Earnings. Dry hole expense can fluctuate from year to year due to such factors as the level of exploratory spending, the level of risk sharing with third parties participating in the exploratory drilling and the degree of risk in drilling in particular areas.

Properties that are assumed to be productive may, over a period of time, actually deliver oil and gas in quantities different than originally estimated because of changes in reservoir performance. Such changes may require a test for the potential impairment of capitalized properties based on estimates of future cash flow from the properties. An impairment test may also be required as a result of other economic events. Estimates of future cash flows are subject to significant management judgment concerning oil and gas prices, production quantities, operating costs and future development costs. Where properties are assessed by management to be fully or partially impaired, the book value of the properties is reduced to fair value and either completely removed (written off) or partially removed (written down) in our records and reported as part of depreciation, depletion and amortization expenses, in the Consolidated Statements of Earnings.

Asset Impairment

Producing properties and significant unproved properties are assessed annually, or as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated net undiscounted future cash flows with the carrying value of the asset. The cash flows used in the impairment assessment require management to make assumptions and estimates about recoverable reserves, future commodity prices and operating costs. Changes in any of the assumptions, such as a downward revision in reserves, a decrease in future commodity prices or an increase in operating costs, could result in an impairment of an asset's carrying value.

Purchase Price Allocation

Business acquisitions are accounted for by the purchase method of accounting. Under this method, the purchase price is allocated to the assets acquired and the liabilities assumed based on the fair value at the time of the acquisition. The excess purchase price over the fair value of identifiable assets and liabilities acquired is goodwill. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of property, plant and equipment acquired generally require the most judgment and include estimates of reserves acquired (see Oil and Gas Reserves below), future commodity prices and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill in the purchase price allocation. Future net earnings can be affected as a result of changes in future depreciation and depletion, asset impairment or goodwill impairment.

Income Taxes

The company follows the liability method of accounting for income taxes, whereby future income taxes are recognized based on the differences between the carrying amounts of assets and liabilities reported in the financial statements and their respective tax bases. The determination of the income tax provision is an inherently complex process, requiring management to interpret continually changing regulations and to make certain judgments. While income tax filings are subject to audits and reassessments, management believes adequate provision has been made for all income tax obligations. However, changes in the interpretations or judgments may result in an increase or decrease in the company's income tax provision in the future.

Contingencies

The company is involved in litigation and claims in the normal course of operations. Management is of the opinion that any resulting settlements would not materially affect the financial position of the company as at December 31, 2009. However, the determination of contingent liabilities relating to litigation and claims is a complex process that involves judgments as to the outcomes and interpretation of laws and regulations. Changes in the judgments or interpretations may result in an increase or decrease in the company's contingent liabilities in the future.

Oil and Gas Reserves

Reserves estimates, although not reported as part of the company's Consolidated Financial Statements, can have a significant effect on net earnings as a result of their impact on depreciation and depletion rates, asset impairments and goodwill impairments. Our oil and gas reserves are evaluated by independent qualified reserves evaluators. The estimation of reserves is an inherently complex process and involves the exercise of professional judgment.

Estimates are based on projected future rates of production, estimated commodity prices, engineering data and the timing of future expenditures, all of which are subject to uncertainty.

RESERVES ESTIMATES

As a Canadian issuer, Suncor is subject to the reporting requirements of the Canadian Securities Administrators (CSA), including the reporting of our reserves in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* (NI 51-101). In order to harmonize its oil and gas disclosure in both Canada and the United States, Suncor applied for, and received, an exemption from Canadian securities regulatory authorities permitting Suncor to report its reserves in accordance with the rules and regulations of the United States Securities and Exchange Commission (SEC). See "Reliance on Exemptive Relief" in our Annual Information Form dated March 5, 2010. The SEC has updated its oil and gas disclosure requirements with the issuance of its final rule, Modernization of Oil and Gas Reporting, on December 31, 2008. Under the new SEC rule, disclosure of probable reserves is now permitted in addition to proved reserve. Disclosure of oil sands mining and upgrading as oil and gas activities is also permitted. Suncor's 2009 reserves disclosure includes both proved and probable reserves for all of our oil and gas operations including our oil sands areas and associated upgrading facilities.

Differences in the estimates of the reserves between U.S. disclosure requirements and NI 51-101 can be material mainly due to differences in the stipulated product prices to be used for reserve evaluations. U.S. disclosure requirements mandate the use of an average of first day of the month price for the twelve months prior to the end of the reporting period, while Canadian securities regulatory authorities require a forecasted price. However this difference in pricing methodologies did not have a material impact on Suncor's 2009 reserves disclosure.

In addition to reporting our reserves in accordance with U.S. disclosure requirements, we are also providing voluntary additional disclosure (which does not conform to U.S. disclosure requirements). Our voluntary additional disclosure will differ from our required U.S. disclosure in the following ways:

- Disclosure of reserves on a gross basis (before royalty) voluntarily, as well as the required net basis (after royalty) under U.S. disclosure requirements.
- Disclosure of proved and probable reserve totals on a gross basis (before royalty) together, in addition to reporting them separately on a net basis (after royalty) as required under U.S. disclosure requirements.
- Disclosure of contingent resources and remaining recoverable resources on a gross basis (before royalty) following NI 51-101 requirements (disclosure of resources is not recognized under U.S. disclosure requirements).

The majority of Suncor's proved reserves and probable reserves are in Canada, both in the Canadian oil sands, and conventional type plays in Western Canada and offshore on the east coast of Canada. Suncor also has other North American proved and probable reserves in the United States and international proved and probable reserves in the North Sea, Syria, Libya, and Trinidad and Tobago.

For more information regarding our reserves and resource disclosure, please see "Reserve Estimates" in our Annual Information Form dated March 5, 2010, which section of the Annual Information Form is incorporated into this MD&A by reference.

Merger of Suncor and Petro-Canada

Effective August 1, 2009, Suncor Energy Inc. (as it existed at that time) and legacy Petro-Canada amalgamated to form a single corporation continuing under the name "Suncor Energy Inc.". The addition of the Petro-Canada properties is being shown as a purchase by Suncor. In determining the purchased volumes, Petro-Canada's 2008 closing reserve balances were used and adjusted for 2009 production volumes and any purchases or sales of assets prior to August 1, 2009. A total of 752 millions of barrels (MMbbls) of proved oil volumes on a net basis (after royalty) and 1,179 billion cubic feet (Bcf) of proved natural gas volumes on a net basis (after royalty) were added to Suncor's proved reserves base as a result of the merger.

REQUIRED U.S. OIL AND GAS DISCLOSURE

The table below shows Suncor's 2009 year-end balances for proved and probable reserves, and was prepared in accordance with SEC standards for oil and gas activities:

Summary of Oil and Gas Reserves After Royalties [1], [2], [3], [5]

Reserve category	Reserves				Reserve category	Reserves			
	Oil & NGL	Natural Gas	SCO	Bitumen		Oil	Natural Gas	SCO	Bitumen
	(MMbbls)	(BCF)	(MMbbls)	(MMbbls)		(MMbbls)	(BCF)	(MMbbls)	(MMbbls)
PROVED					**PROBABLE**				
Developed					**Developed**				
North Sea [4]	**72**	**29**	—	—	North Sea [4]	**36**	**23**	—	—
Other International [6], [7]	**38**	**93**	—	—	Other International [6], [7]	**30**	**42**	—	—
North America Onshore	**35**	**1 229**	—	—	North America Onshore	**6**	**282**	—	—
East Coast Canada	**41**	—	—	—	East Coast Canada	**39**	—	—	—
Oil Sands In-situ	—	—	**152**	**22**	Oil Sands In-situ	—	—	**69**	**8**
Oil Sands Mining [8]	—	—	**1 899**	—	Oil Sands Mining [8]	—	—	**287**	—
Total Developed	**186**	**1 351**	**2 051**	**22**	**Total Developed**	**111**	**347**	**356**	**8**
Undeveloped					**Undeveloped**				
North Sea [4]	**69**	—	—	—	North Sea [4]	**36**	**50**	—	—
Other International [6], [7]	**6**	**294**	—	—	Other International [6], [7]	**31**	**222**	—	—
North America Onshore	**7**	**48**	—	—	North America Onshore	**9**	**211**	—	—
East Coast Canada	**26**	—	—	—	East Coast Canada	**60**	—	—	—
Oil Sands In-situ	—	—	**514**	**389**	Oil Sands In-situ	—	—	**507**	**1 336**
Oil Sands Mining [8]	—	—	—	—	Oil Sands Mining [8]	—	—	**237**	—
Total Undeveloped	**108**	**342**	**514**	**389**	**Total Undeveloped**	**136**	**483**	**744**	**1 336**
TOTAL PROVED	**294**	**1 693**	**2 565**	**411**	**TOTAL PROBABLE**	**247**	**830**	**1 100**	**1 344**

(1) Numbers in the above table are rounded to the nearest 1 MMbbls or 1 Bcf.

(2) The reserves data are based upon evaluations by GLJ Petroleum Consultants Ltd., Sproule Associates Limited, RPS Energy Plc and Suncor with an effective date of December 31, 2009 and does not account for any planned divestiture after the effective date. GLJ, Sproule, and RPS summary reserve reports are contained in Schedules "E", "F", "G" to our Annual Information Form dated March 5, 2010.

(3) Proved reserves before royalties are Suncor's working interest reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. Reserve quantities after royalty also reflect net overriding royalty interests paid and received.

(4) Reserves in the North Sea are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in the Netherlands.

(5) Proved reserves include quantities of crude oil and natural gas, which will be produced under arrangements, which involve the company or its subsidiaries in upstream risks and rewards, but which do not transfer title of the product to those companies.

(6) In Suncor's production sharing contracts (PSCs), after royalty proved reserves have been determined using the economic interest method and includes the company's share of future production entitlement calculated using the contract's cost recovery and profit oil terms. The entitlement reserves are then adjusted to include reserves relating to income tax payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa), since the bbls necessary to achieve cost recovery change with the prevailing oil prices.

(7) All reserves reported in "Other International" (which include reserves in Libya, Syria, and Trinidad and Tobago) are calculated as per footnote 5.

(8) Due to the SEC rule change in respect to reporting mining as an oil and gas activities, Suncor has included oil sands mining reserves which would have been previously reported under Mining Guide 7. For more information, see page 30 of our Annual Information Form dated March 5, 2010.

VOLUNTARY ADDITIONAL DISCLOSURE (does not conform to U.S. disclosure requirements)

Proved and Probable Reserves Before Royalties [1], [2], [3], [5], [11]

	Oil and Gas Activities											
	International				North America						Totals	
	North Sea [4]		Other International [6], [7]		North America Onshore		East Coast Canada	In-Situ		Oil Sands Mining [9]		
	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	SCO	Bitumen	SCO	Crude Bitumen, SCO & NGL	Natural Gas
	(MMbbls)	(Bcf)	(MMbbls)	(Bcf)	(MMbbls)	(Bcf)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(Bcf)
End of Year 2008 [10]	**—**	**—**	**—**	**—**	**9**	**734**	**—**	**2 565**	**148**	**2 316**	**5 038**	**734**
Revisions of previous estimates [8]	6	(18)	6	247	15	(52)	16	(1 587)	1 863	(72)	247	177
Sale of reserves in place	—	—	—	—	—	(6)	(3)	—	—	—	(3)	(6)
Purchase of reserves in place	215	98	276	618	47	1 498	213	437	—	638	1 826	2 214
Discoveries, extensions and improved recovery	3	29	9	352	1	52	7	—	—	—	20	433
Production	(11)	(8)	(5)	(11)	(4)	(146)	(8)	(16)	(1)	(88)	(133)	(165)
End of Year 2009	**213**	**101**	**286**	**1 206**	**68**	**2 080**	**225**	**1 399**	**2 010**	**2 794**	**6 995**	**3 387**
Proved & Probable Undeveloped Reserves												
End of year 2009	**105**	**50**	**89**	**1 065**	**19**	**309**	**114**	**1 160**	**1 977**	**264**	**3 728**	**1 424**

(1) Numbers in the above table are rounded to the nearest 1 MMbbls or 1 Bcf.

(2) The reserves data are based upon evaluations by GLJ Petroleum Consultants Ltd., Sproule Associates Limited, RPS Energy Plc and Suncor with an effective date of December 31, 2009 and does not account for any planned divestiture after the effective date. GLJ, Sproule, and RPS summary reserve reports are contained in Schedules "E", "F", "G" to our Annual Information Form dated March 5, 2010.

(3) Proved reserves before royalties are Suncor's working interest reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. Reserve quantities after royalty also reflect net overriding royalty interests paid and received.

(4) Reserves in the North Sea are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in the Netherlands.

(5) Proved reserves include quantities of crude oil and natural gas, which will be produced under arrangements, which involve the company or its subsidiaries in upstream risks and rewards, but which do not transfer title of the product to those companies.

(6) In Suncor's production sharing contracts (PSCs), after royalty proved reserves have been determined using the economic interest method and includes the company's share of future production entitlement calculated using the contract's cost recovery and profit oil terms. The entitlement reserves are then adjusted to include reserves relating to income tax payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa), since the bbls necessary to achieve cost recovery change with the prevailing oil prices.

(7) All reserves reported in "Other International" (which include reserves in Libya, Syria, and Trinidad and Tobago) are calculated as per footnote 5.

(8) Revisions include changes in previous estimates, either upward or downward, resulting from new information (except an increase in acreage) normally obtained from drilling or production history or resulting from a change in economic factors.

(9) Due to the SEC rule change in respect to reporting mining as an oil and gas activities, Suncor has re-stated its mining opening balance which would have been previously reported under Mining Guide 7.

(10) The 2008 reserve data for legacy Suncor assets has been restated per SEC guidelines, this information was previously disclosed under NI 51-101. For more information, see page 30 of our Annual Information Form dated March 5, 2010.

(11) The production data in the 2009 reserve tables are estimates from the third party evaluators, and may not exactly match production shown elsewhere in this Annual Report and our Annual Information Form dated March 5, 2010. Any variance in the production numbers is deemed not material in the disclosure of these reserves.

REMAINING RECOVERABLE RESOURCES (does not conform to U.S. disclosure requirements)

Besides Suncor's proved plus probable reserve holdings, we also have considerable contingent resources (see table below). GLJ prepared the estimates for legacy Suncor and Syncrude mining leases as well as the Firebag in-situ leases. Sproule audited the Fort Hills estimate. Estimates for the remainder of our contingent resources were prepared internally by qualified reserves evaluators.

Remaining Recoverable Resources Before Royalties

As at December 31, 2009 [1]	Conventional (MMBOEs)	Mining (MMBOEs)	In-Situ (MMBOEs)	Total (MMBOEs)
Total Proved	751	2 203	1 177	4 131
Total Probable	606	591	2 232	3 429
Total Proved Plus Probable Reserves	**1 357**	**2 794**	**3 409**	**7 560**
Contingent Resources [2], [5], [6] – Best Estimate [3]	2 935	6 080	10 881	19 896
Remaining Recoverable Resources (unrisked) [4]	**4 292**	**8 874**	**14 290**	**27 456**

(1) Numbers in the above table are rounded to the nearest 1 million. MMBOE means millions of barrels of oil equivalent and is comprised of all liquids: 1 MMbbl = 1 MMboe and natural gas: 6 bcf = 1 MMBOE.

(2) Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. There is no certainty that it will be commercially viable to produce the contingent resources.

(3) Best Estimate is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. The best estimate of potentially recoverable volumes is generally prepared independent of the risks associated with achieving commercial production.

(4) Remaining recoverable resources (unrisked) are the arithmetic sum of proved and probable reserves and best estimate contingent resources. Suncor has not quantified potentially recoverable volumes from either undiscovered accumulations or its carbonate leases. The contingent resources have not been adjusted for risk based on the chance of development. It is not an estimate of volumes that may be recovered. Actual recovery may be less.

(5) Our contingent resources are composed primarily of resources from: (i) (in-situ) Firebag, Lewis, Meadow and Chard; (ii) (mining) Voyager South, Audette (North Leases), Fort Hills and Syncrude; and (iii) (conventional) Arctic Islands and MacKenzie corridor, Libya, Hebron/BenNevis, Labrador, White Rose, Hibernia, Terra Nova, Trinidad and Tobago and the North Sea.

(6) All mining and in-situ contingent resources are stated in SCO.

Remaining recoverable resources were 27,456 millions of barrels of oil equivalent at December 31, 2009. The increase in 2009 was primarily due to the merger with Petro-Canada.

Approximately 85% of our contingent resources are associated with our long term mining and in-situ growth projects. The remaining contingent resources are associated with our frontier North America and International assets. Contingent resources may require additional delineation drilling, future corporate approval to proceed with development, additional regulatory approvals and other commercial factors to be put in place.

Remaining recoverable resources are the best estimate of Suncor's total resource assets, which form the basis of our long term business plans and production growth. Management believes that this metric is also useful in comparing Suncor's resource base to that of our competitors. Readers are cautioned that the manner in which remaining recoverable resources are calculated may differ across companies and for that reason, direct comparisons may not be possible in some instances.

Estimates of contingent resources have not been adjusted for risk based on the chance of development. Such estimates are not estimates of volumes that may be recovered and actual recovery is likely to be less and may be substantially less or zero. There is no certainty as to the timing of such development.

There is no certainty that all or any portion of the contingent resource will be commercially viable to produce. For movement of resources to reserves categories, all projects must have an economic depletion plan and may require, among other things: (i) additional delineation drilling and/or new technology for unrisked contingent resources; (ii) regulatory approvals; and (iii) company approvals to proceed with development, among other things.

For a discussion of the properties and projects that are associated with our remaining recoverable resources, see our Annual Information Form dated March 5, 2010.

CONTROL ENVIRONMENT

Based on their evaluation as of December 31, 2009, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the United States Securities Exchange Act of 1934 (the Exchange Act)) are effective to ensure that information required to be disclosed by us in reports that we file or submit to Canadian and U.S. securities authorities is recorded, processed, summarized and reported within the time periods specified in Canadian and U.S. securities laws. In addition, as of December 31, 2009, there were no changes in our internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) – 15d-15(f)) that occurred during 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We will continue to periodically evaluate our disclosure controls and procedures and internal control over financial reporting and will make any modifications from time-to-time as deemed necessary.

The company has undertaken a comprehensive review of the effectiveness of its internal control over financial reporting based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). For the year ended December 31, 2009, based on that evaluation, the company's internal controls were found to be operating free of any material weaknesses.

On August 1, 2009, Suncor completed its merger with Petro-Canada. As permitted by the Securities and Exchange Commission, management has excluded Petro-Canada from its evaluation of the effectiveness of Suncor's internal control over financial reporting as of December 31, 2009. Assets attributable to Petro-Canada as of August 1, 2009 represented approximately 50% of Suncor's total assets as of August 1, 2009, and revenues attributable to Petro-Canada for the period August 1 – December 31, 2009 represented approximately 25% of Suncor's total revenues for the year ended December 31, 2009.

The effectiveness of our internal control over financial reporting as at December 31, 2009 was audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2009.

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

CHANGES IN ACCOUNTING POLICIES

(a) Goodwill and Intangible Assets

On January 1, 2009, the company retroactively adopted Canadian Institute of Chartered Accountants (CICA) Handbook section 3064 "Goodwill and Intangible Assets." This new standard replaces section 3062 "Goodwill and Other Intangible Assets" and section 3450 "Research and Development Costs," and focuses on the criteria for asset recognition in the financial statements, including those internally developed. The impact of adopting this standard resulted in a change in the classification of our deferred maintenance shutdown costs that had previously been classified within other assets and amortized over the period to the next shutdown. At December 31, 2008, property, plant and equipment was increased by $566 million, with an equal and offsetting reduction to other assets.

(b) Financial Instruments Disclosures

On September 30, 2009, the company prospectively adopted amendments to CICA Handbook section 3862 "Financial Instruments: Disclosures". The section has been amended to include additional disclosure requirements about fair value measurements of financial instruments and to enhance liquidity risk disclosure requirements. The additional disclosures required by these amendments are provided in note 4 to the December 31, 2009 audited Consolidated Financial Statements.

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

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

(d) International Financial Reporting Standards

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

The company has successfully completed the integration of the legacy Petro-Canada and Suncor's IFRS conversion projects. Key activities included integrating the project plans, reviewing the accounting documentation, aligning the IFRS accounting conclusions, and reviewing the design of the Information Technology dual reporting solutions.

The company is currently engaged in the implementation phase of its IFRS project and continues to be on target to meet the changeover date. Please see the following table for select project activities within the implementation phase and an assessment of progress. Note that new and revised IFRS developments will be monitored throughout the project but may result in changes to the project activities described below.

IFRS Conversion Project

Key Activity	Key Milestones	Status
Financial Statement Preparation: – Identify differences in Canadian GAAP/IFRS accounting policies. – Select Suncor's ongoing IFRS policies. – Develop financial statement format. – Quantify effects of change in initial IFRS disclosure and 2010 financial statements.	Senior management and steering committee sign-off for all key IFRS accounting policy choices to occur during 2009. Develop draft financial statement format to occur during 2009.	Completed integrated technical analysis of IFRS differences. Initial analysis of IFRS accounting policy choices completed and presented to senior management including an evaluation of IFRS 1 transition exemptions. Further analysis will be ongoing throughout 2010. Prepared initial draft pro-forma financial statements and continued to review draft disclosures for the merged company.
Training: Define and introduce appropriate level of IFRS expertise for each of the following: – Financial reporting group and operating accounting staff. – Suncor management. – Audit Committee.	Financial reporting group and operating accounting staff training to occur during 2009 as needed. Additional training will occur throughout the project as needs are reassessed. Suncor management and Audit Committee training scheduled to occur during 2009.	Training and communication sessions provided for senior management, Financial Reporting and key individuals within the Business. Education and training sessions will continue throughout the company in 2010. Regular reporting and training has continued for the company's senior executive management and the Audit Committee. IFRS disclosure in the financial statements and MD&A will be updated throughout the project.
Infrastructure: Confirm that business processes and systems are IFRS compliant, including: – Program upgrades/changes. – Gathering data for disclosures.	Confirm that systems can address 2010 dual reporting requirements by 2009 and identify areas requiring change. Confirmation that business processes and systems are IFRS compliant will occur throughout the project.	Development and initial testing of approved IFRS Information Technology solution is underway including creation of IFRS dual reporting accounts. Identified business process and implementation changes and initiated detailed implementation plans.
Control Environment: – For all accounting policy changes identified, assess control design and effectiveness implications. – Implement appropriate changes.	All key control and design effectiveness implications to be assessed as part of the key IFRS differences and accounting policy choices through 2009.	Completed preliminary review of control environment and do not anticipate material changes to internal and disclosure controls over financial reporting.
External Communications: Assess the effects of key IFRS related accounting policy and financial statement changes on external communications. In particular: – Confirm 2011 investor communications are IFRS compliant regarding guidance and and expected earnings. – Monitor and update MD&A communications package. – Confirm investor relations process can respond to IFRS-related queries.	Analyze and publish the effect of IFRS on the financial statements throughout the project.	IFRS disclosures in the MD&A are updated throughout the project. Vice President, Investor Relations is part of the IFRS Steering Committee.

The company has not yet determined the full effects of adopting IFRS. The company's preliminary view of the key areas where changes in accounting policies are expected that may impact the company's consolidated financial statements are listed below. The list and comments below should not be regarded as a complete list of changes that will result from the transition to IFRS. It is intended to highlight those areas the company believes to be most significant; however, analysis of changes is still in progress and not all decisions have been made where choices of accounting policies are available. At this stage, the company has not quantified the impacts expected on its consolidated financial statements for these differences.

Note that most adjustments required on transition to IFRS will be made retrospectively, against opening retained earnings in the first comparative balance sheet. Transitional adjustments relating to those standards where comparative figures are not required to be restated because they are applied prospectively will only be made as of the first day of the year of transition.

IFRS 1 "First-Time Adoption of International Financial Reporting Standards" provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions, in certain areas, to the general requirement for full retrospective application of IFRS. The company is analyzing the various accounting policy choices available and will implement those determined to be most appropriate in the company's circumstances.

Property, Plant & Equipment

International Accounting Standard (IAS) 16 "Property, Plant & Equipment" and Canadian GAAP contain the same basic principles, however there are some differences. IFRS requires that significant parts of an asset be depreciated separately and depreciation commences when the asset is available for use. IFRS also permits property, plant and equipment to be measured using the fair value model or the historical cost model. The company is not planning on adopting the fair value measurement model for its property, plant and equipment.

IFRS 1 contains an elective exemption where an entity may elect to reset as the new cost basis for property, plant and equipment, its fair value at the date of transition. The company is not planning on adopting this exemption and will continue to measure its property, plant and equipment at cost.

Impairment of Assets

Impairments under IAS 36 "Impairment of Assets" are based on discounted cash flows. Under Canadian GAAP, if an asset's estimated undiscounted future cash flows are below its carrying amount a writedown is required and is determined by the amount which the carrying amount exceeds the discounted cash flows. There is no undiscounted test under IFRS. This may result in more frequent write-downs where carrying values of assets were previously supported under Canadian GAAP on an undiscounted cash flow basis, but could not be supported on a discounted cash flow basis.

In addition, under IAS 36 a favorable change in the circumstance that resulted in an impairment of an asset, other than goodwill, would trigger the requirement for a redetermination of the amount of the impairment with any reversal being recognized in income to the extent the asset had previously been impaired. Under Canadian GAAP, impairments are not reversed.

Provisions, Contingent Liabilities and Contingent Assets

IAS 37 "Provisions, Contingent Liabilities and Contingent Assets," requires a provision to be recognized when: there is a present obligation as a result of a past transaction or event; it is probable that an outflow of resources will be required to settle the obligation; and a reliable estimate can be made of the obligation. "Probable" in this context means more likely than not. Under Canadian GAAP, the criterion for recognition in the financial statements is "likely," which is a higher threshold than "probable." Therefore, it is possible that there may be some contingent liabilities, which would meet the recognition criteria under IFRS that were not recognized under Canadian GAAP.

Other differences between IFRS and Canadian GAAP exist in relation to the measurement of provisions, such as the methodology for determining the best estimate where there is a range of equally possible outcomes (IFRS uses the mid-point of the range, whereas Canadian GAAP used the low-end of the range) and the requirement under IFRS for provisions to be discounted where material. In addition, IFRS requires changes to timing, cash flow estimates and discount rates be applied prospectively. Canadian GAAP is similar; however, changes to the discount rates for ARO are only applied to the incremental increases in the liability and not the entire liability.

Share-Based Payments

IFRS 2 "Share-based Payment," requires that cash-settled share-based payments to employees are measured (both initially and at each reporting period) based on the fair values of the awards. Canadian GAAP on the other hand requires that such payments be measured based on the intrinsic values of the awards. This difference is expected to impact the accounting measurement of some of Suncor's cash-settled employee incentive plans.

Income Taxes

Under IAS 12 "Income Taxes," current and deferred tax are normally recognized in the income statement, except to the extent that tax arises from (1) an item that has been recognized directly in equity, whether in the same or a different period, (2) a business combination or (3) a share-based payment transaction. If a deferred tax asset or liability is remeasured subsequent to initial recognition, the impact of remeasurement is recorded in earnings, unless it relates to an item originally recognized in equity, in which case the change would also be recorded in equity. The practice of tracking the remeasurement of taxes back to the item which originally triggered the recognition is commonly referred to as "backwards tracing." Canadian GAAP prohibits backwards tracing except on business combinations and financial reorganizations.

Employee Benefits

IAS 19 "Employee Benefits," requires the past service cost element of defined benefit plans to be expensed on an accelerated basis, with vested past service costs expensed immediately and unvested past service costs recognized on a straight line basis until the benefits become vested. Under Canadian GAAP, past service costs are generally amortized on a straight line basis over the expected average remaining service period of active employees in the plan. In addition, actuarial gains and losses are permitted under IAS 19 to be recognized directly in equity rather than through profit or loss. IFRS 1 also provides an option to recognize all cumulative actuarial gains and losses existing at the date of transition immediately in retained earnings.

RECENTLY ISSUED CANADIAN ACCOUNTING STANDARDS

Business Combinations

In January 2009, the CICA issued section 1582 "Business Combinations" to replace section 1581. The CICA concurrently issued section 1601 "Consolidated Financial Statements" and section 1602 "Non-Controlling Interests" which replace section 1600 "Consolidated Financial Statements." Prospective application of the standards is effective for fiscal years beginning on or after January 1, 2011, with early adoption permitted. The new standards revise guidance on the determination of the carrying amount of the assets acquired and liabilities assumed, goodwill and accounting for non-controlling interests at the time of a business combination. The company applied section 1581 to the Petro-Canada business combination; however, the company will continue to consider the application of section 1582 to business combinations in 2010.

OIL SANDS

Located in northeast Alberta, our oil sands business forms the foundation of our operations and represents the most significant portion of our assets. Our oil sands operations recover bitumen through mining and in-situ development and upgrade it into refinery feedstock, diesel fuel and byproducts. Our marketing plan also allows for sales of bitumen when market conditions are favourable or when operating conditions warrant. The majority of our oil sands assets are owned and operated solely by Suncor. Following the merger with Petro-Canada, our oil sands business also includes a 12% share in the Syncrude oil sands joint venture and a 60% share in the proposed Fort Hills oil sands project.

Oil sands strategy focuses on:

- Developing long-life leases with substantial bitumen resources in place.
- Sourcing low-cost bitumen supply through mining in-situ development and third-party supply agreements, and upgrading this bitumen supply into high value crude oil products.
- Increasing production capacity and improving reliability through staged expansion, continued focus on operational excellence and worksite safety.
- Reducing costs through the application of technologies, economies of scale, direct management of growth projects, strategic alliances with key suppliers and continuous improvement of operations.
- Pursuing new technology applications to increase production, mitigate costs and reduce environmental impacts.

HIGHLIGHTS

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	**2009**	2008	2007
Revenue (net of royalties)	**6 539**	8 639	6 175
Production (excluding Syncrude) (thousands of bpd)	**290.6**	228.0	235.6
Syncrude production (thousands of bpd)[1]	**38.5**	—	—
Average sales price (excluding Syncrude) ($/barrel)	**61.26**	95.96	74.01
Net earnings	**557**	2 875	2 474
Operating earnings[2]	**1 066**	2 522	2 137
Cash flow from operations[2],[3]	**1 251**	3 507	3 165
Total assets	**37 553**	25 795	18 172
Cash used in investing activities	**(3 546)**	(6 996)	(4 248)
Sales mix (light/heavy mix)	**47/53**	43/57	54/46
Cash operating costs (excluding Syncrude) ($/barrel)[2]	**33.95**	38.50	27.80
ROCE (%)[2], [4]	**4.2**	35.5	43.0
ROCE (%)[2], [5]	**2.5**	21.8	27.9

(1) Reflects results of operations since the merger with Petro-Canada on August 1, 2009.

(2) Non-GAAP measures. See pages 52 and 53.

(3) Calculation of this measure has been revised, and prior period comparative figures have been restated. See page 52.

(4) Excludes capitalized costs related to major projects in progress. Return on capital employed (ROCE) for our operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non-GAAP Financial Measures.

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

2009 Overview

- Low benchmark prices and losses on derivative contracts used for risk management purposes significantly reduced Oil Sands price realizations in 2009. The average WTI crude oil price was 38% lower in 2009 than in 2008. Derivative contracts entered into to protect our future revenues ended up negatively impacting our results when crude prices strengthened later in the year, and settlement prices were lower than benchmark prices.
- Production (excluding proportionate production share from Syncrude joint venture) averaged 290,600 bpd in 2009, compared to 228,000 bpd in 2008, with record production reported in November 2009. Production volumes were up year-over-year primarily as the result of improved upgrader reliability and increased bitumen supply. However, unplanned maintenance following a fire in December negatively impacted production, and a subsequent fire in February 2010 will reduce production volumes in 2010.
- Cash operating costs for our oil sands operations (excluding Syncrude) averaged $33.95 per barrel during 2009, compared to $38.50 per barrel in 2008. The lower costs in 2009 are primarily due to the increase in production and a decrease in natural gas prices and third-party bitumen purchases. These factors were partially offset by an increase in operational expenses primarily due to the inclusion of operating costs from MacKay River as a result of the merger with Petro-Canada.
- In response to market uncertainty at the beginning of 2009, a revised capital spending plan deferred Oil Sands growth projects. Although the 2010 capital plan announced in November 2009 has restarted construction of certain projects, the costs associated with keeping projects in "safe mode" totalled $380 million pre-tax in 2009.

Operating Earnings [1]

Year ended December 31 ($ millions, after-tax)	**2009**	2008	2007
Oil Sands net earnings as reported	**557**	2 875	2 474
Change in fair value of commodity derivatives used for risk management	**499**	(372)	—
Mark-to-market valuation of stock-based compensation	**28**	(5)	27
Project start-up costs	**40**	24	49
Impact of income tax rate reductions on opening future income tax liabilities [2]	**37**	—	(413)
Costs related to deferral of growth projects	**299**	—	—
Gain on effective settlement of pre-existing contract with Petro-Canada [3]	**(438)**	—	—
Impact of recording acquired inventory at fair value [4]	**5**	—	—
Losses and adjustments on significant disposals [5]	**39**		
Oil Sands operating earnings	**1 066**	2 522	2 137

(1) Non-GAAP measure. See page 52 for a discussion of operating earnings.

(2) In the third quarter of 2009, an increase in the future income tax liabilities resulted from a revised provincial allocation for income tax purposes due to the merger with Petro-Canada. This was partially offset for the year ended December 31, 2009 by a reduction to the Ontario income tax rate in the fourth quarter of 2009, resulting in a decrease in the future income tax liabilities. See note 7 to the Consolidated Financial Statements.

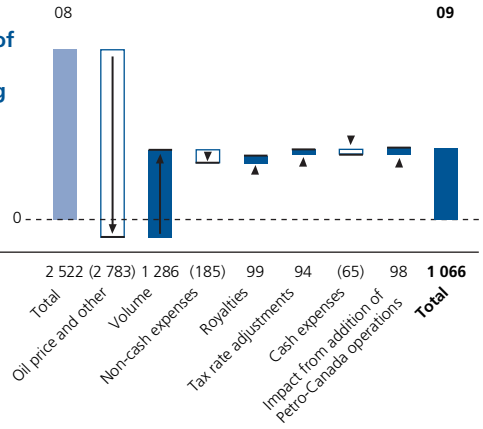
(3) Impact from deemed settlement value assigned to bitumen processing contract with Petro-Canada upon close of merger (see note 2 to the Consolidated Financial Statements).

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

(5) Includes loss recognized when a highway interchange constructed by Suncor was transferred to the Provincial government of Alberta.

Net earnings were $557 million in 2009, compared to $2.875 billion in 2008 (2007 – $2.474 billion). Operating earnings for 2009 were $1.066 billion, compared to $2.522 billion in 2008 (2007 – $2.137 billion). Earnings decreased primarily as a result of lower average price realizations for oil sands crude products, partially offset by higher production and sales volumes.

Bridge Analysis of Oil Sands Operating Earnings
($ millions)



The decrease in price realizations reflects significantly lower benchmark West Texas Intermediate (WTI) crude oil prices, as well as realized losses of approximately $315 million after-tax on risk management derivative contracts as the settlement prices were lower than benchmark prices for much of the year. This was partially offset by a decreased discount to WTI on our sweet crude blends and sour crude blends, increased sales of higher value sweet crude products, and a weaker Canadian dollar.

Oil Sands Production

Year ended December 31 Thousands of barrels per day	**2009**	2008	2007	2006	2005
Oil Sands production (excluding Syncrude)	**290.6**	228.0	235.6	260.0	171.3
Syncrude [(1)]	**38.5**	—	—	—	—

(1) Reflects our share of Syncrude production since the merger with Petro-Canada on August 1, 2009.

Oil Sands average production (excluding Syncrude) was 290,600 bpd in 2009, compared to 228,000 bpd in 2008. Production was higher in 2009 due mainly to improved upgrader reliability and increased bitumen supply. In addition, production in 2008 was negatively impacted by planned and unplanned maintenance shutdowns in our upgrading and extraction assets, as well as a regulatory cap on our Firebag in-situ operations, which was lifted in July 2008.

As a result of the merger, Suncor holds a 12% share in the Syncrude joint venture oil sands operations located close to Suncor's existing oil sands operations in Fort McMurray, Alberta, Canada. Syncrude operations contributed an additional average 38,500 bpd of sweet synthetic crude production in the last five months of 2009.

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

Sales volumes in 2009 averaged 276,200 bpd, compared with 227,000 bpd in 2008. The increase was due primarily to increased production in legacy Suncor's oil sands operations and the addition of sales volumes from MacKay River as a result of the merger.

Production for 2009 was reduced due to unplanned maintenance activities following a December 2009 fire at one of our upgraders. Overall average production volumes in 2009 were impacted by approximately 7,600 barrels per day as a result of the fire. Repairs of the upgrader were completed and operations returned to normal in early February 2010.

Sales price realizations averaged $61.26 per barrel in 2009, compared with $95.96 per barrel in 2008. This was primarily due to a significant decrease in the average benchmark WTI crude oil price of about 38%. This was partially offset by a decreased discount to WTI on our sweet crude blends and sour crude blends and an increased proportion of higher priced sweet crude products in our sales mix.

Cash Expenses

Cash expenses increased year-over-year, primarily due to increased costs associated with higher production and sales volumes in 2009 as compared to 2008, as well as additional costs from Petro-Canada operations. These factors were partially offset by reduced energy input costs as a result of lower natural gas pricing and a decrease in purchases of third-party bitumen. Overall, increased cash expenses reduced operating earnings by $65 million.

Royalties

Alberta Crown royalties decreased in 2009 as compared to 2008, due primarily to lower benchmark WTI prices, partially offset by increased production. Oil Sands royalties are subject to completion of audits for 2009 and prior years. Changes to the estimated amounts previously recorded will be reflected in our financial statements on a prospective basis and may be significant. For a further discussion on Crown royalties, see pages 16 to 18.

Non-Cash Expenses

Non-cash expenses increased in 2009 as compared to 2008, primarily due to the addition of facilities for MacKay River and Syncrude as a result of the merger with Petro-Canada, as well as continued growth in the depreciable cost base after the commissioning of new assets throughout the year. Higher non-cash expenses decreased operating earnings by $185 million.

Tax Rate

As a result of decreases to the Oil Sands effective tax rate and taxable income in 2009 as compared to 2008, tax rate adjustments resulted in an increase to operating earnings of $94 million.

Cash Operating Costs

Cash operating costs (excluding Syncrude) increased to $3.599 billion in 2009, compared to $3.212 billion in 2008. On a per barrel basis, these costs decreased to $33.95 per barrel from $38.50 per barrel in 2008. The decrease in cash operating costs per barrel is a result of an increase in production and a decrease in natural gas input prices. These factors were partially offset by an increase in operational expenses due to the inclusion of operating costs from MacKay River as of August 1, 2009. Cash operating costs per barrel does not include costs related to deferral of growth projects.

Cash operating costs for our interest in Syncrude operations averaged $32.50 per barrel for the last five months of 2009. Users are cautioned that the Syncrude cash operating costs per barrel measure may not be fully comparable to similar information calculated by other entities (including Suncor's own cash operating costs per barrel excluding Syncrude) due to differing treatments for operating and capital costs among producers.

Refer to page 52 and 53 for further details on cash operating costs as a non-GAAP financial measure, including the calculation and reconciliation to GAAP measures.

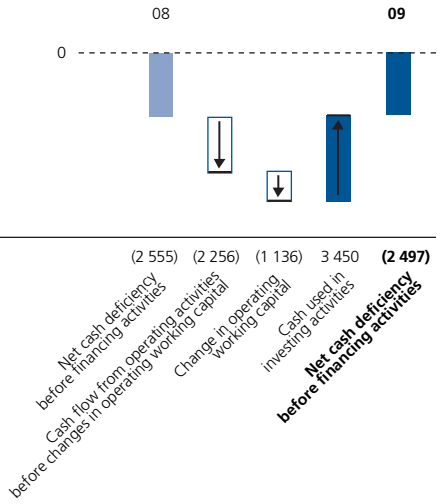
Net Cash Deficiency Analysis

Cash flow from operations was $1.251 billion in 2009, compared to $3.507 billion in 2008 (2007 – $3.165 billion). The decrease was primarily due to the same factors that impacted operating earnings.

Cash flow used in investing activities decreased to $3.546 billion in 2009 from $6.996 billion in 2008 (2007 – $4.248 billion). The decrease was primarily due to reduced capital spending resulting from the deferral of the company's growth projects in response to economic conditions. During 2009, capital spending related primarily to our Steepbank extraction plant and Firebag sulphur plant.

These were the primary factors that resulted in a net cash deficiency of $2.497 billion in 2009, compared with $2.555 billion in 2008 (2007 – net cash deficiency of $519 million).

Bridge Analysis of Oil Sands Net Cash Flow
($ millions)



Future Expansion

In January 2009, in response to market uncertainty, we deferred a number of our growth projects, pending construction restart. On November 13, 2009, Suncor's Board of Directors approved the 2010 capital budget, and we resumed construction on key growth projects.

The majority of our planned growth spending in 2010 will be directed toward the Firebag Stage 3 in-situ oil sands expansion, which was approximately 50 per cent complete before being deferred in early 2009. The project is now expected to begin production in the second quarter of 2011, with volumes then beginning to ramp up toward design capacity of approximately 68,000 barrels per day (bpd) of bitumen over a period of approximately 18 months. Spending will also be directed to Firebag Stage 4 to support a target of first bitumen production in the fourth quarter of 2012. Stage 4 also has a design capacity of 68,000 bpd. Remaining 2010 growth spending will be directed towards completion of a naphtha unit in one of our upgraders, which is intended to enhance product mix.

For further details, see the Significant Capital Project Update table on page 15.

The Oil Sands segment continued to incur costs related to placing certain growth projects into "safe mode" as a result of the company revising its 2009 capital budget due to market conditions earlier in the year. Safe mode is defined as the costs of deferring the projects and keeping the equipment and facilities in a safe manner in order to expedite remobilization. As a result of placing the company's Oil Sands projects into safe mode, pre-tax costs of $380 million were incurred in 2009. Further safe mode costs of $150 million to $200 million on a pre-tax basis, including costs related to remobilization of certain growth projects placed into safe mode, are expected to be incurred in 2010.

Planned Turnarounds

We have planned turnarounds scheduled for Upgrader 2 of approximately 45 days during the second quarter of 2010 and approximately 35 days during the third quarter of 2010.

February 2010 Fire

One of our oil sands upgraders was damaged by fire in early February. We have completed our assessment and repairs are currently underway. The company expects the damaged upgrader to return to production in early April 2010.

During the repair period, the company's second upgrader is expected to continue normal operations. Combined production of synthetic crude oil and bitumen sold directly to markets during this period is targeted at an average of approximately 210,000 barrels per day (bpd) in February and 230,000 bpd in March (these volumes do not include Suncor's proportionate production share from the Syncrude joint venture). Based on the damage assessment and repair schedule, and applicable waiting periods and deductibles, the company does not expect insurance to play a significant role in mitigating losses from this incident.

Risk Factors Affecting Performance

Our financial and operating performance is potentially affected by a number of factors, including, but not limited to, the following:

- Production reliability risk. Our ability to reliably operate our oil sands facilities in order to meet production targets.
- Our ability to finance oil sands growth and sustaining capital expenditures in a volatile commodity pricing environment. Also refer to Liquidity and Capital Resources on page 13.
- Bitumen supply. Ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage and in-situ reservoir and equipment performance could impact 2010 production targets.
- Performance of recently commissioned facilities. Production rates while new equipment is being lined out are difficult to predict and can be impacted by unplanned maintenance.
- Ability to manage production operating costs. Operating costs could be impacted by inflationary pressures on labour, volatile pricing for natural gas used as an energy source in oil sands processes, and planned and unplanned maintenance. We continue to address these risks through such strategies as application of technologies that help manage operational workforce demand, offsetting natural gas purchases through internal production, investigation of technologies that mitigate reliance on natural gas as an energy source, and an increased focus on preventative maintenance.
- Our ability to complete projects both on time and on budget. This could be impacted by competition from other projects (including other Oil Sands projects) for goods and services and demands on infrastructure in Fort McMurray and the surrounding area (including housing, roads and schools). We continue to address these issues through a comprehensive recruitment and retention strategy, working with the community to determine infrastructure needs, designing oil sands expansion to reduce unit costs, seeking strategic alliances with service providers and maintaining a strong focus on engineering, procurement and project management.
- Potential changes in the demand for refinery feedstock and diesel fuel. Our strategy is to reduce the impact of this issue by entering into long-term supply agreements with major customers, expanding our customer base and offering a variety of blends of refinery feedstock to meet customer specifications.
- Volatility in crude oil and natural gas prices, foreign exchange rates and the light/heavy and sweet/sour crude oil differentials. We mitigate some of the risk associated with changes in commodity prices through the use of derivative financial instruments (see page 20).
- Logistical constraints and variability in market demand, which can impact crude movements. These factors can be difficult to predict and control.
- Changes to royalty and tax legislation and related agreements that could impact our business. While fiscal regimes in Alberta and Canada are generally stable relative to many global jurisdictions, royalty and tax treatments are subject to periodic review, the outcome of which is not predictable and could result in changes to the company's planned investments, and rates of return on existing investments.
- Our relationship with our trade unions. Work disruptions have the potential to adversely affect oil sands operations and growth projects. The Communications, Energy and Paperworkers Union Local 707 represents approximately 2,900 Oil Sands employees. The current collective agreement with the union expires on April 30, 2010. Negotiations are ongoing.

Additional risks impacting Suncor's general operations can be seen at Risk Factors Affecting Performance on page 20. Additional risks, assumptions and uncertainties are discussed on page 54 under Forward-Looking Information.

NATURAL GAS

Suncor's Natural Gas business, operating primarily in Western Canada, acts as a natural price hedge against the company's purchases of natural gas for internal consumption.

Natural gas strategy focuses on:

- Upgrading our asset portfolio by divesting non-core conventional assets.
- Achieving a lower cost structure.
- Improving return on capital employed, with a focus on improved capital efficiency.
- Moving from an exploration to an execution focus in order to reliably and cost effectively manage our internal consumption.

HIGHLIGHTS

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	**2009 (1)**	2008	2007
Revenue (net of royalties)	**681**	579	427
Western Canada gross production (mmcfe/d)	**412**	220	215
U.S. Rockies gross production (mmcfe/d)	**34**	—	—
Western Canada average natural gas sales price ($/mcf)	**3.70**	8.23	6.32
U.S. Rockies average natural gas sales price ($/mcf)	**3.93**	—	—
Net earnings (loss)	**(199)**	89	25
Operating earnings (loss) (2)	**(187)**	89	(12)
Cash flow from operations (2), (3)	**329**	367	251
Cash used in investing activities	**(312)**	(316)	(532)
Total assets	**5 003**	1 862	1 811
ROCE (%) (2), (4)	**(8.4)**	7.7	2.5

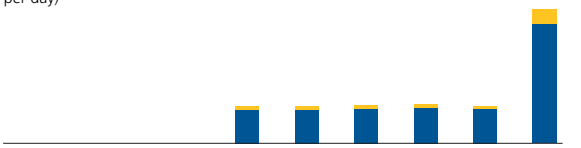
(1) Amounts for 2009 includes the results of five months of legacy Petro-Canada operations since the close of the merger on August 1, 2009.
(2) Non-GAAP measures. See pages 52 and 53.
(3) Calculation of this measure has been revised, and prior period comparative figures have been restated. See page 52.
(4) ROCE for Suncor operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non-GAAP Financial Measures.

2009 Overview

- Low benchmark prices significantly reduced Natural Gas price realizations in 2009. The average natural gas spot price at AECO was approximately 50% lower in 2009 than in 2008.
- Post-merger production from Suncor's Natural Gas business during the last five months of 2009 averaged 767 million cubic feet equivalent (mmcfe) per day, comprised of 88% natural gas and 12% natural gas liquids and crude oil. Production from legacy Suncor's natural gas operations averaged 210 mmcfe per day in 2009 compared to 220 mmcfe per day in 2008.
- Suncor has begun the process of divesting of a number of non-core natural gas assets.
  - On December 31, 2009, Suncor entered into an agreement to sell substantially all of its oil and gas producing assets in the U.S. Rockies for proceeds of $517 million (US$494 million) before closing adjustments. The effective close date of the sale was March 1, 2010.
  - On February 9, 2010, Suncor entered into an agreement to sell certain non-core natural gas properties located in northeast British Columbia for proceeds of $390 million. The sale is expected to close in March 2010 and is subject to customary closing conditions and regulatory approvals.

Total Production

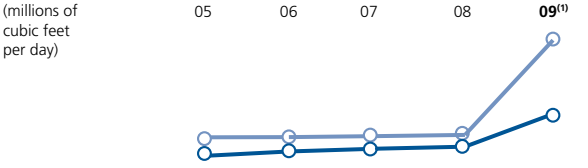
(millions of cubic feet equivalent per day)



	05	06	07	08	January to July 09	August to December 09 (1)
Natural gas liquids and crude oil	19	18	19	18	**18**	**90**
Natural gas	190	191	196	202	**195**	**677**
Total	209	209	215	220	**213**	**767**

Natural Gas Production vs. Purchases

(millions of cubic feet per day)



	05	06	07	08	09 (1)
Production	190	191	196	202	**677**
Purchases (2)	97	119	133	143	**309**

(1) Reflects only the results of the five months of operations after the merger with Petro-Canada on August 1, 2009.
(2) In 2009, purchases represent all internal consumption within our North American operations, while in prior periods purchases for internal consumption were for our oil sands operations only.

Operating Earnings[1]

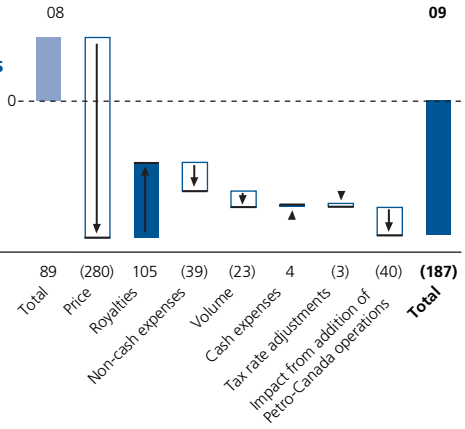
Year ended December 31 ($ millions, after-tax)	**2009**	2008	2007
Natural Gas net earnings (loss) as reported	**(199)**	89	25
Mark-to-market valuation of stock-based compensation	**11**	—	2
Impact of income tax rate adjustments on future income tax liabilities[2]	**1**	—	(39)
Natural Gas operating earnings (loss)	**(187)**	89	(12)

(1) Non-GAAP measure. See page 52 for a discussion of operating earnings.

(2) In the third quarter of 2009, an increase in future income tax liabilities resulted from a revised provincial allocation for income tax purposes due to the merger with Petro-Canada. This was partially offset for the year ended December 31, 2009 by a reduction to the Ontario income tax rate in the fourth quarter of 2009, resulting in a decrease in future income tax liabilities. See note 7 to the Consolidated Financial Statements.

Natural Gas recorded a net loss of $199 million in 2009, compared to net earnings of $89 million in 2008 (2007 – net earnings of $25 million). The operating loss was $187 million in 2009, compared to operating earnings of $89 million in 2008 (2007 – operating loss of $12 million). The decrease in earnings was primarily due to significantly lower benchmark commodity prices, higher operating, selling and general and depreciation, depletion and amortization expense resulting from the merger with Petro-Canada, decreased legacy Suncor production due to shut-in volumes in the Elmworth area and the sale of certain non-core assets in the second quarter of 2009, lower sulphur revenue and higher dry hole costs. This was partially offset by lower royalty expense in 2009 compared to 2008 as a result of lower revenues, royalty credits and reduced rates due to the implementation of the Alberta New Royalty Framework.

Bridge Analysis of Natural Gas Operating Earnings
($ millions)



The average realized price for natural gas was $3.71 per thousand cubic feet (mcf) in 2009, compared to an average of $8.23 per mcf in 2008, reflecting significantly lower benchmark natural gas prices. There was also a decrease in price realizations for crude oil and natural gas liquids, as well as sulphur, resulting from lower benchmark prices for those products in 2009. The net impact of the price variance was a decrease in operating earnings of $280 million.

Natural Gas Production

Year ended December 31 Average mmcfe per day	**09**	08	07	06	05
Legacy Suncor operations	**210**	220	215	209	209

Average mmcfe per day	**2009[1]**
Legacy Petro-Canada Western Canada	**482**
Legacy Petro-Canada U.S. Rockies	**80**
Total legacy Petro-Canada Natural Gas production	**562**

(1) Production for 2009 is only the results of five months of operations since the merger with Petro-Canada on August 1, 2009

After completion of the merger with Petro-Canada, Suncor's natural gas production during the last five months of 2009 averaged 767 million cubic feet equivalent (mmcfe) per day, comprised of 88% natural gas and 12% natural gas liquids and crude oil. Production from legacy Suncor's natural gas operations averaged 210 mmcfe per day in 2009 compared to 220 mmcfe per day in 2008 which decreased primarily due to shut-in production in the Elmworth area as a result of low commodity prices and the sale of certain non-core assets during the second quarter of 2009.

Cash Expenses

Cash expenses decreased in 2009 as compared to 2008, primarily due to lower production from our legacy Suncor natural gas operations. Overall, decreased cash expenses increased operating earnings by $4 million.

Lifting and Administration Costs

($/mcfe)	05	06	07	08	**09[1]**
Administration	0.42	0.67	0.70	0.56	**0.53**
Lifting	0.86	0.91	1.26	1.38	**1.35**
Total	1.28	1.58	1.96	1.94	**1.88**

(1) Amounts for 2009 includes the results of five months of legacy Petro-Canada operations since the close of the merger on August 1, 2009.

Non-Cash Expenses

Non cash expenses increased in 2009 as compared to 2008, primarily due to higher dry hole costs in 2009. Overall, increased non-cash expenses decreased operating earnings by $39 million.

Royalties

Royalties on production of natural gas, liquids and sulphur were $85 million ($0.53 per thousand cubic feet equivalent (mcfe)) in 2009, a decrease from $175 million

($2.17 per mcfe) in 2008 (2007 – $126 million; $1.61 per mcfe). The decrease in royalty expense for the year was due to significantly lower benchmark commodity prices, royalty credits and reduced rates due to the implementation of the Alberta New Royalty Framework, which was partially offset by increased royalty expense as a result of the merger. For a further discussion on Crown royalties, see page 18.

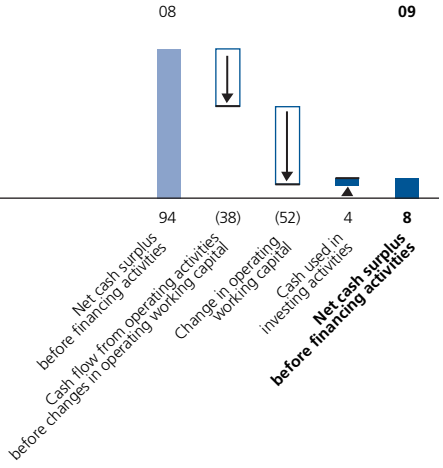
Overall, decreased royalties increased operating earnings by $105 million.

Net Cash Surplus (Deficiency) Analysis

Natural Gas net cash surplus was $8 million in 2009, compared with $94 million in 2008 (2007 – net cash deficiency of $262 million). Cash flow from operations decreased to $329 million, compared with $367 million in 2008 (2007 – $251 million), impacted by the same factors that affected net earnings, excluding the impact of dry hole costs.

Cash used in investing activities decreased to $312 million, compared with $316 million in 2008 (2007 – $532 million) primarily due to a decrease in drilling activity in 2009, partially offset by the inclusion of five months of Petro-Canada results.

Bridge Analysis of Natural Gas Net Cash Flow
($ millions)



Risk Factors Affecting Performance

Our financial and operating performance is potentially affected by a number of factors, including, but not limited to, the following:

- Consistently and competitively finding and developing reserves that can be brought on stream economically.
- Our ability to finance capital investment to replace reserves or increase processing capacity in a volatile commodity pricing and credit environment. Also refer to Liquidity and Capital Resources on page 13.
- Volatility in natural gas and liquids prices is not predictable and can significantly impact revenues.
- The accessibility and cost of mineral rights. Market demand influences the cost and available opportunities for mineral leases and acquisitions.
- Risk associated with a depressed market for asset sales, leading to losses on disposition.
- Risk in our ability to successfully change focus from a conventional to unconventional gas producer.
- Risks and uncertainties associated with consulting with stakeholders and obtaining regulatory approval for exploration and development activities in our operating areas. These risks could increase costs and/or cause delays to or cancellation of projects.
- Risks and uncertainties associated with weather conditions, which can shorten the winter drilling season and impact the spring and summer drilling program, which may result in increased costs and/or delays in bringing on new production.

Additional risks impacting Suncor's general operations can be seen at Risk Factors Affecting Performance on page 20. Additional risks, assumptions and uncertainties are discussed on page 54 under Forward-Looking Information.

EAST COAST CANADA

Suncor has a strong position in every major producing oil development off Canada's east coast. The company holds a 20% interest in Hibernia, a 27.5% interest in White Rose* and a 22.7% interest in Hebron, and is the operator of Terra Nova with a 34%** interest.

The East Coast Canada strategy focuses on:

- Delivering top quartile operating performance and maximizing cash flow.
- Sustaining profitable production through reservoir extensions and add-ons.
- Pursuing high potential, near field development and exploration projects.

HIGHLIGHTS

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	2009 (1)
Revenue (net of royalties)	**441**
Production (bpd)	**58 000**
Average sales price ($/bbl)	**76.86**
Net earnings	**112**
Operating earnings (2)	**111**
Cash flow from operations (2)	**335**
Total assets	**4 771**
Cash used in investing activities	**(152)**
ROCE (%) (2), (3)	**10.7**
ROCE (%) (2), (4)	**6.5**

(1) Reflects the results of operations since the merger with Petro-Canada on August 1, 2009.
(2) Non-GAAP measures. See pages 52 and 53.
(3) Excludes capitalized costs related to major projects in progress. Return on capital employed (ROCE) for our operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non-GAAP Financial Measures.
(4) Includes capitalized costs related to major projects in progress.

2009 Overview

- Total production volume averaged 58,000 bpd in the last five months of 2009. Production was lower than capacity as a result of planned and unplanned maintenance, including the successful completion of the subsea tie-in of the North Amethyst extension at White Rose.
- Average crude sales price was $76.86 per barrel during the last five months of 2009. Sales price realizations were negatively impacted by low benchmark prices.

Operating Earnings (1)

Year ended December 31 ($ millions, after-tax)	2009 (1)
East Coast Canada net earnings as reported	**112**
Mark-to-market valuation of stock-based compensation	**2**
Impact of income tax rate reductions on opening future income tax liabilities (2)	**(20)**
Impact of recording acquired inventory at fair value (3)	**17**
East Coast Canada operating earnings	**111**

(1) Non-GAAP measure. See page 52 for a discussion of operating earnings.
(2) In the fourth quarter of 2009, a decrease in the future income tax liabilities resulted from a reduction to the Ontario income tax rate. See note 7 to the Consolidated Financial Statements.
(3) Inventory acquired through the merger at fair value was sold during 2009, resulting in a one-time negative impact to earnings.

Net earnings for East Coast Canada were $112 million in 2009, while operating earnings for 2009 were $111 million. Lower than capacity production as a result of planned and unplanned maintenance, as well as the tie-in of the North Amethyst extension at White Rose, adversely impacted earnings in the period.

East Coast Canada Net Production (1)

Five months ended December 31 Barrels per day	2009
Terra Nova	**20 800**
Hibernia	**27 200**
White Rose	**10 000**
Total East Coast Canada net production	**58 000**

(1) Production since the close of the merger on August 1, 2009

In the five months ended December 31, 2009, East Coast Canada production averaged 58,000 bpd. Terra Nova production averaged 20,800 bpd, with production impacted by planned and unplanned maintenance during August, September and early October. Production from Hibernia averaged 27,200 bpd for the five months ended December 31, 2009, with strong reservoir capability and facility reliability in the period. White Rose production averaged 10,000 bpd during the five months ended December 31, 2009, with production negatively impacted by planned downtime for maintenance and the tie-in of the North Amethyst extension during the period.

* Suncor holds a 26.125% interest in the White Rose North Amethyst and West White Rose extensions.

** Under the Terra Nova Development and Operating Agreement, a redetermination of working interests is required following payout. The owners have been working through a process to redetermine what the future working interests will be. This process is ongoing.

Sales volumes in the five months ended December 31, 2009 averaged 58,000 bpd, impacted by the same factors affecting production, and average realized crude oil price was $76.86 per barrel.

Non-cash expenses were impacted by an increase in the depreciable asset base for Hibernia, White Rose and Terra Nova as a result of the fair value allocation upon merger. Cash expenses were in line with expectations for the period.

Royalties

East Coast Canada royalties were $217 million ($23.82 per barrel) in 2009, averaging 33% of gross revenue. Terra Nova production was subject to a Tier I royalty of 30% of net revenue and a Tier II royalty of an incremental 12.5% of net revenue. White Rose production was subject to a Tier I royalty of 20% of net revenue and a Tier II royalty of 10% of net revenue. The royalty rate on Hibernia production increased from 5% of gross revenue to 30% of net revenue during 2009 based on the terms of the Hibernia Royalty Agreement and a Memorandum of Understanding. In addition, Hibernia production was subject to a federal government net profits interest of up to 10% of net revenue.

For a further discussion on Crown royalties, see page 18.

Net Cash Surplus Analysis

East Coast Canada's net cash surplus was $149 million in 2009. Cash flow from operations was $335 million in 2009, impacted by the same factors affecting earnings. Cash used in investing activities was $152 million primarily due to work performed on East Coast Canada growth projects, including the North Amethyst and Hibernia South extension projects.

Growth Update

Installation of subsea infrastructure is complete and development drilling continues for the North Amethyst portion of the White Rose Extensions, with first oil targeted during the second quarter of 2010. Development drilling of North Amethyst will continue through 2012.

Preliminary engineering and design activities continued for the Hebron project during 2009.

Drilling commenced during 2009 on the Hibernia South Extension project, in which the company holds a 19.5% interest, with production expected to begin in the first quarter of 2010. Final fiscal agreements were made between co-venturers and the Government of Newfoundland and Labrador in February 2010.

For further details, see the Significant Capital Project Update table on page 15.

Planned Turnarounds

During the second quarter of 2010, we have planned turnarounds scheduled of approximately 18 days for Terra Nova and 12 days for Hibernia. In addition, we have a planned turnaround scheduled for White Rose of approximately 20 days during the third quarter of 2010 and a planned turnaround during the fourth quarter of 2010 of approximately 10 days scheduled for Terra Nova.

Risk Factors Affecting Performance

Our financial and operating performance is potentially affected by a number of factors, including, but not limited to, the following:

- Consistently and competitively finding and developing reserves that can be brought on stream economically.
- Volatility in crude oil prices is not predictable and can significantly impact revenues.
- Performance after completion of maintenance not predictable and can significantly impact production rates.
- Risks and uncertainties associated with consulting with stakeholders and obtaining regulatory approval for exploration and development activities. These risks could increase costs and/or cause delays to or cancellation of projects and expansions to existing projects.
- Risks and uncertainties associated with weather conditions, which may result in increased costs and/or delays in bringing on new production.
- Our ability to finance capital investment to replace reserves or increase processing capacity in a volatile commodity pricing and credit environment. Also refer to Liquidity and Capital Resources on page 13.
- Risks associated with applicable legal and other regulatory requirements, including changes to tax, environmental and other legal and regulatory requirements, the outcome of which is not predictable and could result in changes to the company's planned investments, and rates of return on the company's existing investments.

Additional risks impacting Suncor's general operations can be seen at Risk Factors Affecting Performance on page 20. Additional risks, assumptions and uncertainties are discussed on page 54 under Forward-Looking Information.

INTERNATIONAL

Suncor has International activities in two core areas: the North Sea (the United Kingdom (U.K.), the Netherlands and Norway sectors) and Other International areas (Libya, Syria, and offshore Trinidad and Tobago).

The International strategy focuses on:

- Delivering top quartile operating performance and maximizing cash flow.
- Sustaining profitable production through reservoir extensions and add-ons.
- Pursuing high potential, near field development and exploration projects.
- Divesting non-core North Sea assets (The Netherlands and other U.K.), as well as Trinidad and Tobago.

HIGHLIGHTS

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	2009 (1)
Revenue (net of royalties)	**1 183**
North Sea net production (boe/d)	**76 500**
Other International net production (boe/d)	**44 300**
Average North Sea sales price ($/bbl)	**71.63**
Average Other International sales price ($/boe)	**61.25**
Net earnings	**165**
Operating earnings (2)	**223**
Cash flow from operations (2)	**616**
Total assets	**9 913**
Cash used in investing activities	**(483)**
ROCE (%) (2), (3)	**11.5**
ROCE (%) (2), (4)	**7.5**

(1) Reflects the results of operations since the merger with Petro-Canada on August 1, 2009.

(2) Non-GAAP measures. See pages 52 and 53.

(3) Excludes capitalized costs related to major projects in progress. Return on capital employed (ROCE) for our operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non-GAAP Financial Measures.

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

2009 Overview

- Net production volumes averaged 120,800 boe per day in the last five months of 2009.
- Production in the North Sea was lower than capacity as a result of planned maintenance shutdowns. After completion of the shutdown at the Buzzard development in the third quarter of 2009, production did not return to full production capacity as quickly as planned, but this development was back operating at expected capacity by year-end.
- Production in Libya was adversely impacted by OPEC production quota constraints.
- Average sales price in the last five months of 2009 was $71.63 per barrel for the North Sea, and $61.25 per boe for Other International. The combined average sales price for the International segment in this period was $67.82 per boe.
- Suncor has announced plans to divest of a number of non-core assets from the International segment. The proposed divestments identified to date include all Trinidad and Tobago assets and certain non-core North Sea assets, including all assets in The Netherlands.

Operating Earnings (1)

Year ended December 31 ($ millions, after-tax)	2009
International net earnings as reported	**165**
Mark-to-market valuation of stock-based compensation	**8**
Impact of recording acquired inventory at fair value (2)	**8**
Losses and adjustments on significant disposals (3)	**42**
International operating earnings	**223**

(1) Non-GAAP measure. See page 52 for a discussion of operating earnings.

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

(3) Fair value adjustments to assets acquired in the merger with Petro-Canada.

Net earnings for International were $165 million in the five months ended December 31, 2009, while operating earnings for the same period were $223 million. Lower than capacity production as a result of planned and unplanned maintenance, as well as OPEC quota constraints, adversely impacted earnings in the period. These factors were partially offset by improved price realizations.

International Net Production[1]

Five months ended December 31 Boe per day	2009
U.K. sector of the North Sea	**63 300**
The Netherlands sector of the North Sea	**13 200**
North Sea	**76 500**
Other International	**44 300**
Total International net production	**120 800**

(1) Production since the close of the merger with Petro-Canada on August 1, 2009

International net production averaged 120,800 boe per day in the five months ended December 31, 2009. Net production from the Buzzard development in the U.K. sector of the North Sea averaged 47,800 boe per day in the same period, impacted by a planned four-week shutdown during the third quarter of 2009. In the Netherlands sector of the North Sea, production was 13,200 boe per day for the five months ended December 31, 2009.

Other International consists of producing assets in Libya and Trinidad and Tobago. Production in Libya averaged 32,600 boe per day in the five months ended December 31, 2009, with production impacted by OPEC production quota constraints. Trinidad and Tobago offshore gas production averaged 11,700 boe per day in the same period, with high demand from the Atlantic liquefied natural gas terminal.

The average sales price for North Sea production was $71.63 per barrel in the five months ended December 31, 2009, while the average sales price for Other International was $61.25 per barrel of oil equivalent.

During 2009, planned maintenance shutdowns occurred at the Buzzard and Hanze facilities in the North Sea, resulting in reduced production. In late September 2009, planned turnaround and maintenance commenced at the Triton facility in the U.K. sector of the North Sea and was completed in early October, affecting overall production in 2009.

Cash Expenses

Cash expenses for 2009 were impacted by maintenance expenses incurred in the period, as well as the continued seismic program in Libya.

Non-Cash Expenses

Non-cash expenses were impacted by an increase in the depreciable base for assets as a result of the fair value allocation upon merger and dry hole costs incurred in the U.K. and The Netherlands.

Net Cash Surplus Analysis

International's net cash surplus was $98 million in 2009. Cash flow from operations was $616 million in 2009, impacted by the same factors affecting earnings. Cash used in investing activities was $483 million primarily due to work performed to advance International growth projects, including the Buzzard Enhancement project and Ebla Gas project.

Growth Update

Syria

The Ebla Gas Project remains on plan for first gas delivery in mid 2010 and was 90% complete at the end of 2009. Five gas wells have been completed and are ready for production. The 3D seismic acquisition of the Cherrife field was completed during the third quarter of 2009 and is currently being interpreted, while the 3D seismic survey of the Ash Shaer field was completed during the second quarter of 2009 and is also now being interpreted.

For further details, see the Significant Capital Project Update table on page 15.

Libya

Work has commenced on implementing the projects associated with the Libya Exploration and Production Sharing Agreements (EPSAs), with a focus on preparing the EPSA field development programs and progressing with the new exploration program. Work on the exploration program is progressing, with seven seismic surveys completed in 2009 and two seismic crews continue to acquire data in country. Seismic surveys completed in 2009 are being processed. Drilling of the first exploration well is expected to commence early in the second quarter of 2010.

Planned International Divestments

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

On February 25, 2010, Suncor entered into an agreement to sell its assets in Trinidad and Tobago for proceeds of $396 million (US$380 million). The sale is expected to close in March 2010 and is subject to customary closing conditions, Trinidad and Tobago government approval and other regulatory approvals.

Planned Turnarounds

During the second quarter of 2010, we have planned turnarounds of approximately 14 days for Buzzard, 14 days for Triton, 14 days for De Ruyter and 7 days for Hanze. In the third quarter of 2010, we have scheduled planned turnarounds of approximately 21 days for Triton and 7 days for Buzzard.

Risk Factors Affecting Performance

Our financial and operating performance is potentially affected by a number of factors, including, but not limited to, the following:

- Consistently and competitively finding and developing reserves that can be brought on stream economically.
- Volatility in commodity prices is not predictable and can significantly impact revenues. Current commodity prices are well below the average price realized in the last three years.
- Risks and uncertainties associated with consulting with stakeholders and obtaining regulatory approval for exploration and development activities in our operating areas. These risks could increase costs and/or cause delays to or cancellation of projects.
- Risks and uncertainties associated with operations in a number of foreign countries with different political, taxation, economic and social systems. These risks could decrease revenue, increase costs and/or cause delays to or nationalization, expropriation or cancellation of production and/or projects.
- Our ability to finance capital investment to replace reserves or increase processing capacity in a volatile commodity pricing and credit environment. Also refer to Liquidity and Capital Resources on page 13.
- Risks associated with applicable legal and other regulatory requirements, including changes to tax, environmental and other legal and regulatory requirements, the outcome of which is not predictable and could result in changes to the company's planned investments, and rates of return on the company's existing investments.

Additional risks impacting Suncor's general operations can be seen at Risk Factors Affecting Performance on page 20. Additional risks, assumptions and uncertainties are discussed on page 54 under Forward-Looking Information.

REFINING AND MARKETING

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

- Enhancing the profitability of refining operations by improving reliability, product yields and enhancing operational flexibility to process a variety of feedstock, including crude oil streams from oil sands operations.
- Creating downstream market opportunities to capture greater long-term value from oil sands production.
- Increasing the profitability of our retail and wholesale networks.

HIGHLIGHTS

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	**2009**	2008	2007
Revenue	**12 013**	9 419	8 391
Refined product sales (millions of litres)			
Gasoline	**9 975**	5 819	6 132
Total	**19 672**	11 529	12 228
Net earnings (loss)	**433**	(5)	442
Operating earnings breakdown:			
Refining and product supply	**347**	(43)	396
Marketing	**152**	37	36
Total operating earnings (loss)[1]	**499**	(6)	432
Cash flow from operations[1],[2]	**963**	248	711
Total assets	**10 568**	4 687	4 846
Cash used in investing activities	**(391)**	(256)	(491)
ROCE (%)[1],[3]	**7.5**	1.8	20.0
ROCE (%)[1],[4]	**7.5**	1.8	17.4

(1) Non-GAAP measures. See pages 52 and 53.

(2) Calculation of this measure has been revised, and prior period comparative figures have been restated. See page 52.

(3) Excludes capitalized costs related to major projects in progress. Return on capital employed (ROCE) for our operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non-GAAP Financial Measures. Prior years have not been restated for the movement of energy trading activities to Corporate, Energy Trading and Eliminations.

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

2009 Overview

- Strong operational and positive financial performance despite a softening demand for petroleum products during 2009 as a result of poor economic conditions.
- After completion of the merger with Petro-Canada, Suncor's total sales of refined petroleum products during the last five months of 2009 averaged 84.8 million litres per day, including additional sales of 53.1 million litres per day resulting from the merger.
- Significant increase in refined product sales due to the addition of the Edmonton and Montreal refineries, national retail and wholesale businesses, and an international lubricants business as a result of the merger with Petro-Canada.
- The observed performance of our Edmonton refinery in 2009, after improvements completed in previous years, has enabled us to upwardly revise our nameplate capacity to 135,000 bpd from the previously disclosed 125,000 bpd. Starting January 1, 2010, refinery utilization will be calculated using the 135,000 bpd capacity.

Operating Earnings[1]

Year ended December 31 ($ millions, after-tax)	**2009**	2008	2007
Refining and Marketing net earnings (loss) as reported	**433**	(5)	442
Mark-to-market valuation of stock-based compensation	**17**	(1)	7
Impact of income tax rate reductions on opening future income tax liabilities[2]	**(19)**	—	(17)
Costs related to deferral of growth projects	**1**	—	—
Impact of recording acquired inventory at fair value[3]	**67**	—	—
Refining and Marketing operating earnings (loss)	**499**	(6)	432

(1) Non-GAAP measure. See page 52 for a discussion of operating earnings.

(2) In the fourth quarter of 2009, a decrease in the future income tax liabilities resulted from a reduction to the Ontario income tax rate. See note 7 to the Consolidated Financial Statements.

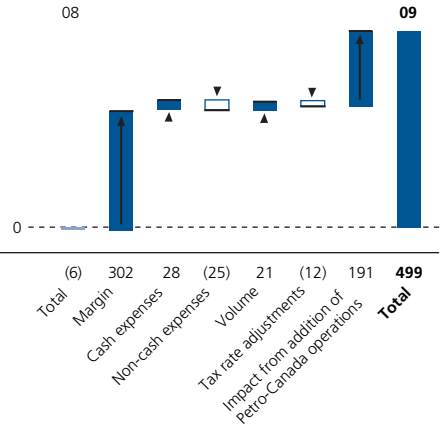
(3) Inventory acquired through the merger at fair value was sold during the third quarter of 2009, resulting in a one-time negative impact to earnings.

Refining and Marketing's net earnings increased to $433 million in 2009 from a net loss of $5 million in 2008 (2007 – net earnings of $442 million). Operating earnings were $499 million in 2009, compared to an operating loss of $6 million in 2008 (2007 – operating earnings of $432 million). The increase in earnings was primarily due to improved operational reliability at our existing Sarnia and Commerce City refineries that resulted in higher gross margins in 2009, compared to 2008 and the addition of assets associated with the company's merger with Petro-Canada in the third quarter of 2009, partially offset by the impact of lower overall demand for refined petroleum products associated with general economic conditions.

Refining and product supply contributed operating earnings of $347 million in 2009, up from an operating loss of $43 million in 2008. The increase was due to improved operational reliability at our existing Sarnia and Commerce City refineries and increased production resulting from the addition of the Edmonton and Montreal refineries, and the lubricants plant, as a result of the merger. These factors were partially offset by the impact of a weak business environment in 2009, resulting in softening demand for refined petroleum products.

Marketing contributed operating earnings of $152 million in 2009, up from $37 million in 2008, despite a weak business environment. The increase was due to the addition of the national Retail and Wholesale operations and the lubricants business as a result of the merger with Petro-Canada during the third quarter of 2009.

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



Volumes

After completion of the merger with Petro-Canada, Suncor's total sales of refined petroleum products during the last five months of 2009 averaged 84.8 million litres per day, including additional sales of 53.1 million litres per day resulting from the merger. Despite sales growth being constrained in 2009 by current economic conditions, total sales of refined petroleum products from legacy Suncor's refining and marketing operations averaged 32.6 million litres per day in 2009, compared to 31.5 million litres per day in 2008 reflecting improved refinery reliability.

Fuel Margins

Improved operational reliability at our existing Sarnia and Commerce City refineries resulted in higher gross margins in 2009, compared to 2008, as we were able to process more crude rather than purchasing refined product to meet customer commitments, which negatively impacted our margins in the comparative period.

Cash and Non-Cash Expenses

Cash expenses decreased $28 million in 2009, primarily due to lower input energy costs, as well as lower maintenance at the Sarnia and Commerce City refineries due to improved refinery reliability. Non-cash expenses increased by $25 million in 2009, primarily due to increased depreciation associated with recently completed projects and the cancellation of other partially completed projects. Overall, lower cash and non-cash expenses increased operating earnings by $3 million in 2009.

Refinery Utilization

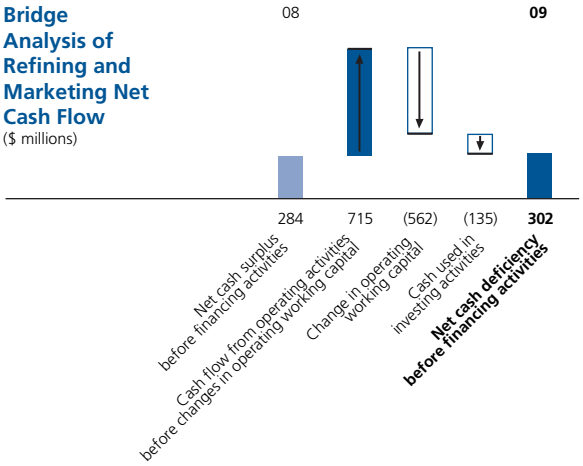
Overall crude refinery utilization averaged 92% in 2009, with utilization for the legacy Suncor refineries averaging 96% compared to 97% in 2008. Although average utilization for the legacy Suncor refineries was down slightly from 2008, this was primarily due to an increase in capacity for both refineries effective January 1, 2009, offset by an increase in processed crude oil as a result of improved operational reliability.

Net Cash Surplus (Deficiency) Analysis

Refining and Marketing's net cash surplus was $302 million in 2009 compared to $284 million in 2008 (2007 – deficiency of $27 million). Cash flow from operations was $963 million in 2009 compared to $248 million in 2008 (2007 – $711 million). The decrease was primarily due to the same factors that impacted net earnings.

Cash used in investing activities was $391 million in 2009 compared to $256 million in 2008 (2007 – $491 million). The increase was due primarily to the addition of the Montreal and Edmonton refineries and lubricants plant as a result of the merger, as well as spending on sustaining and growth projects at our legacy Suncor refineries in 2009.

Bridge Analysis of Refining and Marketing Net Cash Flow
($ millions)



Risk Factors Affecting Performance

Our financial and operating performance is potentially affected by a number of factors, including, but not limited to, the following:

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

Additional risks impacting Suncor's general operations can be seen at Risk Factors Affecting Performance on page 20. Additional risks, assumptions and uncertainties are discussed on page 54 under Forward-Looking Information.

CORPORATE, ENERGY TRADING AND ELIMINATIONS

Corporate, Energy Trading and Eliminations includes third-party energy supply and trading activities and activities not directly attributable to an operating segment. It also supports Suncor's sustainability goals by managing investment in wind energy projects and developing strategies to reduce greenhouse gas emissions.

Operating Earnings[1]

Year ended December 31 ($ millions, after-tax)	**2009**	2008	2007
Net earnings (loss) as reported	**78**	(822)	42
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(798)**	852	(215)
Mark-to-market valuation of stock-based compensation	**58**	(101)	(1)
Impact of income tax rate adjustments on future income tax liabilities[2]	**5**	—	42
Merger and integration costs	**151**	—	—
Operating loss	**(506)**	(71)	(132)

(1) Non-GAAP measure. See page 52 for a discussion of operating earnings.

(2) In the third quarter of 2009, an increase in the future income tax liabilities resulted from a revised provincial allocation for income tax purposes due to the merger with Petro-Canada. This was partially offset for the year ended December 31, 2009 by a reduction to the Ontario income tax rate in the fourth quarter of 2009, resulting in a decrease in the future income tax liabilities. See note 7 of the Consolidated Financial Statements.

Corporate, Energy Trading and Eliminations net earnings were $78 million in 2009, compared to a net loss of $822 million in 2008 (2007 – net earnings of $42 million). Corporate, Energy Trading and Eliminations recorded an operating loss of $506 million in 2009, compared to $71 million in 2008 (2007 – $132 million). Results reflected higher net interest expense in 2009 due to additional debt acquired through the merger with Petro-Canada and $437 million of interest costs on debt used to finance growth projects. In 2009, these interest costs were expensed while growth projects were in safe mode, compared to 2008 when interest expense was capitalized. In addition, 2009 results reflected lower energy supply and trading earnings and an increase in profits eliminated on crude oil sales between upstream segments and Refining and Marketing, where this crude oil still resides in Refining and Marketing's inventories.

Summary of Results

Year ended December 31 ($ millions)	**2009**	2008	2007
Net earnings (loss)	**78**	(822)	42
Operating loss			
Corporate	**(457)**	(118)	(138)
Energy supply and trading	**44**	56	9
Group eliminations	**(93)**	(9)	(3)
Total operating loss	**(506)**	(71)	(132)
Cash flow used in operations	**(695)**	(65)	(90)
Total assets	**1 938**	184	(320)
Cash from (used in) investing activities	**213**	(22)	(91)
Renewable energy net earnings	**28**	28	31

Energy Supply and Trading Activities

Year ended December 31 ($ millions unless otherwise noted)	**2009**	2008	2007
Settlement of non-trading physical contracts	**8 008**	11 295	2 931
Settlement of trading physical contracts	**20**	—	—
Gains (losses) on trading derivatives	**(70)**	127	(39)
Gains on inventory valuation	**47**	—	—
Energy Supply and Trading Activities Revenue	**8 005**	11 422	2 892
Settlement of non-trading physical contracts	**(7 929)**	(11 331)	(2 871)
Operating, selling & general expense	**(13)**	(11)	(10)
Energy Supply and Trading Activities Earnings (pre-tax)	**63**	80	11

These activities involve marketing and trading of crude oil, natural gas, refined products and by-products, and the use of financial derivatives. These activities resulted in pre-tax earnings of $63 million in 2009 compared to $80 million in 2008 (2007 – $11 million). Marketing and trading profits were generated primarily by transporting crude oil to more attractive markets and by holding crude oil in storage to realize higher future prices. The lower earnings in 2009 are primarily attributable to financial derivatives designed to protect the value of physical positions. A portion of the gains on financial derivatives realized in 2008, on a fair value basis, are offset by losses on the physical positions realized in 2009. For further details on our energy supply and trading activities, see page 19.

Renewable Energy

Our renewable energy interests include four wind power projects and Canada's largest ethanol plant by production volume. Net earnings from renewable energy were $28 million in 2009, compared to $28 million in 2008 (2007 – $31 million).

Our four wind projects, located in Saskatchewan, Alberta and Ontario, have a total generating capacity of 147 megawatts, offsetting the equivalent of 284,000 tonnes of carbon dioxide (CO_2) per year.

The St. Clair Ethanol Plant has a current capacity of 200 million litres per year, offsetting the equivalent of 300,000 tonnes of CO_2 per year. A $120 million expansion of the ethanol plant currently underway, estimated to be completed in the first quarter of 2011, is expected to double the production capacity.

OUTLOOK

During 2010, management will focus on the following priorities:

- **Operational excellence.** Focusing on operational excellence to enhance personal and process safety management, environmental excellence and sustainability, reliability, and people.
- **Continue to focus on safety.** Continue efforts to identify and reduce potential process safety hazards and implement enhanced company-wide occupational hygiene and health standards.
- **Strengthen balance sheet.** Planned capital spending has been set at $5.5 billion for 2010, with expected near-term cash flow from operations as key criteria for investment. Applying proceeds from planned divestitures to reduce net debt is expected to contribute to a target of two-times cash flow from operations.
- **Continue efforts to reduce environmental impact intensity.** We expect to reclaim the industry's first tailings pond to a trafficable surface. As well, work will continue on developing accelerated reclamation technology.

Update to Production Outlook Issued February 4, 2010

One of our oil sands upgraders was damaged by fire in February 2010. Repairs are currently underway and the company expects the damaged upgrader to return to production in early April 2010.

During the repair period, the company's second upgrader is expected to continue normal operations. Combined production of synthetic crude oil and bitumen sold directly to markets during this period is targeted at an average of approximately 210,000 barrels per day (bpd) in February and 230,000 bpd in March (these volumes do not include Suncor's proportionate production share from the Syncrude joint venture). Accordingly, Suncor's production outlook issued on February 4, 2010 will be impacted and will be updated with the release of the company's first quarter results on May 4, 2010.

This update contains forward-looking statements identified by the word "targeted" and similar expressions that address expectations or projections about the future. Forward-looking statements are based on Suncor's current goals, expectations, estimates, projections and assumptions made in light of its experiences and the risks, uncertainties and other factors related to its business. Assumptions used to develop our production targets and outlook are based on year-to-date performance and management's best estimates for the remainder of the year.

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

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

For additional information on risk factors that could cause actual results to differ, please see page 20.

NON-GAAP FINANCIAL MEASURES

Certain financial measures referred to in this MD&A are not prescribed by Canadian generally accepted accounting principles (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. We include cash flow from operations (dollars and per share amounts), return on capital employed (ROCE), 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 Canadian GAAP.

Operating Earnings

Operating earnings (loss) represent net earnings (loss) excluding the change in fair value of commodity derivatives used for risk management purposes, unrealized foreign exchange gain (loss) on U.S. dollar denominated long term debt, mark-to-market valuation of stock-based compensation, impact of income tax rate adjustments on future income tax liabilities, costs related to start-up or deferral of growth projects, and impacts related to the merger with Petro-Canada. Operating earnings are used by the Company to evaluate operating performance. See page 12 for a reconciliation of consolidated net earnings to consolidated operating earnings.

Cash Flow from Operations per Common Share

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

For the year ended December 31	**2009**	2008	2007
Cash flow from operations ($ millions)	**2 799**	4 057	4 037
Weighted number of shares outstanding – basic (millions of shares)	**1 198**	932	922
Cash flow from operations – basic ($ per share)	**2.34**	4.36	4.38

ROCE

For the year ended December 31 ($ millions, except ROCE)		2009	2008	2007
Adjusted net earnings				
Net earnings		**1 146**	2 137	2 983
Add: after-tax financing expenses (income)		**(509)**	852	(179)
	A	**637**	2 989	2 804
Capital employed – beginning of year				
Short-term and long-term debt, less cash and cash equivalents		**7 226**	3 248	1 849
Shareholders' equity		**14 523**	11 896	9 084
	B	**21 749**	15 144	10 933
Capital employed – end of year				
Short-term and long-term debt, less cash and cash equivalents		**13 377**	7 226	3 248
Shareholders' equity		**34 111**	14 523	11 896
	C	**47 488**	21 749	15 144
Average capital employed (1)	D	**35 128**	18 447	13 039
Average capitalized costs related to major projects in progress	E	**10 655**	5 149	3 454
ROCE (%) (2)	A/(D – E)	**2.6**	22.5	29.3

(1) Average capital employed for 2008 and 2007 is calculated on a simple-average basis (B+C)/2. In 2009, as a result of the significant capital employed that was acquired during the year due to the merger with Petro-Canada, average capital employed is now calculated on a monthly weighted-average basis.

(2) The increase in capital employed as a result of the merger with Petro-Canada has caused our return on capital employed measure to decrease significantly, as the calculation only includes five months of results relating to legacy Petro-Canada operations.

Oil Sands Operating Costs – Total Operations (1)

	2009		2008		2007	
(unaudited)	**$ millions**	**$/barrel**	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses	**4 277**		3 204		2 439	
Less: natural gas costs, inventory changes, stock-based compensation and other	**(400)**		(524)		(301)	
Less: Safe mode costs	**(380)**		—		—	
Less: non-monetary transactions	**(66)**		(111)		(102)	
Less: Syncrude-related operating, selling and general expenses	**(199)**		—		—	
Accretion of asset retirement obligations	**107**		55		40	
Cash costs	**3 339**	**31.50**	2 624	31.45	2 076	24.15
Natural gas	**252**	**2.40**	438	5.25	307	3.55
Imported bitumen (excluding other reported product purchases)	**8**	**0.05**	150	1.80	8	0.10
Cash operating costs	**3 599**	**33.95**	3 212	38.50	2 391	27.80
Project start-up costs	**51**	**0.45**	35	0.40	60	0.95
Total cash operating costs	**3 650**	**34.40**	3 247	38.90	2 451	28.75
Depreciation, depletion and amortization	**850**	**8.00**	580	6.95	462	5.40
Total operating costs	**4 500**	**42.40**	3 827	45.85	2 913	34.15
Production (thousands of barrels per day)	**290.6**		228.0		235.6	

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

Legal Notice – Forward-Looking Information

This Management's Discussion and Analysis contains certain forward-looking statements and other information that are based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of its experience and its perception of historical trends. These statements and information are subject to a number of risks and uncertainties, many of which are beyond the company's control.

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

Suncor's production targets are based on our current expectations, estimates, projections and assumptions. Uncertainties in the estimating process and the impact of future events may cause actual results to differ, in some cases materially, from our estimates. Assumptions are based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be relevant. For a description of assumptions and risk factors specifically related to these production targets, see page 51.

Certain financial measures referred to in MD&A, namely operating earnings, cash flow from operations, return on capital employed (ROCE) and oil sands cash and total operating costs per barrel, are not prescribed by GAAP. These non-GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. Suncor includes these non-GAAP financial measures because investors may use this information to analyze operating performance, leverage and liquidity. The additional information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. For a further description of these measures please refer to pages 52 and 53.

The risks, uncertainties and other factors that could influence actual results include but are not limited to, those risks, uncertainties and other factors described throughout this MD&A and: market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates; availability of third-party bitumen; success of hedging strategies; maintaining a desirable debt to cash flow ratio; changes in the general economic, market and business conditions; fluctuations in supply and demand for Suncor's products; commodity prices, interest rates and currency exchange rates; Suncor's ability to respond to changing markets and to receive timely regulatory approvals; the successful and timely implementation of capital projects including growth projects and regulatory projects; Suncor's inability to execute planned divestitures; political, economic and socio-economic risk associated with foreign operations (including OPEC production quotas); the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering needed to reduce the margin of error and increase the level of accuracy; the integrity and reliability of Suncor's capital assets; the cumulative impact of other resource development; the cost of compliance with current and future environmental laws; the accuracy of Suncor's reserve, resource and future production estimates and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venture partners; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; labour and material shortages; uncertainties resulting from potential delays or changes in plans with respect to projects or capital expenditures; actions by governmental authorities including the imposition of taxes or changes to fees and royalties; changes in environmental and other regulations (for example, the Government of Alberta's review of the unintended consequences of the proposed Crown royalty regime, and the Government of Canada's current review of greenhouse gas emission regulations); the ability and willingness of parties with whom we have material relationships to perform their obligations to us; the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor; failure to realize anticipated synergies or cost savings associated with our merger with Petro-Canada; risks regarding the integration of Petro-Canada and incorrect assessments of the value of Petro-Canada. The foregoing important factors are not exhaustive.

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

MANAGEMENT'S STATEMENT OF RESPONSIBILITY FOR FINANCIAL REPORTING

The management of Suncor Energy Inc. is responsible for the presentation and preparation of the accompanying consolidated financial statements of Suncor Energy Inc. on pages 59 to 100 and all related financial information contained in this Annual Report, including Management's Discussion and Analysis.

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles. They include certain amounts that are based on estimates and judgments relating to matters not concluded by year-end. Financial information presented elsewhere in this Annual Report is consistent with that contained in the consolidated financial statements.

In management's opinion, the consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies adopted by management as summarized on pages 59 to 63. If alternate accounting methods exist, management has chosen those policies it deems the most appropriate in the circumstances. In discharging its responsibilities for the integrity and reliability of the financial statements, management maintains and relies upon a system of internal controls designed to ensure that transactions are properly authorized and recorded, assets are safeguarded against unauthorized use or disposition and liabilities are recognized. These controls include quality standards in hiring and training of employees, formalized policies and procedures, a corporate code of conduct and associated compliance program designed to establish and monitor conflicts of interest, the integrity of accounting records and financial information among others, and employee and management accountability for performance within appropriate and well-defined areas of responsibility.

The system of internal controls is further supported by the professional staff of an internal audit function who conduct periodic audits of the company's financial reporting.

The company retains independent petroleum consultants, GLJ Petroleum Consultants Ltd., Sproule Associates Limited and RPS Energy Plc, to conduct independent evaluations of the company's oil and gas reserves and resources.

The Audit Committee of the Board of Directors, currently composed of six independent directors, reviews the effectiveness of the company's financial reporting systems, management information systems, internal control systems and internal auditors. It recommends to the Board of Directors the external auditors to be appointed by the shareholders at each annual meeting and reviews the independence and effectiveness of their work. In addition, it reviews with management and the external auditors any significant financial reporting issues, the presentation and impact of significant risks and uncertainties, and key estimates and judgments of management that may be material for financial reporting purposes. The Audit Committee appoints the independent petroleum consultants. The Audit Committee meets at least quarterly to review and approve interim financial statements prior to their release, as well as annually to review Suncor's annual financial statements and Management's Discussion and Analysis, Annual Information Form/Form 40-F, and annual reserves and resource estimates, and recommend their approval to the Board of Directors. The internal auditors and PricewaterhouseCoopers LLP have unrestricted access to the company, the Audit Committee and the Board of Directors.

Richard L. George
President and
Chief Executive Officer

Bart Demosky
Chief Financial Officer

February 26, 2010

The following report is provided by management in respect of the Company's internal control over financial reporting (as defined in Rule13a-15(f) under the U.S. Securities Exchange Act of 1934):

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

1. Management is responsible for establishing and maintaining adequate internal control over the Company's financial reporting.
2. On August 1, 2009, Suncor completed its merger with Petro-Canada. As permitted by the Securities and Exchange Commission, management has excluded Petro-Canada from its evaluation of the effectiveness of Suncor's internal control over financial reporting as of December 31, 2009. Assets attributable to Petro-Canada as of August 1, 2009 represented approximately 50% of Suncor's total assets as of August 1, 2009, and revenues attributable to Petro-Canada for the period August 1, 2009 to December 31, 2009 represented approximately 25% of Suncor's total revenues for the year ended December 31, 2009.
3. Management has used the Committee of Sponsoring Organizations of the Treadway Commission (COSO) framework in Internal Control — Integrated Framework to evaluate the effectiveness of the Company's internal control over financial reporting.
4. Management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2009, and has concluded that such internal control over financial reporting was effective as of that date. Additionally, based on this assessment, management determined that there were no material weaknesses in internal control over financial reporting as of December 31, 2009. Because of inherent limitations, systems of internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.
5. The effectiveness of the Company's internal control over financial reporting as of December 31, 2009 has been audited by PricewaterhouseCoopers LLP, independent auditors, as stated in their report which appears herein.

Richard L. George
President and
Chief Executive Officer

Bart Demosky
Chief Financial Officer

February 26, 2010

INDEPENDENT AUDITORS' REPORT

TO THE SHAREHOLDERS OF SUNCOR ENERGY INC.

We have completed integrated audits of Suncor Energy Inc's 2009, 2008 and 2007 consolidated financial statements and of its internal control over financial reporting as at December 31, 2009. Our opinions, based on our audits, are presented below.

Consolidated financial statements

We have audited the accompanying consolidated balance sheets of Suncor Energy Inc. ("the company") as at December 31, 2009 and December 31, 2008, and the related consolidated statements of earnings, comprehensive income, changes in shareholders' equity and of cash flows for each of the years in the three year period ended December 31, 2009. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits of the company's financial statements as at December 31, 2009 and 2008 and for each of the years in the three year period ended December 31, 2009 in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the company as at December 31, 2009 and December 31, 2008 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2009 in accordance with Canadian generally accepted accounting principles.

Internal control over financial reporting

We have also audited the company's internal control over financial reporting as at December 31, 2009, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management's Report on Internal Control over Financial Reporting, management has excluded Petro-Canada from its assessment of internal control over financial reporting as at December 31, 2009 because it was acquired by the company in a purchase business combination during 2009. We have also excluded Petro-Canada from our audit of internal control over financial reporting. Assets attributable to Petro-Canada as of August 1, 2009 represented approximately 50% of the company's total assets as of August 1, 2009, and revenues attributable to Petro-Canada for the period August 1, 2009 to December 31, 2009 represented approximately 25% of the company's total revenues for the year ended December 31, 2009.

In our opinion, the company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2009 based on criteria established in Internal Control – Integrated Framework issued by the COSO.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

February 26, 2010

SUNCOR ENERGY INC.
SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Principles of Consolidation and the Preparation of Financial Statements

These consolidated financial statements are prepared and reported in Canadian dollars in accordance with generally accepted accounting principles (GAAP) in Canada, which differ in some respects from GAAP in the United States. These differences are quantified and explained in note 23.

The consolidated financial statements include the accounts of Suncor Energy Inc. and its subsidiaries and the company's proportionate share of the assets, liabilities, equity, revenues, expenses and cash flows of its joint ventures (the "company"). Subsidiaries are defined as entities in which the company holds a controlling interest, is the general partner or where it is subject to the majority of expected losses or gains.

The timely preparation of financial statements requires that management make estimates and assumptions, and use judgment regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Significant estimates used in the preparation of the financial statements include, but are not limited to, asset retirement obligations, income taxes, employee future benefits, valuation of derivative instruments, the estimates of oil and natural gas reserves and related depreciation, depletion and amortization, and the valuation of goodwill.

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

(b) Revenues

Revenue from the sale of crude oil, natural gas, natural gas liquids, purchased products and refined petroleum products is recorded when title passes to the customer and collection is reasonably assured. Revenue from oil and natural gas production is recorded net of royalties payable to governments and other mineral interest owners and revenue from properties in which the company has an interest with other producers is recognized on the basis of the company's net working interest. Inter-segment sales of crude oil and natural gas are accounted for at market values and included, for segmented reporting, in revenues of the segment making the transfer and expenses of the segment receiving the transfer. Inter-segment amounts are eliminated on consolidation.

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

(c) Transportation Costs

Transportation costs billed to customers are classified as revenues with the related transportation costs classified as transportation in the Consolidated Statements of Earnings.

(d) Foreign Currency Translation

The International operating segment, the United States operations of our refining and marketing and natural gas businesses, and our corporate self-insurance operations are classified as self-sustaining and are translated into Canadian dollars using the current rate method. Assets and liabilities are translated at the period-end exchange rate, while revenues and expenses are translated using average exchange rates during the period. Translation gains or losses are included in other comprehensive income (loss) in the Consolidated Statements of Comprehensive Income.

Otherwise, monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at rates of exchange in effect at the end of the period. The resulting exchange gains and losses are included in earnings. With the exception of balances pertaining to self-sustaining operations, other assets and related depreciation, depletion and amortization, other liabilities, revenues and expenses are translated at rates of exchange in effect at the respective transaction dates. The resulting exchange gains and losses are included in earnings.

(e) Income Taxes

Suncor follows the liability method of accounting for income taxes. Future income taxes are recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using enacted or substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs. Investment tax credits are recorded as an offset to the related expenditures.

(f) Earnings Per Share

Basic earnings per share are calculated by dividing the net earnings by the weighted-average number of common shares outstanding. Diluted earnings per share reflect the potential dilution that would occur if stock options, excluding stock options with a cash payment alternative were exercised. The treasury stock method is used in calculating diluted earnings per share, which assumes that any proceeds received from the exercise of in-the-money stock options would be used to purchase common shares at the average market price for the period. A liability and expense is recorded for stock options with a cash payment alternative. Accordingly, the potential issuance of common shares associated with these stock options is not included in the calculation of diluted earnings per share.

(g) Cash and Cash Equivalents

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

(h) Inventories

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

Inventories held for trading purposes in the company's energy supply and trading operations are carried at fair value less costs to sell and any changes in fair value are recognized as gains or losses within Energy Supply and Trading Activities revenue in the Consolidated Statements of Earnings.

(i) Investments

Investments in companies over which the company has significant influence are accounted for using the equity method.

(j) Property, Plant and Equipment

Cost

Property, plant and equipment are recorded at cost.

The company follows the successful efforts method of accounting for the exploration and development expenditures of oil and gas producing activities. Under the successful efforts method, acquisition costs of proved and unproved properties are capitalized. Costs of unproved properties are transferred to proved properties when proved reserves are confirmed. Exploration costs, including geological and geophysical costs, are expensed as incurred. Exploratory drilling costs are initially capitalized. If it is determined that a specific well does not contain proved reserves, the related capitalized exploratory drilling costs are charged to expense, as dry hole costs, at that time.

Development costs, including the costs of developing production facilities, which include the costs of wellhead equipment, development drilling costs, applicable geological and geophysical costs, gas plants and handling facilities, offshore platforms and subsea structures, upgraders, extraction plants and the costs of acquiring or constructing support facilities and equipment are capitalized. Costs incurred to operate and maintain wells and equipment and to lift oil and gas to the surface are expensed as operating costs.

Development of oil sands mining activities are capitalized when costs are recoverable and directly result in an identifiable future benefit.

Costs incurred after the inception of operations are expensed. Planned major maintenance and expenditures that increase capacity or extend the useful lives of assets are capitalized.

Interest Capitalization

Interest costs relating to major capital projects in progress are capitalized as part of property, plant and equipment. Capitalization of interest ceases when the capital asset is substantially complete and ready for its intended productive use. Capitalization of

interest is suspended while an asset is in safe mode. Capitalized interest cannot exceed the actual interest incurred during the period.

Leases

Leases that transfer substantially all the benefits and risks of ownership to the company are recorded as capital leases and classified as property, plant and equipment with offsetting long-term debt. All other leases are classified as operating leases under which leasing costs are expensed in the period incurred.

Depreciation, Depletion and Amortization

Depreciation and depletion of property, plant and equipment for oil and gas producing properties follow successful efforts accounting. Acquisition costs of unproved properties for natural gas and conventional crude are amortized over the lease term until proved reserves are confirmed. Exploration drilling and development costs are depleted over the remaining proved developed reserves. Proved property acquisition costs are depleted over the remaining proved reserves.

Mine and mobile equipment costs are depleted on unit-of-production basis over proved developed reserves or depreciated on a straight-line basis over periods ranging from two to 20 years, while mining extraction and upgrading facilities and other property and equipment, including leases in service, are depreciated on a straight-line basis over periods ranging from four to 40 years. Gas plants, central processing facilities of in-situ oil sands activities, and support facilities and equipment are depreciated on a straight-line basis over their useful lives, which range from 3 years to 30 years.

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

Depreciation of property, plant and equipment in the refining and marketing operations are provided on a straight-line basis over the useful lives of assets. The refineries and lubricants plant and additions thereto are depreciated over an average of 30 years, service stations and related equipment over four to 20 years and pipeline facilities and other equipment over three to 40 years.

Depreciation, depletion and amortization rates for all capitalized costs associated with all of the company's activities are reviewed, at least annually, or when events or conditions occur that impact capitalized costs, reserves or estimated service lives.

The cost of major maintenance shutdowns is capitalized and amortized on a straight-line basis over the period to the next shutdown, which varies from three to nine years.

Impairment

Property, plant and equipment are reviewed for impairment whenever events or conditions indicate that their net carrying amount may not be recoverable from estimated undiscounted future cash flows. If it is determined that the estimated net recoverable amount is less than the net carrying amount, a write-down to the asset's fair value is recognized during the period, with a charge to earnings.

Disposals and Abandonments

Gains or losses on disposals of non-oil and gas property, plant and equipment are recognized in earnings. For oil and gas property, plant and equipment, gains or losses on significant disposals or disposal of an entire property are recognized in earnings. All other disposals and abandonments of oil and gas property, plant and equipment are charged to depreciation, depletion and amortization expense.

(k) Business Combinations and Goodwill

Acquisitions are accounted for using the purchase method in accordance with Canadian Institute of Chartered Accountants ("CICA") Handbook section 1581. Under this method, the purchase consideration of the combination is allocated to the identifiable assets, liabilities and contingent liabilities on the basis of fair value as of the date of acquisition.

Goodwill, which is not amortized, is the excess of the purchase price over such fair value and is assigned to the appropriate reporting units. The carrying value of goodwill is assessed for impairment annually or more frequently as economic events dictate, by comparing the fair value of the reporting unit to its carrying value, including goodwill. If the fair value of the reporting unit is less than its carrying value, goodwill impairment is recognized as the excess of the carrying value of the goodwill over the fair value of the goodwill.

(l) Intangible Assets

Intangible assets, other than goodwill, include acquired customers lists and brand value and are stated at the amount initially recognized, less accumulated amortization. Intangible assets with a finite life are amortized over their expected useful lives which range from five to 10 years, while intangible assets with an indefinite useful life are not subject to amortization. Expected useful

lives of intangible assets are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

The carrying values of intangible assets with a finite life are reviewed for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. Intangible assets with an indefinite useful life are assessed for impairment annually, or more frequently as economic events dictate that carrying value may be less than fair value. If it is determined that the estimated net recoverable amount or fair value is less than the net carrying amount, a write-down is recognized during the period, with a charge to earnings.

(m) Asset Retirement Obligations

A liability is recognized for future retirement obligations associated with the company's property, plant and equipment. The fair value of the Asset Retirement Obligation (ARO) is recorded on a discounted basis. This amount is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the company settles the obligation. Changes in the estimated obligation resulting from revisions to the estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and related asset. Actual expenditures incurred are charged against the accumulated obligation.

(n) Stock-Based Compensation Plans

Under the company's common stock-based compensation plans (see note 15), stock-based awards are granted to executives, employees and non-employee directors. Compensation expense is recorded in the Consolidated Statements of Earnings as operating, selling and general expense.

For common share options granted to employees and non-employee directors on or after January 1, 2003, the expense is based on the fair values of the option at the time of grant and is recognized in the Consolidated Statements of Earnings over the estimated vesting periods of the respective options. A corresponding increase is recorded as contributed surplus in the Consolidated Statements of Changes in Shareholders' Equity. Consideration paid to the company on exercise of options is credited to share capital.

Stock-based compensation awards that are to be settled in cash or have the option to settle in cash or shares are measured using the intrinsic value method at each period end. A liability and expense are recorded over the vesting period in the amount by which the then current market price exceeds the option exercise price. The expense is recognized in the Consolidated Statements of Earnings. When awards are surrendered for cash, the cash settlement paid reduces the outstanding liability. When awards are exercised for common shares, consideration paid by the holder and the previously recognized liability associated with the stock options are recorded as common shares.

For employees eligible to retire prior to the vesting date, the compensation expense is recognized over the shorter period. In instances where an employee is eligible to retire at the time of grant, the full expense is recognized immediately.

(o) Employee Future Benefits

The company's employee future benefit programs consist of defined benefit and defined contribution pension plans, as well as other post-retirement benefits as described in note 14.

The estimated future cost of providing defined benefit pension and other post-retirement benefits is actuarially determined using management's best estimates of demographic and financial assumptions, and such cost is accrued proportionately from the date of hire of the employee to the date the employee becomes fully eligible to receive the benefits. The discount rate used to determine accrued benefit obligations is based on a year-end market rate of interest for high-quality corporate debt instruments with cash flows that match the timing and amount of expected benefit payments.

Company contributions to the defined contribution plan are expensed as incurred.

(p) Financial Instruments

All financial instruments are initially recognized at fair value on the balance sheet. The company has classified each financial instrument into one of the following categories: held-for-trading financial assets and liabilities, loans and receivables, held-to-maturity financial assets, and other financial liabilities. Subsequent measurement of financial instruments is based on their classification.

Held-for-trading financial assets and liabilities are subsequently measured at fair value with changes in those fair values recognized in net earnings. Loans and receivables, held-to-maturity financial assets and other financial liabilities are subsequently measured at amortized cost using the effective interest method.

The company classifies cash and cash equivalents as held-for-trading financial assets, accounts receivable as loans and receivables, and accounts payable and accrued liabilities, short-term notes payable, long-term debt and other liabilities as other financial liabilities. The company combines transaction costs and premiums or discounts directly attributable to the issuance of long-term debt with the fair value of the debt and amortizes these amounts to earnings using the effective interest method, with the exception of the portion of debt that has related financial hedges, which is accounted for under the fair value hedge methodology outlined below.

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.

Derivative Financial Instruments

The company may use derivative financial instruments to manage certain exposures to fluctuations in interest rates, commodity prices, foreign exchange rates, as well as for trading purposes. Derivative contracts for trading and non-trading activities are required to be recorded on the balance sheet at fair value. Derivative contracts that the company accounts for as designated hedges are assessed at each reporting date to determine if the relationship between the derivative and the underlying hedged exposure is still effective, and to quantify any ineffectiveness in the relationship.

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

Gains or losses arising from hedging activities, including the ineffective portion, are reported in the same caption as the hedged item. The determination of hedge effectiveness and the measurement of hedge ineffectiveness for cash flow hedges are based on internally derived valuations that utilize observable market data. The company uses these valuations to estimate the fair values of the underlying physical commodity contracts.

Derivative contracts not accounted for as designated hedges are recorded on the balance sheet at fair value, with any change in fair value immediately recorded as a net gain or loss in net earnings.

(q) Recent Accounting Pronouncements

Business Combinations

In January 2009, the CICA issued section 1582 "Business Combinations" to replace section 1581. The CICA concurrently issued section 1601 "Consolidated Financial Statements" and section 1602 "Non-Controlling Interests" which replace section 1600 "Consolidated Financial Statements". Prospective application of the standards is effective for fiscal years beginning on or after January 1, 2011, with early adoption permitted. The new standards revise guidance on the determination of the carrying amount of the assets acquired and liabilities assumed, goodwill and accounting for non-controlling interests at the time of a business combination. The company applied section 1581 to the Petro-Canada business combination; however the company will continue to consider the application of section 1582 to business combinations in 2010.

CONSOLIDATED STATEMENTS OF EARNINGS

For the years ended December 31 ($ millions)	2009	2008 (restated)	2007 (restated)
Revenues			
Operating revenues (notes 4 and 22)	**18 658**	18 179	15 193
Less: Royalties	**(1 199)**	(890)	(691)
Operating revenues (net of royalties)	**17 459**	17 289	14 502
Energy supply and trading activities (notes 4 and 5)	**7 577**	11 320	2 782
Interest and other income (note 2e)	**444**	28	30
	25 480	28 637	17 314
Expenses			
Purchases of crude oil and products	**7 383**	7 582	6 414
Operating, selling and general (note 15)	**6 641**	4 186	3 450
Energy supply and trading activities (notes 4 and 5)	**7 381**	11 323	2 870
Transportation	**427**	246	160
Depreciation, depletion and amortization	**2 306**	1 049	864
Accretion of asset retirement obligations	**155**	64	48
Exploration (note 21)	**268**	90	95
Loss on disposal of assets	**66**	13	7
Project start-up costs	**51**	35	68
Financing expenses (income) (note 6)	**(487)**	917	(211)
	24 191	25 505	13 765
Earnings Before Income Taxes	**1 289**	3 132	3 549
Provisions for (Recovery of) Income Taxes (note 7)			
Current	**868**	514	382
Future	**(725)**	481	184
	143	995	566
Net Earnings	**1 146**	2 137	2 983
Net Earnings Per Common Share (dollars) (note 8)			
Basic	**0.96**	2.29	3.23
Diluted	**0.95**	2.26	3.17
Cash dividends	**0.30**	0.20	0.19

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years ended December 31 ($ millions)	2009	2008	2007
Net earnings	**1 146**	2 137	2 983
Other comprehensive income (loss), net of tax (notes 4 and 20)			
Change in foreign currency translation adjustment	**(332)**	350	(195)
Gain on derivative contracts designated as cash flow hedges	**2**	—	5
Comprehensive Income	**816**	2 487	2 793

See accompanying Summary of Significant Accounting Policies and Notes.

CONSOLIDATED BALANCE SHEETS

As at December 31 ($ millions)	**2009 (note 2)**	2008 (restated) (note 1)
Assets		
Current assets		
Cash and cash equivalents	**505**	660
Accounts receivable (note 4)	**3 936**	1 580
Inventories (note 11)	**2 971**	909
Income taxes receivable	**587**	67
Future income taxes (note 7)	**332**	21
Total current assets	**8 331**	3 237
Property, plant and equipment, net (note 13)	**57 485**	28 882
Other assets (note 12)	**536**	388
Goodwill (note 2d)	**3 201**	21
Future income taxes (note 7)	**193**	—
Total assets	**69 746**	32 528
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**2**	2
Current portion of long-term debt	**25**	18
Accounts payable and accrued liabilities (notes 4, 14, 15 and 16)	**6 529**	3 326
Income taxes payable	**1 274**	81
Future income taxes (note 7)	**18**	111
Total current liabilities	**7 848**	3 538
Long-term debt (note 17)	**13 855**	7 866
Accrued liabilities and other (notes 4, 14, 15 and 16)	**5 062**	1 986
Future income taxes (note 7)	**8 870**	4 615
Shareholders' equity (see below)	**34 111**	14 523
Total liabilities and shareholders' equity	**69 746**	32 528

Commitments and contingencies (note 19)

SHAREHOLDERS' EQUITY

As at December 31 ($ millions)	**Number (thousands)**	**2009**	Number (thousands)	2008
Share capital	**1 559 778**	**20 053**	935 524	1 113
Contributed surplus		**526**		288
Accumulated other comprehensive income (loss) (notes 4 and 20)		**(233)**		97
Retained earnings		**13 765**		13 025
Total shareholders' equity		**34 111**		14 523

See accompanying Summary of Significant Accounting Policies and Notes.

Approved on behalf of the Board of Directors:

Richard L. George,
Director

Brian A. Canfield,
Director

February 26, 2010

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31 ($ millions)	2009	2008 (restated)	2007 (restated)
Operating Activities			
Net earnings	**1 146**	2 137	2 983
Adjustments for:			
Depreciation, depletion and amortization	**2 306**	1 049	864
Future income taxes	**(725)**	481	184
Accretion of asset retirement obligations	**155**	64	48
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(858)**	919	(252)
Change in fair value of derivative contracts	**980**	(638)	6
Loss on disposal of assets	**66**	13	7
Stock-based compensation	**262**	(22)	148
Gain on effective settlement of pre-existing contract with Petro-Canada (note 2e)	**(438)**	—	—
Other	**(278)**	(7)	(18)
Exploration expenses	**183**	61	67
Cash flow from operating activities before changes in non-cash working capital	**2 799**	4 057	4 037
Decrease (increase) in non-cash working capital related to operating activities (note 10)	**(224)**	405	(144)
Cash flow from operating activities	**2 575**	4 462	3 893
Investing Activities			
Capital and exploration expenditures	**(4 246)**	(7 987)	(5 629)
Deferred outlays and other investments	**(30)**	(51)	(32)
Cash acquired through business combination (net) (note 2d)	**248**	—	—
Proceeds from disposals	**148**	33	9
Decrease (increase) in non-cash working capital related to investing activities	**(791)**	415	290
Cash flow used in investing activities	**(4 671)**	(7 590)	(5 362)
Net cash deficiency before financing activities	**(2 096)**	(3 128)	(1 469)
Financing Activities			
Decrease in short-term debt	**—**	(1)	(4)
Net proceeds from issuance of long-term debt	**—**	2 704	1 835
Net increase (decrease) in revolving-term debt	**2 325**	422	(171)
Issuance of common shares under stock option plan	**41**	190	62
Dividends paid on common shares	**(401)**	(180)	(162)
Deferred revenue	**—**	—	4
Cash flow provided by financing activities	**1 965**	3 135	1 564
Increase (Decrease) in Cash and Cash Equivalents	**(131)**	7	95
Effect of Foreign Exchange on Cash and Cash Equivalents	**(24)**	84	(47)
Cash and Cash Equivalents at Beginning of Period	**660**	569	521
Cash and Cash Equivalents at End of Period	**505**	660	569

See accompanying Summary of Significant Accounting Policies and Notes.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

For the years ended December 31 ($ millions)	Share Capital	Contributed Surplus	Accumulated Other Comprehensive Income (AOCI)	Retained Earnings
At December 31, 2006	794	100	(71)	8 261
Net earnings	—	—	—	2 983
Dividends paid on common shares	—	—	—	(162)
Issued for cash under stock option plans	74	(12)	—	—
Issued under dividend reinvestment plan	13	—	—	(13)
Stock-based compensation expense	—	103	—	—
Income tax benefit of stock option deductions in the U.S.	—	3	—	—
Adjustment to opening retained earnings arising from ineffective portion of cash flow hedges at January 1, 2007	—	—	—	5
Adjustment to opening AOCI arising from effective portion of cash flow hedges at January 1, 2007	—	—	8	—
Change in accumulated other comprehensive income (loss)	—	—	(190)	—
At December 31, 2007	881	194	(253)	11 074
Net earnings	—	—	—	2 137
Dividends paid on common shares	—	—	—	(180)
Issued for cash under stock option plans	226	(36)	—	—
Issued under dividend reinvestment plan	6	—	—	(6)
Stock-based compensation expense	—	120	—	—
Income tax benefit of stock option deductions in the U.S.	—	10	—	—
Change in accumulated other comprehensive income (loss)	—	—	350	—
At December 31, 2008	**1 113**	**288**	**97**	**13 025**
Net earnings	**—**	**—**	**—**	**1 146**
Dividends paid on common shares	**—**	**—**	**—**	**(401)**
Issued for cash under stock option plans	**57**	**(16)**	**—**	**—**
Issued under dividend reinvestment plan	**5**	**—**	**—**	**(5)**
Stock-based compensation expense	**—**	**103**	**—**	**—**
Issued for Petro-Canada acquisition (note 2c)	**18 878**	**—**	**—**	**—**
Fair value of Petro-Canada stock options exchanged for Suncor stock options (note 2c)	**—**	**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**

See accompanying Summary of Significant Accounting Policies and Notes.

SCHEDULES OF SEGMENTED DATA[a]

For the Years Ended December 31 ($ millions)	Oil Sands 2009	Oil Sands 2008	Oil Sands 2007	Natural Gas 2009	Natural Gas 2008	Natural Gas 2007	East Coast Canada 2009	East Coast Canada 2008	East Coast Canada 2007	International 2009	International 2008	International 2007
EARNINGS												
Revenues[b]												
Operating revenues	**4 135**	8 045	6 160	**612**	696	541	**499**	—	—	**1 434**	—	—
Less: Royalties	**(645)**	(715)	(565)	**(85)**	(175)	(126)	**(217)**	—	—	**(252)**	—	—
Operating revenues (net of royalties)	**3 490**	7 330	5 595	**527**	521	415	**282**	—	—	**1 182**	—	—
Energy supply and trading activities	**—**	—	—	**—**	—	—	**—**	—	—	**—**	—	—
Intersegment revenues[c]	**2 609**	1 309	580	**154**	58	12	**159**	—	—	**—**	—	—
Interest and other income	**440**	—	—	**—**	—	—	**—**	—	—	**1**	—	—
	6 539	8 639	6 175	**681**	579	427	**441**	—	—	**1 183**	—	—
Expenses												
Purchases of crude oil and products	**325**	574	157	**—**	—	—	**33**	—	—	**—**	—	—
Operating, selling and general	**4 277**	3 203	2 439	**322**	160	155	**72**	—	—	**242**	—	—
Energy supply and trading activities	**—**	—	—	**—**	—	—	**—**	—	—	**—**	—	—
Transportation	**248**	229	138	**58**	17	15	**19**	—	—	**33**	—	—
Depreciation, depletion and amortization	**922**	580	462	**448**	225	189	**184**	—	—	**400**	—	—
Accretion of asset retirement obligations	**111**	55	40	**22**	8	7	**4**	—	—	**17**	—	—
Exploration	**10**	17	13	**127**	73	82	**4**	—	—	**127**	—	—
Loss (gain) on disposal of assets	**70**	36	1	**(20)**	(22)	(1)	**—**	—	—	**—**	—	—
Project start-up costs	**51**	35	60	**—**	—	—	**—**	—	—	**—**	—	—
Financing expenses (income)	**1**	—	—	**—**	—	—	**1**	—	—	**(1)**	—	—
	6 015	4 729	3 310	**957**	461	447	**317**	—	—	**818**	—	—
Earnings (loss) before income taxes	**524**	3 910	2 865	**(276)**	118	(20)	**124**	—	—	**365**	—	—
Income taxes	**33**	(1 035)	(391)	**77**	(29)	45	**(12)**	—	—	**(200)**	—	—
Net earnings (loss)	**557**	2 875	2 474	**(199)**	89	25	**112**	—	—	**165**	—	—
As at December 31												
TOTAL ASSETS	**37 553**	25 795	18 172	**5 003**	1 862	1 811	**4 771**	—	—	**9 913**	—	—

(a) Accounting policies for segments are the same as those described in the Summary of Significant Accounting Policies.
(b) There were no customers that represented 10% or more of the company's 2009, 2008 or 2007 consolidated revenues.
(c) Intersegment revenues are recorded at prevailing fair market prices and accounted for as if the sales were to third parties.

See accompanying Summary of Significant Accounting Policies and Notes.

For the Years Ended December 31 ($ millions)	Refining and Marketing 2009	2008	2007	Corporate, Energy Trading and Eliminations 2009	2008	2007	Total 2009	2008	2007
EARNINGS									
Revenues[b]									
Operating revenues	**11 962**	9 418	8 486	**16**	20	6	**18 658**	18 179	15 193
Less: Royalties	**—**	—	—	**—**	—	—	**(1 199)**	(890)	(691)
Operating revenues (net of royalties)	**11 962**	9 418	8 486	**16**	20	6	**17 459**	17 289	14 502
Energy supply and trading activities	**—**	—	—	**7 577**	11 320	2 782	**7 577**	11 320	2 782
Intersegment revenues[c]	**51**	—	(100)	**(2 973)**	(1 367)	(492)	**—**	—	—
Interest and other income	**—**	1	5	**3**	27	25	**444**	28	30
	12 013	9 419	8 391	**4 623**	10 000	2 321	**25 480**	28 637	17 314
Expenses									
Purchases of crude oil and products	**9 731**	8 472	6 847	**(2 706)**	(1 464)	(590)	**7 383**	7 582	6 414
Operating, selling and general	**1 279**	746	720	**449**	77	136	**6 641**	4 186	3 450
Energy supply and trading activities	**—**	—	—	**7 381**	11 323	2 870	**7 381**	11 323	2 870
Transportation	**87**	16	20	**(18)**	(16)	(13)	**427**	246	160
Depreciation, depletion and amortization	**323**	202	171	**29**	42	42	**2 306**	1 049	864
Accretion of asset retirement obligations	**1**	1	1	**—**	—	—	**155**	64	48
Exploration	**—**	—	—	**—**	—	—	**268**	90	95
Loss (gain) on disposal of assets	**16**	6	7	**—**	(7)	—	**66**	13	7
Project start-up costs	**—**	—	8	**—**	—	—	**51**	35	68
Financing expenses (income)	**4**	—	—	**(492)**	917	(211)	**(487)**	917	(211)
	11 441	9 443	7 774	**4 643**	10 872	2 234	**24 191**	25 505	13 765
Earnings (loss) before income taxes	**572**	(24)	617	**(20)**	(872)	87	**1 289**	3 132	3 549
Income taxes	**(139)**	19	(175)	**98**	50	(45)	**(143)**	(995)	(566)
Net earnings (loss)	**433**	(5)	442	**78**	(822)	42	**1 146**	2 137	2 983
As at December 31									
TOTAL ASSETS	**10 568**	3 795	4 065	**1 938**	1 076	461	**69 746**	32 528	24 509

SCHEDULES OF SEGMENTED DATA[a] (continued)

For the Years Ended December 31 ($ millions)	Oil Sands 2009	Oil Sands 2008	Oil Sands 2007	Natural Gas 2009	Natural Gas 2008	Natural Gas 2007	East Coast Canada 2009	East Coast Canada 2008	East Coast Canada 2007	International 2009	International 2008	International 2007
CASH FLOW BEFORE FINANCING ACTIVITIES												
Operating activities												
Net earnings (loss)	**557**	2 875	2 474	**(199)**	89	25	**112**	—	—	**165**	—	—
Adjustments for:												
Depreciation, depletion and amortization	**922**	580	462	**448**	225	189	**184**	—	—	**400**	—	—
Future income taxes	**(643)**	535	108	**(52)**	15	(43)	**12**	—	—	**(56)**	—	—
Accretion of asset retirement obligations	**111**	55	40	**22**	8	7	**4**	—	—	**17**	—	—
Unrealized (gain) loss on translation of U.S. dollar denominated long-term debt	**—**	—	—	**—**	—	—	**—**	—	—	**—**	—	—
Change in fair value of derivative contracts	**960**	(590)	10	**—**	—	2	**—**	—	—	**—**	—	—
Loss (gain) on disposal of assets	**70**	36	1	**(20)**	(22)	(1)	**—**	—	—	**—**	—	—
Stock-based compensation	**90**	54	86	**19**	4	7	**2**	—	—	**10**	—	—
Gain on effective settlement of pre-existing contract with Petro-Canada	**(438)**	—	—	**—**	—	—	**—**	—	—	**—**	—	—
Other	**(378)**	(38)	(16)	**(11)**	(13)	(2)	**21**	—	—	**19**	—	—
Exploration expenses	**—**	—	—	**122**	61	67	**—**	—	—	**61**	—	—
Cash flow from (used in) operating activities before changes in non-cash working capital	**1 251**	3 507	3 165	**329**	367	251	**335**	—	—	**616**	—	—
Decrease (increase) in operating working capital	**(202)**	934	564	**(9)**	43	19	**(34)**	—	—	**(35)**	—	—
Total cash from (used in) operating activities	**1 049**	4 441	3 729	**320**	410	270	**301**	—	—	**581**	—	—
Investing activities:												
Capital and exploration expenditures	**(2 807)**	(7 391)	(4 566)	**(320)**	(342)	(537)	**(123)**	—	—	**(543)**	—	—
Deferred outlays and other investments	**(36)**	(39)	(18)	**—**	—	—	**—**	—	—	**—**	—	—
Cash acquired through business combination (net)	**—**	—	—	**—**	—	—	**—**	—	—	**—**	—	—
Proceeds from disposals	**96**	—	3	**27**	26	5	**—**	—	—	**—**	—	—
Decrease (increase) in investing working capital	**(799)**	434	333	**(19)**	—	—	**(29)**	—	—	**60**	—	—
Total cash from (used in) investing activities	**(3 546)**	(6 996)	(4 248)	**(312)**	(316)	(532)	**(152)**	—	—	**(483)**	—	—
Net cash surplus (deficiency) before financing activities	**(2 497)**	(2 555)	(519)	**8**	94	(262)	**149**	—	—	**98**	—	—

(a) Accounting policies for segments are the same as those described in the Summary of Significant Accounting Policies.

See accompanying Summary of Significant Accounting Policies and Notes.

For the Years Ended December 31 ($ millions)	Refining and Marketing 2009	2008	2007	Corporate, Energy Trading and Eliminations 2009	2008	2007	Total 2009	2008	2007
CASH FLOW BEFORE FINANCING ACTIVITIES									
Operating activities									
Net earnings (loss)	**433**	(5)	442	**78**	(822)	42	**1 146**	2 137	2 983
Adjustments for:									
Depreciation, depletion and amortization	**323**	202	171	**29**	42	42	**2 306**	1 049	864
Future income taxes	**109**	(7)	77	**(95)**	(62)	42	**(725)**	481	184
Accretion of asset retirement obligations	**1**	1	1	**—**	—	—	**155**	64	48
Unrealized (gain) loss on translation of U.S. dollar denominated long-term debt	**—**	—	—	**(858)**	919	(252)	**(858)**	919	(252)
Change in fair value of derivative contracts	**(14)**	27	(6)	**34**	(75)	—	**980**	(638)	6
Loss (gain) on disposal of assets	**16**	6	7	**—**	(7)	—	**66**	13	7
Stock-based compensation	**35**	16	35	**106**	(96)	20	**262**	(22)	148
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	—	—	**—**	—	—	**(438)**	—	—
Other	**60**	8	(16)	**11**	36	16	**(278)**	(7)	(18)
Exploration expenses	**—**	—	—	**—**	—	—	**183**	61	67
Cash flow from (used in) operating activities before changes in non-cash working capital	**963**	248	711	**(695)**	(65)	(90)	**2 799**	4 057	4 037
Decrease (increase) in operating working capital	**(270)**	292	(247)	**326**	(864)	(480)	**(224)**	405	(144)
Total cash from (used in) operating activities	**693**	540	464	**(369)**	(929)	(570)	**2 575**	4 462	3 893
Investing activities:									
Capital and exploration expenditures	**(409)**	(226)	(449)	**(44)**	(28)	(77)	**(4 246)**	(7 987)	(5 629)
Deferred outlays and other investments	**(3)**	(11)	—	**9**	(1)	(14)	**(30)**	(51)	(32)
Cash acquired through business combination (net)	**—**	—	—	**248**	—	—	**248**	—	—
Proceeds from disposals	**25**	—	1	**—**	7	—	**148**	33	9
Decrease (increase) in investing working capital	**(4)**	(19)	(43)	**—**	—	—	**(791)**	415	290
Total cash from (used in) investing activities	**(391)**	(256)	(491)	**213**	(22)	(91)	**(4 671)**	(7 590)	(5 362)
Net cash surplus (deficiency) before financing activities	**302**	284	(27)	**(156)**	(951)	(661)	**(2 096)**	(3 128)	(1 469)

SUNCOR ENERGY INC.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. CHANGES IN ACCOUNTING POLICIES AND DISCLOSURES

(a) Goodwill and Intangible Assets

On January 1, 2009, the company retroactively adopted Canadian Institute of Chartered Accountants (CICA) Handbook section 3064 "Goodwill and Intangible Assets." This new standard replaces section 3062 "Goodwill and Other Intangible Assets" and section 3450 "Research and Development Costs," and focuses on the criteria for asset recognition in the financial statements, including those internally developed. The impact of adopting this standard resulted in a change in the classification of our deferred maintenance shutdown costs that had previously been classified within other assets and amortized over the period to the next shutdown. At December 31, 2008, property, plant and equipment was increased by $566 million, with an equal and offsetting reduction to other assets.

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

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

(c) Financial Instruments Disclosures

On December 31, 2009, the company prospectively adopted amendments to CICA Handbook section 3862 "Financial Instruments: Disclosures," requiring adoption for annual periods ending on or after September 30, 2009. The amendments require additional disclosures on fair value measurements of financial instruments and enhanced liquidity risk disclosure. These additional disclosures are provided in note 4.

2. BUSINESS COMBINATION WITH PETRO-CANADA

(a) Overview

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

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

(b) Accounting for Business Combinations

The company has accounted for this business combination as prescribed by CICA Handbook section 1581 "Business Combinations." As 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.

(c) Consideration and Purchase Price

Consideration offered to complete the merger included 621.1 million shares of Suncor with a value of $18,878 million, or $30.39 per share, that were issued to Petro-Canada shareholders and 7.1 million Suncor share options with a fair value of $147 million, that were exchanged for existing Petro-Canada share options. The replacement of stock options and other stock-based compensation plans that are accounted for as liabilities are not included in consideration (see note 15).

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

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

(d) Preliminary Allocation of Purchase Price

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

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

The preliminary purchase price allocation is based on current best estimates by Suncor's management and is based principally on valuations prepared by independent valuation specialists.

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

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

The fair value for current liabilities includes $216 million for provisions for costs related to exiting certain activities of Petro-Canada and involuntary termination benefits. As at December 31, 2009, $118 million of actual expenses had been charged against these provisions.

$3,019 million of the goodwill has been allocated to the Oil Sands segment and the remaining $159 million has been allocated to the Refining and Marketing segment. No amount that is part of goodwill is expected to be deductible for tax purposes.

(e) Pre-Existing Contract with Petro-Canada

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

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

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

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

3. CHANGE IN SEGMENTED DISCLOSURES

As a result of the business combination described in note 2, the company has reclassified its operations into the following segments.

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

Natural Gas includes exploration and production of natural gas, crude oil and natural gas liquids, primarily in Western Canada.

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

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

Refining and Marketing includes the purchase and sale of crude oil, the refining of crude oil products, and the distribution and marketing of these and other purchased products through refineries located in Eastern and Western Canada and the U.S., as well as a lubricants plant located in Eastern Canada. Energy supply and trading activities that were previously included in the Refining and Marketing segment are now included within Corporate, Energy Trading and Eliminations.

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

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

4. 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 (hedge) 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.

The recent merger has provided Suncor with the ability to capitalize on future trading opportunities due to increased transactional and trading capacity. The company determined that new transaction levels for certain physical trading commodity contracts exceeded the company's expected purchase, sale or usage requirements. Effective October 1, 2009, these contracts are now considered derivative financial instruments whereby realized and unrealized gains and losses, and the underlying settlement of these contracts is recognized and reported on a net basis in Energy 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.

Forwards and futures are contracts to purchase or sell a specific item at a specified date and price. When used as hedges, forwards and futures help to manage the exposure to losses that could result if commodity prices, foreign currency exchange rates, or interest rates change adversely.

An option is a contract where its holder, for a fee, has purchased the right (but not the obligation) to buy or sell a specified item at a fixed price during a specified period. Options used as hedges help to protect against adverse changes in commodity prices, interest rates, or foreign currency exchange rates.

A costless collar is a combination of two option contracts that limit the holder's exposure to changes in prices to within a specific range. The "costless" nature of this derivative is achieved by buying a put option (the right to sell) for consideration equal to the premium received from selling a call option (the right to purchase).

A swap is a contract where two parties exchange commodity, currency, interest or other payments in order to alter the nature of the payments. For example, fixed interest rate payments on debt may be converted to payments based on a floating interest rate.

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 has elected to use hedge accounting on certain derivatives linked to future commodity and financial transactions.

Financial Instruments

(a) Balance Sheet Financial Instruments

The company's financial instruments in the Consolidated Balance Sheets consist of cash and cash equivalents, accounts receivable, derivative contracts, substantially all current liabilities (except for the current portions of income 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 recognized financial instruments have been determined based on the company's assessment of available market information and appropriate valuation methodologies based on industry accepted third-party models; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The company's fixed-term debt is accounted for under the amortized cost method, with the exception of the portion of debt that has related financial hedges which is accounted for under the fair value methodology discussed below. Upon initial recognition, the cost of the debt is its fair value, adjusted for any associated transaction costs. We do not recognize gains or losses arising from changes in the fair value of this debt until the gains or losses are realized. Gains or losses on our U.S. dollar denominated long-term debt resulting from changes in the exchange rate are recognized in the period in which they occur. At December 31, 2009, the carrying value of our fixed-term debt accounted for under the amortized cost method was $10.1 billion (December 31, 2008 – $6.7 billion) and the fair value at December 31, 2009 was $10.7 billion (December 31, 2008 – $5.4 billion).

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

Fair Value Hedges

The company periodically enters into derivative financial instrument contracts such as interest rate swaps as part of its risk management strategy to manage its exposure to benchmark interest rate fluctuations. The interest rate swap contracts involve an exchange of floating rate versus fixed rate interest payments between the company and investment grade counterparties. The differentials on the exchange of periodic interest payments are recognized in earnings as an adjustment to interest expense. The fair value of the underlying debt is adjusted by the fair value change in the derivative financial instrument with the offset to interest expense. At December 31, 2009, the company had interest rate swaps classified as fair value hedges outstanding for up to two years relating to $200 million of its fixed-rate debt. There was no ineffectiveness recognized on interest rate swaps designated as fair value hedges during the year ended December 31, 2009 (no ineffectiveness during the year ended December 31, 2008). The fair value of interest rate swap contracts outstanding at December 31, 2009 is detailed in note 17.

The company periodically enters into derivative contracts to hedge risks specific to individual transactions. The differentials between the fair value of the hedged transactions and the fair value of the derivative contracts are recognized in earnings as an adjustment to operating revenues. There was no earnings impact associated with hedge ineffectiveness on derivative contracts to hedge risks specific to individual transactions during the year ended December 31, 2009 (2008 – loss of $4 million, net of income taxes of $2 million).

Cash Flow Hedges

The company operates in a global industry where the market price of its petroleum and natural gas products is largely determined based on floating benchmark indices. The company periodically enters into derivative financial instrument contracts such as forwards, futures, swaps, options and costless collars to hedge against the potential adverse impact of changing market prices due to changes in the underlying indices. Specifically, the company manages crude sales price variability by entering into West Texas Intermediate (WTI) derivative transactions, and manages variability in market interest rates and foreign exchange rates during periods of debt issuance through the use of interest rate locks and foreign exchange forward contracts.

There was no earnings impact associated with realized and unrealized hedge ineffectiveness on derivative contracts designated as cash flow hedges during the years ended December 31, 2009 and December 31, 2008.

Certain derivative contracts do not require the payment of premiums or cash margin deposits prior to settlement. On settlement, these contracts result in cash receipts or payments by the company for the difference between the contract and market rates for the applicable dollars and volumes hedged during the contract term. Such cash receipts or payments offset corresponding decreases or increases in the company's sales revenues or crude oil purchase costs. For collars, if market rates are not different than, or are within the range of contract prices, the options contracts making up the collar will expire with no exchange of cash.

Fair Value of Hedging Derivative Financial Instruments

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

($ millions)	**December 31 2009**	December 31 2008
Revenue hedge swaps and collars [b]	**—**	(2)
Fixed to floating interest rate swaps [a]	**18**	25
Specific hedges of individual transactions [b]	**—**	(11)
Fair value of outstanding hedging derivative financial instruments	**18**	12

(a) As at December 31, 2009, $10 million is recorded in accounts receivable (2008 – $9 million) and $8 million is recorded in other assets (2008 – $16 million) in the Consolidated Balance Sheets.

(b) As at December 31, 2009, $nil is recorded in accounts payable and accrued liabilities (2008 – $13 million) in the Consolidated Balance Sheets.

Accumulated Other Comprehensive Income (AOCI)

A reconciliation of changes in AOCI attributable to derivative hedging activities for the year ending December 31 is as follows:

($ millions)	**2009**	2008
AOCI attributable to derivative hedging activities, beginning of the period, net of income taxes of $5 (2008 – $4)	**13**	13
Current year net changes arising from cash flow hedges, net of income taxes of $nil (2008 – $2)	**—**	(7)
Net unrealized hedging losses (gains) at the beginning of the year reclassified to earnings during the period, net of income taxes of $nil (2008 – $3)	**2**	7
AOCI attributable to derivative hedging activities, at December 31, net of income taxes of $5 (2008 – $5)	**15**	13

(c) Derivatives

Commodity Price Risk Derivatives

The company also periodically enters into derivative financial instruments such as options, basis swaps, and heat rate swaps that either do not qualify for hedge accounting treatment or hedges that the company has not elected to document as part of a qualifying hedge relationship. Changes in fair value of these derivative financial instruments are immediately recorded as a gain or loss in the same revenue or expense account where the hedged transaction is recorded. The earnings impact associated with these contracts for the year ended December 31, 2009, was a loss of $763 million, net of income taxes of $261 million (2008 – a gain of $348 million, net of income taxes of $142 million).

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

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

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

(2) Premium paid was US$29.5 million.

(3) Premium received was US$213 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 and marketing revenues. These energy contracts are comprised of crude oil, natural gas and refined products contracts. Financial and physical energy trading activities are accounted for using the mark-to-market method, with the associated gains and losses and the underlying settlement of these contracts recognized and reported on a net basis in Energy Supply and Trading Activities Revenue in the Consolidated Statements of Earnings.

The earnings impact associated with these contracts for the year ended December 31, 2009, was a loss of $52 million, net of income taxes of $18 million (2008 – a gain of $90 million, net of income taxes of $37 million).

Fair Value of Non-Designated Derivative Financial Instruments

The fair values of the derivative assets and liabilities above are as follows:

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

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

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

Change in fair value of net assets

($ millions)	**2009**
Fair value of contracts at December 31, 2008	621
Fair value of contracts realized during the period	**448**
Fair value of contracts entered into during the period	**(983)**
Changes in fair value during the period	**(445)**
Fair value of contracts outstanding at December 31, 2009	**(359)**

(d) Fair Value of Financial Instruments

To estimate fair value of financial instruments, the company uses quoted market prices when available, or industry accepted third-party models and valuation methodologies that utilize observable market data. In addition to market information, the company incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. The company characterizes inputs used in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction. The three levels of the fair value hierarchy are as follows:

- Level 1 – inputs represent quoted prices in active markets for identical assets or liabilities (for example, exchange-traded commodity derivatives). Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – inputs other than quoted prices included within Level 1 that are observable, either directly or indirectly, as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, market interest rates, and volatility factors, which can be observed or corroborated in the marketplace. The company obtains information from sources such as the New York Mercantile Exchange and independent price publications.
- Level 3 – inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value.

In forming estimates, the company utilizes the most observable inputs available for valuation purposes. If a fair value measurement reflects inputs of different levels within the hierarchy, the measurement is categorized based upon the lowest level of input that is significant to the fair value measurement. The valuation of over-the-counter financial swaps and collars is based on similar transactions observable in active markets or industry standard models that primarily rely on market observable inputs. Substantially all of the assumptions for industry standard models are observable in active markets throughout the full term of the instrument. These are categorized as Level 2.

The following table presents the company's material assets and liabilities measured at fair value for each hierarchy level as of December 31, 2009:

($ millions)	Level 1	Level 2	Level 3	Total Fair Value
Designated hedge financial instruments	—	18	—	**18**
Other derivative financial instruments	(13)	(348)	2	**(359)**
Total	**(13)**	**(330)**	**2**	**(341)**

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

1) Market Risk

Market risk is the risk or uncertainty arising from possible market price movements and their impact on the future performance of the business. The market price movements that could adversely affect the value of the company's financial assets, liabilities and expected future cash flows include commodity price risk (crude oil, natural gas and electricity price), foreign currency exchange risk and interest rate risk.

(a) Commodity Price Risk

The company's financial performance is closely linked to crude oil prices (including pricing differentials for various product types), and to a lesser extent, natural gas and electricity prices. The company's policies permit the use of various financial instruments in managing these price exposures. Our strategic crude oil hedging program gives management approval to fix a price or range of prices for portions of the total crude oil planned production for specified periods of time.

A key component of our overall business strategy is to produce sufficient natural gas to meet or exceed internal demands for natural gas purchased for consumption at our North American operations, thus creating a price hedge which reduces our exposure to natural gas price volatility. In addition, existing corporate policies also permit the hedging of natural gas exposures to manage regional price differentials and pricing indexes as identified.

Changes in commodity prices on our financial contracts would have the following impact on our net earnings and other comprehensive income for the year ended December 31, 2009:

Sensitivity Analysis

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

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

(b) Foreign Currency Exchange Risk

The company is exposed to changes in foreign exchange rates as revenues, capital expenditures, or financial instruments may fluctuate due to changing rates. As crude oil, the company's primary product, is priced in U.S. dollars, fluctuations in US$/Cdn$ exchange rates may have a significant impact on revenues. The company's exposure is partially offset through the issuance of U.S. dollar denominated long-term debt (refer to note 17) and by sourcing capital projects in U.S. dollars. The company does not currently hedge foreign currency risk on estimated revenues. The effect of a $0.01 change in the December 31, 2009 US$/Cdn$ exchange rate would change after-tax earnings by approximately $75 million and after-tax other comprehensive income by approximately $40 million for the year ended December 31, 2009.

Where an operating unit has substantial exposure to capital expenditures in currencies other than the U.S. dollar, the company may hedge these risks through a combination of forward and option instruments. Transactions in the applicable financial market are executed consistent with established risk management policies.

(c) Interest Rate Risk

The company is exposed to interest rate risk as changes in interest rates may affect future cash flows and the fair values of its financial instruments. The primary exposure is related to our revolving-term debt (commercial paper, bankers' acceptances and London Interbank Offered Rate (LIBOR) loans). The company seeks to optimize this risk through the use of interest rate swaps by swapping fixed rates of interest for variable rates (see – Fair Value Hedges on page 75) and other derivative instruments.

To optimize the company's position with respect to interest expense, the company targets 30% to 50% of total debt to be exposed to floating interest rates. Over time this floating/fixed rate mix will fluctuate based on prevailing market conditions and management's assessment of overall risk.

The proportion of floating interest rate exposure inclusive of interest rate swaps at December 31, 2009 was 25% of total debt outstanding (December 31, 2008 – 15%). The weighted-average interest rate on total debt for the year ending December 31, 2009 was 5.6% (December 31, 2008 – 5.9%).

The company's cash flows are sensitive to changes in interest rates on the floating rate portion of the company's debt. If the interest rates applicable to floating rate instruments were to have increased by 1%, it is estimated that the company's cash flow for the year ended December 31, 2009 would decrease by approximately $34 million and earnings would decrease by approximately $27 million. This assumes that the amount and mix of fixed and floating rate debt remains unchanged from December 31, 2009, and that the change in interest rates is effective from the beginning of the year.

2) Liquidity Risk

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with financial liabilities. The company believes that it has access to sufficient capital through internally generated cash flows and external sources (bank credit markets and debt capital markets), and to undrawn committed borrowing facilities to meet current spending forecasts.

Surplus cash is invested into a range of short-dated money market securities and the company seeks to ensure the security and liquidity of those investments. Investments are only permitted in high credit quality government or corporate securities. Diversification of these investments is supported through maintaining counterparty credit limits.

The following table shows the timing of cash outflows relating to trade and other payables and finance debt.

	December 31, 2009		December 31, 2008	
($ millions)	Trade and other payables (1)	Finance debt (2)	Trade and other payables (1)	Finance debt (2)
Within one year	**6 529**	**3 796**	3 181	1 378
1 to 3 years	**653**	**1 811**	335	1 377
3 to 5 years	**—**	**1 591**	—	822
Over 5 years	**—**	**18 900**	16	13 387
Total	**7 182**	**26 098**	3 532	16 964

(1) Includes the Fort Hills purchase obligation and the Libya EPSAs signature bonus.
(2) Finance debt includes principal and interest payments on long-term debt and capital lease payments.

3) Credit Risk

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due causing a financial loss. We have a credit policy that is designed to ensure there is a standard credit practice throughout the company to measure and monitor credit risk. The policy outlines delegation of authority, the due diligence process required to approve a new customer or counterparty and the maximum amount of credit exposure per single entity. Before transactions begin with a new customer or counterparty, its creditworthiness is assessed, a credit rating is assigned and a maximum credit limit is allocated. The assessment process is outlined in the credit policy and considers both quantitative and qualitative factors. The company constantly monitors the exposure to any single customer or counterparty along with the financial position of the customer or counterparty. If it is deemed that a customer or counterparty has become materially weaker, the company will work to reduce the credit exposure and lower the credit limit allocated. Regular reports are generated to monitor credit risk and the Credit Committee meets quarterly to ensure compliance with the credit policy and review the exposures.

A substantial portion of the company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risk. At December 31, 2009, substantially all of the company's trade receivables were current, and there were no counterparties that individually constituted more than 10% of the outstanding balance.

The company may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to meet the terms of the contracts. The company's exposure is limited to those counterparties holding derivative contracts with positive fair values at the reporting date. At December 31, 2009, the company's exposure was $231 million (December 31, 2008 – $659 million).

5. ENERGY SUPPLY AND TRADING ACTIVITIES

($ millions)	**December 31 2009**	December 31 2008	December 31 2007
Settlement of non-trading physical contracts[(1)]	**8 008**	11 295	2 931
Settlement of trading physical contracts[(1)]	**20**	—	—
Gains (losses) on trading derivatives[(1)]	**(70)**	127	(39)
Gains on inventory valuation[(1)]	**47**	—	—
Less: Intercompany eliminations	**(428)**	(102)	(110)
Energy Supply and Trading Activities Revenue	**7 577**	11 320	2 782
Settlement of non-trading physical contracts[(1)]	**7 929**	11 331	2 871
Less: Intercompany eliminations	**(548)**	(8)	(1)
Energy Supply and Trading Activities Expense	**7 381**	11 323	2 870

(1) As described in Note 4, certain physical trading strategies are no longer being used for the company's expected purchase, sale or usage requirements. Effective October 1, 2009, contracts within these strategies are now considered derivative financial instruments whereby realized and unrealized gains and losses, and the underlying settlement of these contracts, is recognized and reported on a net basis in Energy Supply and Trading Activities Revenue. Prior to October 1, 2009, the settlement of these contracts was recorded on a gross basis within Energy Supply and Trading Activity Revenue and Energy Supply and Trading Activity Expense.

6. FINANCING EXPENSES (INCOME)

($ millions)	**2009**	2008	2007
Interest on debt	**573**	352	189
Capitalized interest	**(136)**	(352)	(189)
Interest expense	**437**	—	—
Foreign exchange loss (gain) on long-term debt	**(858)**	919	(252)
Other foreign exchange (gain) loss	**(66)**	(2)	41
Total financing expenses (income)	**(487)**	917	(211)

Cash interest payments in 2009 totalled $581 million (2008 – $328 million; 2007 – $183 million).

7. INCOME TAXES

The assets and liabilities shown on Suncor's balance sheets are calculated in accordance with Canadian GAAP. Suncor's income taxes are calculated according to government tax laws and regulations, which results in different values for certain assets and liabilities for income tax purposes. These differences are known as ***temporary differences****, because eventually these differences will reverse.*

The amount shown on the balance sheets as ***future income taxes*** *represent income taxes that will eventually be payable or recoverable in future years when these temporary differences reverse.*

See below for more technical details and amounts.

The provision for income taxes reflects an effective tax rate that differs from the statutory tax rate. A reconciliation of the provision for income taxes is as follows:

($ millions)	**2009**	2008	2007
Earnings before income tax	**1 289**	3 132	3 549
Canadian statutory tax rate	**30.95%**	29.52%	32.14%
Statutory tax	**399**	925	1 141
Add (deduct) the tax effect of:			
Non-taxable component of capital gains and losses	**(133)**	136	(40)
Stock-based compensation and other permanent items	**42**	36	33
Assessments and adjustments	**(42)**	(48)	(1)
Effect of changes to statutory enacted rates	**(148)**	—	(427)
Impact of income tax rate adjustments on future income tax liabilities	**152**	—	—
Change in valuation allowance	**(59)**	—	—
Canadian tax rate differential	**(27)**	(113)	(145)
Foreign tax rate differential	**84**	12	23
Non-taxable gain on effective settlement of pre-existing contract with Petro-Canada (note 2(e))	**(105)**	—	—
Other	**(20)**	47	(18)
Provision for income taxes	**143**	995	566

At December 31, geographic distribution of current income tax provisions were as follows:

($ millions)	**2009**	2008	2007
Provision for (recovery of) Income Taxes:			
Current:			
Canada	**599**	493	271
Foreign	**269**	21	111
Future:			
Canada	**(702)**	515	142
Foreign	**(23)**	(34)	42
Total provision for income taxes	**143**	995	566

The provisions for current and future income taxes include tax recoveries (expenses), which are largely due to changes to income tax rates. These amounts have been allocated to the business segments as follows:

($ millions)	**2009**	2008	2007
Oil Sands	**103**	—	413
Natural Gas	**8**	—	39
East Coast Canada	**20**	—	—
Refining and Marketing	**19**	—	17
Corporate, Energy Trading and Eliminations	**(2)**	—	(42)
	148	—	427

In 2009, net income tax payments totalled $872 million (2008 – $638 million; 2007 – $152 million).

At December 31, future income taxes were comprised of the following:

($ millions)	**2009**	2008	2007
Future income tax liabilities:			
Property, plant and equipment	**9 670**	4 987	4 467
Risk management and energy trading	**—**	149	—
Other	**177**	48	86
Future income tax assets:			
Asset retirement obligations	**(813)**	(400)	(269)
Employee future benefits	**(352)**	(72)	(118)
Risk management and energy trading	**(113)**	—	—
Other Assets	**(206)**	(7)	37
Net Future income tax liabilities	**8 363**	4 705	4 203
Less: Current portion of future income tax (assets)/liabilities	**(314)**	90	(9)
Future income tax liabilities	**8 677**	4 615	4 212

Deferred distribution taxes associated with International business operations have not been recorded. Based on current plans, repatriation of funds in excess of foreign reinvestment will not result in material additional income tax expense.

Complex income tax issues, which involve interpretation of continually changing regulations, are encountered in computing the provision for income taxes. Management believes that adequate provisions have been made for all such outstanding issues and the resolution of these issues would not materially affect the financial position or results of operation of the company,

8. EARNINGS PER COMMON SHARE

The following is a reconciliation of basic and diluted net earnings per common share:

($ millions)	**2009**	2008	2007
Net earnings	**1 146**	2 137	2 983
(millions of common shares)			
Weighted-average number of common shares	**1 198**	932	922
Dilutive securities:			
Shares issued under stock-based compensation plans	**13**	13	20
Weighted-average number of diluted common shares	**1 211**	945	942
(dollars per common share)			
Basic earnings per share [(a)]	**0.96**	2.29	3.23
Diluted earnings per share [(b)]	**0.95**	2.26	3.17

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 the net earnings attributable to common shareholders divided by the weighted-average number of common shares.

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

9. CASH AND CASH EQUIVALENTS

($ millions)	**2009**	2008
Cash	**205**	30
Short-term investments	**300**	630
	505	660

10. CHANGES IN NON-CASH WORKING CAPITAL RELATING TO OPERATING ACTIVITIES

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

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

($ millions)	**2009** [1]	2008	2007
Operating activities			
Accounts receivable	**123**	226	(374)
Inventories	**(585)**	103	(223)
Accounts payable and accrued liabilities	**282**	186	207
Income taxes payable/receivable	**(44)**	(110)	246
	(224)	405	(144)

(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.

11. INVENTORIES

($ millions)	**2009**	2008
Crude oil	**781**	459
Refined products	**1 303**	247
Materials, supplies and merchandise	**532**	203
Energy trading commodity inventories [1]	**355**	—
Total	**2 971**	909

(1) As described in note 4, certain physical trading commodity contracts are no longer being used for the company's expected purchase, sale or usage requirements. Inventories related to these derivative contracts are now recorded at fair value less costs to sell with the associated gains and losses and the underlying settlement of the inventory recorded on a net basis in Energy Supply and Trading Activities revenue.

During 2009, inventories of $14.9 billion (2008 – $15.7 billion) were expensed. There were no write-downs of inventories in 2009 (2008 – $40 million) and no reversals of write-downs were recorded in 2009 and 2008.

12. OTHER ASSETS

($ millions)	**2009**	2008
Unrealized mark-to-market gains on commodity derivatives	**6**	273
Intangible assets [1]	**233**	—
Investments	**148**	23
Other	**149**	92
Total	**536**	388

(1) In 2009, $236 million of intangible assets were acquired through the business combination with Petro-Canada. $166 million of these assets relate to the Petro-Canada brand and have an indefinite life, and $70 million relate to customer lists which will be amortized over their estimated useful lives which range from five to ten years. Amortization expense recognized for the year ended December 31, 2009 related to intangible assets was $4 million (2008 – nil).

13. PROPERTY, PLANT AND EQUIPMENT

($ millions)	2009 Cost	2009 Accumulated Provision	2008 Cost	2008 Accumulated Provision
Oil Sands				
Oil and gas properties	**5 224**	**448**	2 021	285
Plant and equipment	**19 012**	**3 677**	14 184	2 988
Assets not subject to depreciation or depletion[1]	**12 551**	**—**	11 107	—
	36 787	**4 125**	27 312	3 273
Natural Gas				
Oil and gas properties	**5 925**	**1 613**	2 584	1 213
Plant and equipment	**351**	**118**	219	100
Assets not subject to depreciation or depletion[1]	**24**	**—**	211	—
	6 300	**1 731**	3 014	1 313
East Coast Canada			—	—
Oil and gas properties	**3 463**	**207**	—	—
Plant and equipment	**49**	**1**	—	—
Assets not subject to depreciation or depletion[1]	**1 360**	**—**	—	—
	4 872	**208**	—	—
International				
Oil and gas properties	**4 130**	**271**	—	—
Plant and equipment	**53**	**31**	—	—
Assets not subject to depreciation or depletion[1]	**4 294**	**—**	—	—
	8 477	**302**	—	—
Refining and Marketing				
Plant and equipment	**8 312**	**1 654**	4 049	1 313
Assets not subject to depreciation or depletion[1]	**503**	**—**	215	—
	8 815	**1 654**	4 264	1 313
Corporate	**419**	**165**	329	138
	65 670	**8 185**	34 919	6 037
Net property, plant and equipment		**57 485**		28 882

(1) Consists of work in progress, development assets, and assets under construction which are not currently being depreciated or depleted.

At December 31, 2009, capital leases at a net cost of $225 million (December 31, 2008 – $91 million) and $48 million are included in the assets of Oil Sands and East Coast Canada, respectively.

14. EMPLOYEE FUTURE BENEFITS LIABILITY

Suncor employees are eligible to receive certain pension, health care and insurance benefits when they retire under the terms of the company's defined benefit and defined contribution plans. The related ***Benefit Obligation*** *or commitment that Suncor has to employees and retirees at December 31, 2009, was $3 279 million (2008 – $955 million).*

As required by government regulations, Suncor sets aside funds with an independent trustee to meet certain of the defined benefit pension obligations. The company funds its unregistered supplementary pension plan and supplementary senior executive retirement plan on a voluntary basis. The amount and timing of future funding for these supplementary plans is subject to capital availability and is at the company's discretion. At the end of December 2009, ***Plan Assets*** *to meet the* ***Benefit Obligation*** *were $2 072 million (2008 – $613 million).*

The excess of the ***Benefit Obligation*** *over* ***Plan Assets*** *of $1 207 million (2008 – $342 million) represents the* ***Net Unfunded Obligation****.*

The company also provides a number of defined contribution plans, including a U.S. 401(k) savings plan, that provide for an annual contribution of 5% to 8% of each participating employee's pensionable earnings.

Defined Benefit Pension Plans and Other Post-Retirement Benefits

The company's defined benefit pension plans provide non-indexed pension benefits at retirement based on years of service and final average earnings. These obligations are met through funded registered retirement plans and through unregistered supplementary pensions and senior executive retirement plans that are voluntarily funded through retirement compensation arrangements, and/or paid directly to recipients. Company contributions to the funded plans are deposited with independent trustees who act as custodians of the plans' assets, as well as the disbursing agents of the benefits to recipients. Plan assets are managed by a pension committee on behalf of beneficiaries. The committee retains independent managers and advisors.

Funding of the registered retirement plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, depending on funding status, and every year in the United States. The most recent valuation for the Canadian plans was performed as at December 31, 2009 and the next required valuation will be as of December 31, 2012.

The company's other post-retirement benefits programs are unfunded and include certain health care and life insurance benefits provided to retired employees and eligible surviving dependants.

The expense and obligations for both funded and unfunded benefits are determined in accordance with Canadian GAAP and actuarial principles. Obligations are based on the projected benefit method of valuation that includes employee service to date and present pay levels, as well as a projection of salaries and service to retirement.

Defined Benefit Obligations and Funded Status

The following table presents information about obligations recognized in the Consolidated Balance Sheets and the funded status of the plans at December 31:

	Pension Benefits		Other Post-Retirement Benefits	
($ millions)	**2009**	2008	**2009**	2008
Change in benefit obligation				
Benefit obligation at beginning of year	**806**	901	**149**	162
Plan acquisition upon merger[(a)]	**1 912**	—	**265**	—
Service costs	**64**	56	**6**	4
Interest costs	**96**	49	**15**	9
Plan participants' contributions	**17**	9	**—**	—
Foreign exchange	**(13)**	8	**(4)**	4
Actuarial (gain) loss	**59**	(168)	**1**	(27)
Benefits paid	**(86)**	(49)	**(8)**	(3)
Benefit obligation at end of year[(b)(e)]	**2 855**	806	**424**	149
Change in plan assets[(c)]				
Fair value of plan assets at beginning of year	**613**	684	**—**	—
Plan acquisition upon merger	**1 255**	—		—
Actual return (loss) on plan assets	**175**	(107)	**—**	—
Employer contributions	**105**	72	**—**	—
Foreign exchange	**(7)**	4	**—**	—
Plan participants' contributions	**17**	9	**—**	—
Benefits paid	**(86)**	(49)	**—**	—
Fair value of plan assets at end of year[(e)]	**2 072**	613	**—**	—
Net unfunded obligation	**(783)**	(193)	**(424)**	(149)
Items not yet recognized in earnings:				
Unamortized net actuarial loss[(d)]	**50**	123	**8**	12
Unamortized past service costs	**9**	—	**(14)**	(17)
Accrued benefit liability	**(724)**	(70)	**(430)**	(154)
Current liability	**(30)**	(37)	**(3)**	(3)
Long-term liability	**(701)**	(40)	**(427)**	(151)
Long-term asset	**7**	7	**—**	—
Total accrued benefit liability	**(724)**	(70)	**(430)**	(154)

(a) The valuation of accrued benefit obligations for plans acquired through the business combination with Petro-Canada assumed a discount rate of 5.25%, a rate of compensation increase of 3.00% and an expected return on plan assets rate of 6.75%.

(b) Obligations are based on the following assumptions:

(percent)	Pension Benefit Obligations 2009	2008	Other Post-Retirement Benefits Obligations 2009	2008
Discount rate	**5.85**	6.50	**6.00**	6.50
Rate of compensation increase	**3.90**	5.00	**4.00**	4.75

Assumed health care cost trend rates may have a significant effect on the amounts reported for other post-retirement benefit obligations. A one percent change in assumed health care cost trend rates would have the following effects:

($ millions)	**1% increase**	1% decrease
Increase (decrease) to total of service and interest cost components of net periodic post-retirement health care benefit cost	2	(2)
Increase (decrease) to the health care component of the accumulated post-retirement benefit obligation	34	(28)

(c) Pension plan assets are not the company's assets and therefore are not included in the Consolidated Balance Sheets.

(d) The unamortized net actuarial loss represents annually calculated differences between actual and projected plan performance. These amounts are amortized as part of the net periodic benefit cost over the expected average remaining service life of employees of 7 years for pension benefits (2008 – 11 years; 2007 – 11 years), and over the expected average future service life to full eligibility age of 11 years for other post-retirement benefits (2008 – 11 years; 2007 – 12 years).

(e) The company uses a measurement date of December 31 to value the plan assets and accrued benefit obligation.

The above benefit obligation at year-end includes partially funded and unfunded plans, as follows:

($ millions)	Pension Benefits 2009	2008	Other Post-Retirement Benefits 2009	2008
Partially funded plans	**2 855**	806	**—**	—
Unfunded plans	**—**	—	**424**	149
Benefit obligation at end of year	**2 855**	806	**424**	149

Benefit Plans Expense

($ millions)	Pension Benefits 2009	2008	2007	Other Post-Retirement Benefits 2009	2008	2007
Current service costs	**64**	56	51	**6**	4	4
Interest costs	**96**	49	45	**15**	9	8
Actual (return) loss on plan assets [i]	**(175)**	107	(7)	**—**	—	—
Actuarial (gain) loss	**59**	(168)	(28)	**1**	(27)	(4)
Pension expense before adjustments for the long-term nature of employee future benefit costs	**44**	44	61	**22**	(14)	8
Difference between actual and expected return on plan assets [i]	**98**	(152)	(35)	**—**	—	—
Difference between actual and recognized actuarial losses	**(36)**	188	51	**3**	33	10
Difference between actual and recognized past service costs	**2**	2	2	**(3)**	(3)	(3)
Defined benefit plans expense [ii]	**108**	82	79	**22**	16	15
Defined contribution plans expense	**28**	15	13	**—**	—	—
Total benefit plans expense	**136**	97	92	**22**	16	15

(i) The expected return on plan assets is the expected long-term rate of return on plan assets for the year. It is based on plan assets at the beginning of the year that have been adjusted on a weighted-average basis for contributions and benefit payments expected for the year. The expected return on plan assets is included in the net periodic benefit cost for the year to which it relates, while the difference between it and the actual return realized on plan assets in the same year is amortized over the expected average remaining service life of employees of 7 years for pension benefits.

To estimate the expected long-term rate of return on plan assets, the company considered the current level of expected returns on the fixed income portion of the portfolio, the historical level of the risk premium associated with other asset classes in which the portfolio is invested and the expectation for future returns on each asset class. The expected return for each asset class was weighted based on the policy asset mix to develop an expected long-term rate of return on asset assumption for the portfolio.

(ii) Defined benefit plans pension expense is based on the following assumptions:

(percent)	Pension Benefit Expense **2009**	2008	2007	Other Post-Retirement Benefits Expense **2009**	2008	2007
Discount rate	**6.50**	5.25	5.00	**6.00**	5.25	5.00
Expected return on plan assets	**6.70**	6.50	6.50	**N/A**	N/A	N/A
Rate of compensation increase	**3.90**	5.00	5.00	**4.00**	4.75	4.75

Plan Assets and Investment Objectives

The company's long-term investment objective is to secure the defined pension benefits while managing the variability and level of its contributions. The portfolio is rebalanced periodically as required, while ensuring that the maximum equity content is 65% at any time. Plan assets are restricted to those permitted by legislation, where applicable. Investments are made through pooled, mutual, segregated or exchange traded funds.

The company's weighted-average pension plan asset allocation based on market values as at December 31, 2009 and 2008, and the target allocation for 2010, are as follows:

Asset Category	Target Allocation % 2010	Plan Assets % **2009**	2008
Equities	57	**59**	57
Fixed income	43	**41**	43
Total	100	**100**	100

Equity securities do not include any direct investments in Suncor shares.

Cash Flows

The company expects that cash contributions to its defined benefit pension plans in 2010 will be $133 million. Expected benefit payments from all of the plans are as follows:

	Pension Benefits	Other Post-Retirement Benefits
2010	136	18
2011	145	19
2012	153	21
2013	163	23
2014	170	24
2015 – 2019	963	141
Total	1 730	246

15. SHARE CAPITAL

Authorized

Common Shares

The company is authorized to issue an unlimited number of common shares without nominal or par value.

Preferred Shares

The company is authorized to issue an unlimited number of preferred shares in series, without nominal or par value.

Issued

	Common Shares	
	Number (thousands)	Amount ($ millions)
Balance as at December 31, 2006	919 888	794
Issued for cash under stock option plans	5 388	74
Issued under dividend reinvestment plan	290	13
Balance as at December 31, 2007	925 566	881
Issued for cash under stock options plan	9 823	226
Issued under dividend reinvestment plan	135	6
Balance as at December 31, 2008	935 524	1 113
Shares issued to Petro-Canada shareholders (note 2)	**621 142**	**18 878**
Issued for cash under stock options plan	**2 968**	**57**
Issued under dividend reinvestment plan	**144**	**5**
Balance as at December 31, 2009	**1 559 778**	**20 053**

Stock-Based Compensation

A stock option gives the holder the right, but not the obligation, to purchase common shares at a predetermined price over a specified period of time.

After the date of grant, employees and non-employee directors that hold options must earn the right to exercise them. The holder must fulfill a time requirement for service to the company, at which time the option is considered vested. Certain options are subject to accelerated vesting should the company meet predetermined performance criteria.

The predetermined price at which an option can be exercised is equal to or greater than the market price of the common shares on the date the option is granted.

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

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

A performance share unit (PSU) is a time-vested award entitling employees to receive cash to varying degrees contingent upon the company's shareholder return relative to a peer group of companies.

A restricted share unit (RSU) is a time-vested award entitling employees to receive cash based on the company's share price at time of vesting.

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

(a) Stock Option Plans:

(i) SunShare 2012 Performance Stock Option Plan

Granting of options under this plan ended on July 31, 2009. The company granted 1,204,000 options in 2009 (2008 – 2,637,000, 2007 – 15,686,000) to all eligible permanent full-time and part-time employees, both executive and non-executive, under its SunShare 2012 performance stock option plan. On January 1, 2010, 25% of the outstanding options vested and the remaining 75% of outstanding options may vest on January 1, 2013 if certain specified performance targets are met. All unvested options at January 1, 2013, which have not previously expired or been cancelled will automatically expire.

(ii) Executive Stock Plan

Granting of options under this plan ended on July 31, 2009. Under this plan, the company granted 711,000 common share options in 2009 (2008 – 895,000; 2007 – 958,000) to non-employee directors and certain executives and other senior employees of the company. Options granted have a 10-year life and vest annually over a three-year period.

(iii) Key Contributor Stock Option Plan

Granting of options under this plan ended on July 31, 2009. Under this plan, the company granted 571,000 common share options in 2009 (2008 – 2,375,000; 2007 – 2,370,000) to non-insider senior managers and key employees. Options granted have a 10-year life and vest annually over a three-year period.

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

Granting of options under this plan ended on July 31, 2009. In conjunction with the business combination transaction described in note 2, each outstanding option issued under this plan to purchase Petro-Canada common shares was exchanged on August 1, 2009 for 1.28 options to purchase Suncor common shares, for a total of 29.9 million options outstanding at August 1, 2009. The same exchange ratio was applied to the exercise price of these options.

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

(v) Suncor Energy Inc. Stock Options

This plan replaces the pre-merger stock option plans of legacy Petro-Canada and Suncor. The company granted 4,000 options under this plan, which came into effect on August 1, 2009. Outstanding options that are cancelled, expire or are terminated or otherwise result in no underlying common share being issued will be available for issuance as options under this plan. Options granted have a seven-year life and vest annually over a three-year period.

The following tables cover all common share options granted by the company for the years indicated:

	Number (thousands)	Range of Exercise Prices Per Share ($)	Weighted-Average Exercise Price Per Share ($)
Outstanding, December 31, 2006	39 618	3.89 – 50.90	19.24
Granted	21 104	35.28 – 53.51	46.68
Exercised	(5 388)	3.89 – 46.06	11.38
Forfeited/expired	(1 334)	12.66 – 50.87	32.84
Outstanding, December 31, 2007	54 000	5.06 – 53.51	30.31
Granted	5 907	23.30 – 69.97	50.78
Exercised	(9 823)	5.06 – 50.86	19.69
Forfeited/expired	(3 682)	12.31 – 67.58	41.72
Outstanding, December 31, 2008	46 402	5.06 – 69.97	34.55
Granted	**2 490**	**20.99 – 49.67**	**35.78**
Adjusted options issued to Petro-Canada stock option holders	**29 900**	**8.22 – 44.27**	**28.05**
Exercised	**(2 870)**	**5.06 – 36.68**	**13.69**
Forfeited/expired	**(3 898)**	**13.31 – 71.12**	**40.48**
Outstanding, December 31, 2009	**72 024**	**7.84 – 72.68**	**32.52**
Exercisable, December 31, 2009	**42 755**	**7.84 – 72.68**	**26.16**

Common shares authorized for issuance by the Board of Directors that remain available for the granting of future options, at December 31:

(thousands of common shares)	**2009**	2008	2007
	15 942	12 345	14 570

The following table is an analysis of outstanding and exercisable common share options as at December 31, 2009:

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

Fair Value of Options Granted

The fair values of all legacy Suncor common share options granted during the period and Adjusted Options granted in 2003 are estimated as at the grant date using the Monte Carlo simulation approach for the SunShare 2012 option plan and the Black-Scholes option-pricing model for all other option plans. Adjusted Options which have a CPA granted subsequent to 2003 are accounted for based on the intrinsic value at each period end. The weighted-average fair values of the options granted during the various periods and the weighted-average assumptions used in their determination are as noted below:

	2009	2008	2007
Annual dividend per share	**$0.30**	$0.20	$0.19
Risk-free interest rate	**2.31%**	3.35%	4.22%
Expected life	**5 years**	6 years	6 years
Expected volatility	**47%**	30%	30%
Weighted-average fair value per option	**$10.28**	$13.86	$14.89

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

Grants under this plan ended on July 31, 2009. In conjunction with the business combination described in note 2, each outstanding SAR issued under this plan was exchanged with 1.28 SARs resulting in the addition of 15,353,000 SARs at August 1, 2009. SARS have a seven-year life and vest annually over a four-year period.

Changes in the number of Adjusted SARs outstanding were as follows:

	Number (thousands)	Range of Exercise Prices Per Share ($)	Weighted-Average Exercise Price Per Share ($)
Shares issued to Petro-Canada shareholders (note 2)	**15 353**	**19.13 – 46.13**	**28.74**
Exercised	**(306)**	**19.13 – 39.41**	**35.01**
Forfeited/expired	**(982)**	**19.13 – 46.13**	**28.28**
Outstanding, December 31, 2009	**14 065**	**19.13 – 46.13**	**28.63**
Exercisable, December 31, 2009	**2 740**	**19.13 – 46.13**	**35.45**

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

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

(c) Deferred Share Units (DSUs)

The company had 2,616,000 DSUs outstanding at December 31, 2009 (1,903,000 at December 31, 2008). In conjunction with the business combination described in note 2, each outstanding Petro-Canada DSU was adjusted by 1.28, resulting in the addition of 1,008,000 DSUs at August 1, 2009. DSUs were granted to certain executives under the company's former employee long-term incentive program. Members of the Board of Directors receive one-half, or at their option, all of their compensation in the form of DSUs. DSUs are only redeemable at the time a unitholder ceases employment or Board membership, as applicable.

In 2009, 443,000 DSUs were redeemed for cash consideration of $16 million (2008 – 473,000 redeemed for cash consideration of $30 million; 2007 – 40,000 redeemed for cash consideration of $2 million). Over time, DSU unitholders are entitled to receive additional DSUs equivalent in value to future notional dividend reinvestments.

(d) Performance Share Units (PSUs)

During 2009, the company issued 1,149,000 PSUs (2008 – 795,000; 2007 – 830,000) under its Performance Share Unit Compensation Plan. In conjunction with the business combination described in note 2, each outstanding Petro-Canada PSU was adjusted by 1.28, resulting in the addition of 945,000 PSUs at August 1, 2009. PSUs vest and are settled in cash approximately three years after the grant date to varying degrees (0%, 50%, 100% and 150%) contingent upon Suncor's performance (performance factor). Performance is measured by reference to the company's total shareholder return (stock price appreciation and dividend income) relative to a peer group of companies. Expense related to the PSUs is accrued based on the price of common shares at the end of the period and the anticipated performance factor. This expense is recognized on a straight-line basis over the term of the grant.

(e) Restricted Share Units (RSUs)

In 2009, the company issued 2,715,000 RSUs (2008 – 1,078,000) under the share unit portion of its new employee stock-based compensation plan ("SunShare 2012"). In conjunction with the business combination described in note 2, each outstanding Petro-Canada RSU was adjusted by 1.28, resulting in the addition of 1,018,000 RSUs at August 1, 2009.

Stock-Based Compensation Expense (Recovery)

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

($ millions)	**2009**	2008	2007
Stock option plans	**148**	120	103
Adjusted SARs	**35**	—	—
Performance share units (PSUs)	**30**	(30)	60
Restricted share units (RSUs)	**50**	8	—
Deferred share units (DSUs)	**30**	(51)	21
Total stock based compensation expense	**293**	47	184

16. ACCRUED LIABILITIES AND OTHER

($ millions)	**2009**	2008
Asset retirement obligations[(a)]	**2 888**	1 444
Employee future benefits liability (note 14)	**1 128**	191
Stock-based compensation plans[(b)]	**219**	67
Deferred revenue	**94**	161
Other long-term financial liabilities[(c)]	**602**	—
Other	**131**	123
Total	**5 062**	1 986

(a) Asset Retirement Obligations (ARO)

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the total obligations associated with the retirement of property, plant and equipment.

($ millions)	**2009**	2008
Asset retirement obligations, beginning of year	**1 600**	1 072
Liabilities incurred	**253**	38
Petro-Canada liabilities acquired during the year (note 2)[(1)]	**1 605**	—
Changes in estimates	**(145)**	560
Liabilities settled	**(248)**	(134)
Accretion of asset retirement obligations	**155**	64
Foreign exchange	**(20)**	—
Asset retirement obligations, end of year	**3 200**	1 600
Less: Current portion	**(312)**	(156)
	2 888	1 444

(1) The majority of the asset retirement obligation liability acquired as a result of the merger with Petro-Canada was discounted at August 1, 2009 using the company's long-term credit-adjusted risk-free rate at that time of 6.5%.

The total undiscounted amount of estimated future cash flows required to settle the obligations at December 31, 2009, was approximately $8.3 billion (2008 – $3.5 billion). Substantially all of the liability recognized in 2009 was discounted using the company's long-term credit-adjusted risk-free rate of 6.2% (2008 – 9.0%). The credit-adjusted risk-free rate used reflects the expected timeframe of the related liability. Payments to settle the ARO occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed fifty years. The current portion of asset retirement obligations is included in accounts payable and accrued liabilities.

A significant portion of the company's assets, including the upgrading facilities at the oil sands operation and the downstream refineries, have retirement obligations for which the fair value cannot be reasonably determined because the assets currently have an indeterminate life. The asset retirement obligation for these assets will be recorded in the first period in which the lives of the assets are determinable.

(b) Stock Based Compensation Plans

The portion of the stock based compensation plans expected to be paid within one year is shown within current liabilities and amounts to an additional $10 million (2008 – $8 million). See note 15 for further information on our liability-based stock-based compensation awards.

(c) Other Long-Term Financial Liabilities

As part of the business combination described in Note 2, the company assumed an obligation relating to Petro-Canada's acquisition of an additional 5% interest in the Fort Hills project in 2007 from another partner in the project. To pay for this investment the company will fund $375 million of expenditures in excess of its working interest. Upon the acquisition of Petro-Canada, this obligation was revalued using an estimated payout pattern for the funding, discounted using the company's estimated cost of debt. At December 31, 2009, the carrying amount of the Fort Hills obligation was $322 million.

The company also assumed the remaining US$500 million obligation for a signature bonus relating to Petro-Canada's ratification of six Exploration and Production Sharing Agreements in Libya in 2008, payable in several instalments to be paid through 2013. Upon the acquisition of Petro-Canada, this obligation was revalued using the company's estimated cost of debt.

At December 31, 2009, the carrying amount of the Libya obligation was $511 million, of which the current portion is $231 million and is recorded in accounts payable and accrued liabilities.

17. LONG-TERM DEBT AND CREDIT FACILITIES

($ millions)	**2009**	2008
Fixed-term debt, redeemable at the option of the company		
6.85% Notes, denominated in U.S. dollars, due in 2039 (US$750)[(i)]	**785**	918
6.80% Notes, denominated in U.S. dollars, due in 2038 (US$900)	**972**	—
6.50% Notes, denominated in U.S. dollars, due in 2038 (US$1150)	**1 204**	1 408
5.95% Notes, denominated in U.S. dollars, due in 2035 (US$600)	**578**	—
5.95% Notes, denominated in U.S. dollars, due in 2034 (US$500)	**523**	612
5.35% Notes, denominated in U.S. dollars, due in 2033 (US$300)	**266**	—
7.15% Notes, denominated in U.S. dollars, due in 2032 (US$500)	**523**	612
6.10% Notes, denominated in U.S. dollars, due in 2018 (US$1250)[(i)]	**1 308**	1 531
6.05% Notes, denominated in U.S. dollars, due in 2018 (US$600)	**643**	—
5.00% Notes, denominated in U.S. dollars, due in 2014 (US$400)[(ii)]	**429**	—
4.00% Notes, denominated in U.S. dollars, due in 2013 (US$300)	**313**	—
7.00% Debentures, denominated in U.S. dollars, due in 2028 (US$250)	**271**	—
7.875% Debentures, denominated in U.S. dollars, due in 2026 (US$275)	**325**	—
9.25% Debentures, denominated in U.S. dollars, due in 2021 (US$300)	**402**	—
5.39% Series 4 Medium Term Notes, due in 2037	**600**	600
5.80% Series 4 Medium Term Notes, due in 2018[(iii)]	**700**	700
6.70% Series 2 Medium Term Notes, due in 2011[(iv)]	**500**	500
	10 342	6 881
Revolving-term debt, with interest at variable rates		
Commercial paper[(v)], bankers' acceptances and LIBOR loans (interest rate at December 31, 2009 – 0.7%, 2008 – 2.2%)	**3 244**	934
Total unsecured long-term debt	**13 586**	7 815
Secured long-term debt	**13**	13
Capital leases[(vi)]	**326**	103
Fair value of interest swaps	**18**	25
Deferred financing costs	**(63)**	(72)
	13 880	7 884
Current portion of long-term debt		
Capital leases[(vii)]	**(14)**	(9)
Fair value of interest swaps	**(11)**	(9)
Total current portion of long-term debt	**(25)**	(18)
Total long-term debt	**13 855**	7 866

(i) In June 2008, the company issued 6.10% Notes with a principal amount of US$1.25 billion and 6.85% Notes with a principal amount of US$750 million under an amended US$3.65 billion debt shelf prospectus. These notes bear interest, which is paid semi-annually, and mature on June 1, 2018, and June 1, 2039, respectively. The net proceeds received were added to our general funds, which were used for our working capital needs, sustaining capital expenditures, growth capital expenditures and to repay outstanding commercial paper borrowings.

(ii) These notes, acquired on August 1, 2009 under the merger with Petro-Canada, were originally issued by PC Financial Partnership, a wholly-owned finance subsidiary of Petro-Canada. Suncor has fully and unconditionally guaranteed the notes.

(iii) In May 2008, the company issued 5.80% Medium Term Notes with a principal amount of $700 million under an outstanding $2,000 million debt shelf prospectus. These notes bear interest, which is paid semi-annually, and mature on May 22, 2018. The net proceeds received were added to our general funds to repay outstanding commercial paper, which originally funded our working capital needs, sustaining capital expenditures and growth capital expenditures.

(iv) The company has entered into interest rate swap transactions. The swap transactions result in an average effective interest rate that is different from the stated interest rate of the related underlying long-term debt instruments.

Description of Swap Transaction	Principal Swapped ($ millions)	Swap Maturity	Effective Interest Rate 2009	2008
Swap of 6.70% Medium Term Notes to floating rates	200	2011	2.0%	4.8%

(v) The company is authorized to issue commercial paper to a maximum of $2.5 billion having a term not to exceed 365 days. Commercial paper is supported by available committed credit facilities, (see Credit facilities below).

(vi) Interest rates on capital leases range from 4.7% to 13.4%, and maturity dates range from 2012 to 2037.

Credit facilities

During 2009, the company acquired $4,524 million of available credit facilities in the merger with Petro-Canada. At December 31, 2009, the company had available credit facilities of $8,188 million, of which $4,208 million was unutilized, as follows:

($ millions)	2009
Facility that is fully revolving for 364 days, has a term period of one year and expires in 2010	**61**
Facility that is fully revolving for a period of four years and expires in 2013	**209**
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	**598**
Total available credit facilities	**8 188**
Credit facilities supporting outstanding revolving-term debt	**(3 244)**
Credit facilities supporting standby letters of credit	**(736)**
Total unutilized credit facilities	**4 208**

Certain of the notes and debentures of the company were acquired in the merger described in note 2 and were accounted for at their fair value at the date of acquisition, which was higher than the principal amount. The difference between the fair value and the principal amount of these debts of $121 million is being amortized over the remaining life of the debt acquired.

18. CAPITAL STRUCTURE FINANCIAL POLICIES

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

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

Net debt to cash flow from operations is calculated as short-term debt plus total long-term debt less cash and cash equivalents divided by cash flow from operations for the year then ended.

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 years ended December 31, 2009 and 2008.

The company's strategy during 2009, which was unchanged from 2008, was to maintain the measure set out in the following schedule. The company believes that achieving our capital target helps to provide the company access to capital at a reasonable cost by maintaining solid investment-grade credit ratings. The company operates in a cyclical business environment and ratios may periodically fall outside of management targets.

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

The increase in debt levels as a result of the merger with Petro-Canada on August 1, 2009 has caused our net debt/cash flow from operations measure for the year ended December 31, 2009 to increase significantly, as the calculation only includes five months of cash flow from operations relating to legacy Petro-Canada operations.

(1) Cash flow from operations is expressed before changes in non-cash working capital. Cash flow from operations is the same measure as the cash flow from operating activities before changes in working capital measure that is included in the Consolidated Statements of Cash Flows.

19. COMMITMENTS, CONTINGENCIES, VARIABLE INTEREST ENTITIES, AND GUARANTEES

(a) Operating Commitments

($ millions)	Pipeline Capacity, Energy Services and Delivery Obligations[1]	Operating Leases
2010	714	376
2011	708	212
2012	707	160
2013	688	114
2014	647	101
Later years	7 538	759
Total	11 002	1 722

(1) Includes annual tolls payable under transportation service agreements with major pipeline companies to use a portion of their pipeline capacity and tankage, as applicable, for transportation of product within Canada and the United States.

Suncor has commitments under long-term energy agreements to obtain a portion of the power and the steam generated by certain cogeneration facilities owned by a major third-party energy company and obligations associated with reimbursing BG Gas Marketing for gas quantities as outlined in the Trinidad LNG Sales Contract.

In addition to the operating commitments quantified in the above table, we have other obligations for goods and services and raw materials entered into in the normal course of business, which may terminate on short notice. Commodity purchase obligations for which an active, highly liquid market exists, and which are expected to be re-sold shortly after purchase, are one example of excluded items.

Crude Oil

At December 31, 2009, Suncor had purchase commitments relating to crude oil predominately for refinery supply. Crude oil commitments consisted of market price evergreen contracts for a total volume of 245,000 barrels per day of crude oil (2008 – 182,000 bbls/day), of which most have industry standard thirty-day cancellation clauses.

Natural Gas

At December 31, 2009, Suncor had purchase commitments relating to natural gas for physical trading. Natural gas commitments consist of fixed price contracts with a total volume of 7 million GJ (2008 – 8 million GJ) within a price range of Cdn $4.51 – $7.05 per GJ (2008 – $5.80-$9.47 per GJ) and having terms extending to October 2010 (2008 – December 2009), as well as market price contracts for a total volume of 60 million GJ (2008 – 17 million GJ) with terms extending to October 2015 (2008 – October 2009).

Refined Products

At December 31, 2009, Suncor's significant purchase commitments relating to finished products at its refineries consisted of market price contracts for a total volume of 5,429 millions of litres and having terms extending to 2012.

(b) Contingencies

The company is subject to various regulatory and statutory requirements relating to the protection of the environment. These requirements, in addition to contractual agreements and management decisions, result in the recognition of estimated asset retirement obligations. Estimates of asset retirement obligation costs can change significantly based on such factors as operating experience and changes in legislation and regulations.

The company reduces exposure to some operational risks by maintaining a comprehensive insurance program at limits and deductible amounts that management believes to be acceptable.

The company carries property damage and business interruption insurance with varying coverage limits and deductible amounts based on the asset. As of December 31, 2009, Suncor's insurance program includes a coverage limit of up to US$1.35 billion for

oil sands risks, up to US$1.25 billion for offshore risks and up to US$420 million for refining risks. These limits are all net of deductible amounts or waiting periods and subject to certain price and volume caps. The company also has primary property insurance for US$250 million that covers all of Suncor's assets.

Suncor believes its liability, property and business interruption insurance is appropriate to its business, although such insurance will not provide coverage in all circumstances or fully protect against prolonged outages. In the future, the insurance program may change due to market conditions or other business considerations.

The company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and to be funded from the company's cash flow from operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, the impact may be material.

(c) Variable Interest Entities

CICA Accounting Guideline 15, *Consolidation of Variable Interest Entities* (VIEs), provides criteria for the identification of VIEs and further criteria for determining what entity, if any, should consolidate them. Entities in which equity investors do not have the characteristic of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinate financial support are subject to consolidation by a company if that company is deemed the primary beneficiary. The primary beneficiary is the party that is subject to a majority of the risk of loss from the VIEs activities, or is entitled to receive a majority of the VIE's residual returns, or both. The company has determined that certain retail licensee and wholesale marketer agreements would constitute VIEs, even though the company has no ownership in these entities. The company, however, is not the primary beneficiary and, therefore, consolidation is not required. In certain of the retail licensee arrangements, the company has provided loan guarantees. Management is of the opinion that the company's maximum exposure to loss from these arrangements would not be significant.

(d) Guarantees and Off-Balance Sheet Arrangements

At December 31, 2009, the company had various indemnification agreements with third parties as described below.

The company has agreed to indemnify holders of all notes and debentures and the company's credit facility lenders (see note 17) for added costs relating to taxes, assessments or other government charges or conditions, including any required withholding amounts. Similar indemnity terms apply to certain facility and equipment leases.

There is no limit to the maximum amount payable under the indemnification agreements described above. The company is unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, the company has the option to redeem or terminate these contracts if additional costs are incurred.

20. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

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

21. SUPPLEMENTAL INFORMATION

($ millions)	**2009**	2008	2007
Geographic areas			
Revenues			
Canada	**20 184**	23 742	13 262
U.S.	**4 010**	4 794	3 943
Other	**1 286**	101	109
	25 480	28 637	17 314
Total assets			
Canada	**54 259**	29 178	21 615
U.S.	**5 239**	2 840	2 556
Other	**10 248**	510	338
	69 746	32 528	24 509
Exploration expenses			
Geological and geophysical	**85**	29	28
Dry hole costs	**173**	61	67
Other	**10**	—	—
Total	**268**	90	95
Allowance for doubtful accounts	**16**	4	3

22. SUBSEQUENT EVENTS

A fire on February 9, 2010 damaged portions of one of the company's oil sands upgraders. An assessment of the damage and expected schedule for repairs has been completed, and repairs are currently underway. The company expects the damaged upgrader to return to production in early April 2010. Based on the damage assessment and repair schedule, and applicable waiting periods and deductibles, the company does not expect insurance to play a significant role in mitigating losses from this incident.

On February 9, 2010, Suncor entered into an agreement to sell certain natural gas properties located in northeast British Columbia for proceeds of $390 million. The sale is expected to close in March 2010.

On February 25, 2010, Suncor entered into an agreement to sell its assets in Trinidad and Tobago for proceeds of $396 million (US$380 million). The sale is expected to close in March 2010.

23. DIFFERENCES BETWEEN CANADIAN AND U.S. GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The consolidated financial statements have been prepared in accordance with Canadian GAAP. The application of United States GAAP (U.S. GAAP) would have the following effects on net earnings and comprehensive income as reported:

($ millions)	Notes	**2009**	2008	2007
Net earnings as reported, Canadian GAAP		**1 146**	2 137	2 983
Adjustments				
Transaction costs and provisions	(a)	**(302)**	—	—
Stock-based compensation expense	(b)	**41**	(7)	15
Energy supply and trading activities (inventory valuation)	(e)	**(47)**	—	—
Income tax expense	(a,b,e)	**80**	1	(6)
Net earnings, U.S. GAAP		**918**	2 131	2 992
Pension and post-retirement obligation, net of income taxes of $22 (2008 – $20; 2007 – $8)	(c)	**43**	43	17
Other comprehensive income (loss) items		**(330)**	350	(190)
Comprehensive income, U.S. GAAP		**631**	2 524	2 819

Per common share (dollars)	**2009**	2008	2007
Net earnings per share, U.S. GAAP			
Basic	**0.77**	2.29	3.24
Diluted	**0.76**	2.26	3.18

The application of U.S. GAAP would have the following effects on the consolidated balance sheets as reported:

		December 31, 2009		December 31, 2008	
	Notes	As Reported	U.S. GAAP	As Reported	U.S. GAAP
Current assets	(a,e)	**8 331**	**8 318**	3 237	3 237
Property, plant and equipment, net		**57 485**	**57 485**	28 882	28 882
Other assets	(d)	**536**	**599**	388	460
Goodwill	(a)	**3 201**	**5 762**	21	21
Future income taxes		**193**	**210**	—	—
Total assets		**69 746**	**72 374**	32 528	32 600
Current liabilities	(a,b)	**7 848**	**7 881**	3 538	3 538
Long-term borrowings	(d)	**13 855**	**13 918**	7 866	7 938
Accrued liabilities and other	(b,c)	**5 062**	**5 119**	1 986	2 094
Future income taxes	(a,b,c)	**8 870**	**8 840**	4 615	4 579
Share capital	(b)	**20 053**	**22 908**	1 113	1 201
Contributed surplus	(b)	**526**	**546**	288	313
Retained earnings	(a,b,e)	**13 765**	**13 431**	13 025	12 919
Accumulated other comprehensive income (loss)	(c)	**(233)**	**(269)**	97	18
Total liabilities and shareholders' equity		**69 746**	**72 374**	32 528	32 600

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

(a) Business Combination with Petro-Canada

Under U.S. GAAP, the total purchase price for the acquisition was $22,225 million. U.S. GAAP requires the 621.1 million Suncor shares offered as consideration to complete the merger to be valued at $34.84 per share, which was the Suncor Share price as at the transaction close date of August 1, 2009. Under Canadian GAAP the share price is that value as at the merger announcement date. In addition, transaction costs of $124 million (net of income taxes of $43 million) are not permitted to be included in consideration under U.S. GAAP, and are expensed instead.

Under Canadian GAAP, the transaction costs were netted against cash acquired in the business combination and presented as part of cash flow from investing activities in the Consolidated Statements of Cash Flows. Under U.S. GAAP the $124 million of transaction costs would be included in net earnings and thus be presented as a reduction in cash flow from operating activities.

The fair value of current liabilities assumed by Suncor in the business combination under Canadian GAAP includes $160 million (net of income taxes of $56 million) for provisions for severance and other costs associated with exiting certain activities of Petro-Canada that cannot be recognized at the time of the merger under U.S. GAAP and instead must be expensed as incurred. As at December 31, 2009, $99 million (net of income taxes of $36 million) of amounts related to these provisions had been incurred, for which $12 million (net of income taxes of $4 million) remains in current liabilities under U.S. GAAP.

As per note (b), under U.S. GAAP stock-based compensation awards recognized as liabilities are measured using different methods than Canadian GAAP. At August 1, 2009, the value of CPAs, SARs, RSUs and PSUs calculated using methods prescribed by U.S. GAAP was $126 million (net of income taxes of $43 million) greater than the value calculated using methods prescribed under Canadian GAAP.

As a result of these differences in accounting for this business combination, the resulting value for goodwill under U.S. GAAP is $5,762 million, of which $5,474 million would be allocated to the Oil Sands segment and the remaining $288 million would be allocated to the Refining and Marketing segment.

(b) Stock-Based Compensation

Under Canadian GAAP, the company's stock options with a cash payment alternatives (CPAs), stock appreciation rights (SARs), performance share units (PSUs) and restricted share units (RSUs) are measured using an intrinsic approach, which is a fair-value technique not permitted under U.S. GAAP. For U.S. GAAP, our CPAs and SARs have been measured at fair value using the Black-Scholes option-pricing model, while our PSUs and RSUs have been measured using a Monte Carlo Simulation approach to

determine fair value. The impact on net earnings for the year ended December 31, 2009 is a recovery of previously recognized stock-based compensation expense of $31 million, net of income taxes of $10 million (2008 — expense of $2 million, net of income taxes $1 million; 2007 — recovery of $17 million, net of income taxes of $6 million).

Under Canadian GAAP, compensation expense related to common share options granted prior to January 1, 2003 ("pre-2003 options") is not recognized in the Consolidated Statements of Earnings. U.S. GAAP requires the recognition of expense related to the company's pre-2003 options. There was no additional compensation expense to recognize in 2009, as the remaining expense for pre-2003 options was recognized in 2008 (2008 — $4 million, 2007 — $8 million). There was no impact on income taxes.

(c) Accounting for Defined Benefit Pension and Other Post-Retirement Plans

U.S. GAAP requires the company recognize the over funded or under funded status of a defined benefit post-retirement plan as an asset or liability on the balance sheet, with changes to funded status in the year recorded through comprehensive income, net of income taxes. Canadian GAAP currently does not require the company to recognize the funded status of these plans in the Consolidated Balance Sheet. In 2009, other comprehensive income under U.S. GAAP would increase by $43 million, net of income taxes of $22 million (2008 – $43 million, net of income taxes of $20 million).

(d) Deferred Financing Costs

Effective January 1, 2007, under Canadian GAAP, deferred financing costs on long-term debt are included in the carrying value of the related debt. Under U.S. GAAP, these costs are recorded as a deferred charge. As a result, $63 million would have been reclassified from long-term debt to deferred charges and other at December 31, 2009 (December 31, 2008 – $72 million).

(e) Inventory

U.S. GAAP requires inventory to be measured at the lower of cost or net realizable value and does not permit the measurement of held for trading inventories at fair value less costs to sell. As a result, the value of energy trading inventories at December 31, 2009 is lower by $47 million, with the difference in valuation charged to energy supply and trading activities revenue ($32 million, net of income taxes of $15 million).

(f) Cash Flow Information

Other than described in note (a), the application of U.S. GAAP would not have a material effect on cash flow from total operating, investing, or financing activities on the Consolidated Statement of Cash Flows.

Recently Adopted Accounting Standards

Codification

Effective September 15, 2009 the U.S. Financial Accounting Standards Board (FASB) introduced the FASB Accounting Standards Codification (Codification) as the source of authoritative U.S. GAAP for financial statements issued for annual periods ending after the effective date. The Codification did not affect the application of U.S. GAAP to the company's U.S. GAAP financial statements.

Business Combinations

In December 2007, the FASB amended Topic 805 "Business Combinations" and Topic 810 "Consolidations" which are effective for all business combinations occurring on or after January 1, 2009. These standards require the identifiable assets acquired and liabilities assumed in a business combination to be recorded at fair value and most of the related acquisition and restructuring costs to be expensed. The impact to Suncor has been quantified in section (a) above.

Oil and Gas Reporting Requirements

In January 2010, the FASB amended Topic 932 "Extractive Industries Oil and Gas" to align the oil and gas reserve estimation and disclosure requirements of Topic 932 with the changes implemented by the Securities and Exchange Commission Final Rule, Modernization of Oil and Gas Reporting Requirements.

The amendments expand the definition of an oil and gas producing activity to include resources extracted through mining activities, coal beds and shale. The new rules also permit the use of new technologies to determine proved reserves, if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. The new rules will also require companies to report their oil and gas reserves based on annual average prices determined by the prices in effect on the first day of each month, rather than year-end prices. The amendments are effective for December 31, 2009.

Recently Issued Accounting Standards

Consolidations

In June 2009, the FASB issued amendments to Topic 810 "Consolidations" to improve financial reporting for enterprises involved with variable interest entities (VIEs). The amendments change how a company determines when these entities should be consolidated, replacing the quantitative-based risks and rewards calculation with an approach that is primarily qualitative. The amendments are effective for January 1, 2010. The company does not anticipate changes to its reporting for VIEs as a result of these amendments.

QUARTERLY SUMMARY (unaudited)

FINANCIAL DATA [1]

($ millions, except per share amounts)	For the Quarter Ended Mar 31 2009	June 30 2009	Sept 30 2009	Dec 31 2009	Total Year 2009	For the Quarter Ended Mar 31 2008	June 30 2008	Sept 30 2008	Dec 31 2008	Total Year 2008
Revenues (net of royalties)	**4 633**	**4 768**	**8 443**	**7 636**	**25 480**	5 538	7 640	8 507	6 952	28 637
Net earnings (loss)										
Oil Sands	**(110)**	**(307)**	**738**	**236**	**557**	695	751	854	575	2 875
Natural Gas	**(10)**	**(28)**	**(111)**	**(50)**	**(199)**	19	52	18	—	89
East Coast Canada	**—**	**—**	**39**	**73**	**112**	—	—	—	—	—
International	**—**	**—**	**32**	**133**	**165**	—	—	—	—	—
Refining and Marketing	**118**	**106**	**51**	**158**	**433**	78	102	(11)	(174)	(5)
Corporate, Energy Trading and Eliminations	**(187)**	**178**	**180**	**(93)**	**78**	(84)	(76)	(46)	(616)	(822)
	(189)	**(51)**	**929**	**457**	**1 146**	708	829	815	(215)	2 137
Per common share										
Net earnings (loss) attributable to common shareholders										
– basic	**(0.20)**	**(0.06)**	**0.69**	**0.29**	**0.96**	0.77	0.89	0.87	(0.24)	2.29
– diluted	**(0.20)**	**(0.06)**	**0.68**	**0.29**	**0.95**	0.75	0.87	0.86	(0.24)	2.26
Cash dividends	**0.05**	**0.05**	**0.10**	**0.10**	**0.30**	0.05	0.05	0.05	0.05	0.20
Cash flow from (used in) operations										
Oil Sands	**480**	**174**	**242**	**355**	**1 251**	924	1 232	1 030	321	3 507
Natural Gas	**53**	**42**	**74**	**160**	**329**	84	122	98	63	367
East Coast Canada	**—**	**—**	**130**	**205**	**335**	—	—	—	—	—
International	**—**	**—**	**163**	**453**	**616**	—	—	—	—	—
Refining and Marketing	**222**	**198**	**275**	**268**	**963**	173	237	19	(181)	248
Corporate, Energy Trading and Eliminations	**46**	**(119)**	**(310)**	**(312)**	**(695)**	(31)	(61)	(1)	28	(65)
	801	**295**	**574**	**1 129**	**2 799**	1 150	1 530	1 146	231	4 057

(1) The financial data includes the results of post-merger Suncor from August 1, 2009. As such, the amounts reflect results of the post-merger Suncor from August 1, 2009 together with results of legacy Suncor only from January 1, 2009 through July 31, 2009. The comparative figures reflect solely the 2008 results of legacy Suncor.

QUARTERLY SUMMARY (unaudited) (continued)

OPERATING DATA

	For the Quarter Ended Mar 31 2009	June 30 2009	Sept 30 2009	Dec 31 2009	Total Year 2009	For the Quarter Ended Mar 31 2008	June 30 2008	Sept 30 2008	Dec 31 2008	Total Year 2008
OIL SANDS										
Production[a]										
Total production (excluding Syncrude)	**278.0**	**301.0**	**305.3**	**278.9**	**290.6**	248.0	174.6	245.6	243.8	228.0
Firebag[b]	**42.4**	**48.3**	**54.3**	**51.1**	**49.1**	34.6	34.7	40.4	39.7	37.4
Mackay River[b]	**—**	**—**	**26.5*** **	**31.7**	**29.7*** **	—	—	—	—	—
Syncrude	**—**	**—**	**37.4*** **	**39.3**	**38.5*** **	—	—	—	—	—
Sales[a]										
Light sweet crude oil	**108.8**	**99.4**	**89.6**	**100.8**	**99.6**	96.2	68.2	48.1	95.7	77.0
Diesel	**22.8**	**25.3**	**36.9**	**31.4**	**29.1**	28.0	21.2	10.9	19.1	19.8
Light sour crude oil	**102.7**	**150.5**	**146.8**	**142.4**	**135.7**	120.8	91.8	157.4	144.2	128.7
Bitumen	**9.1**	**10.5**	**14.3**	**13.0**	**11.8**	0.1	0.3	2.6	3.1	1.5
Total sales	**243.4**	**285.7**	**287.6**	**287.6**	**276.2**	245.1	181.5	219.0	262.1	227.0
Average sales price[1], [c]										
Light sweet crude oil*	**54.64**	**65.83**	**71.99**	**77.71**	**67.26**	100.93	122.12	125.70	63.69	98.66
Other (diesel, light sour crude oil and bitumen)*	**48.80**	**62.71**	**67.51**	**72.93**	**64.18**	93.09	120.52	114.74	59.77	95.14
Total*	**52.78**	**63.79**	**68.91**	**74.61**	**65.29**	96.22	122.39	117.14	61.20	96.33
Total	**59.14**	**59.00**	**61.70**	**64.81**	**61.26**	96.16	121.12	116.32	61.53	95.96
Syncrude average sales price[1], [c]	**—**	**—**	**75.17**	**78.81**	**77.36**	—	—	—	—	—
Cash operating costs and Total operating costs – Total Operations (excluding Syncrude)[d]										
Cash costs	**30.65**	**29.65**	**30.65**	**35.10**	**31.50**	25.10	40.10	27.80	35.35	31.45
Natural gas	**3.00**	**1.65**	**1.55**	**3.40**	**2.40**	5.00	8.75	4.30	4.05	5.25
Imported bitumen	**0.05**	**—**	**0.05**	**0.20**	**0.05**	1.45	2.00	1.90	1.90	1.80
Cash operating costs[2]	**33.70**	**31.30**	**32.25**	**38.70**	**33.95**	31.55	50.85	34.00	41.30	38.50
Project start-up costs	**0.65**	**0.35**	**0.45**	**0.50**	**0.45**	0.30	0.90	0.35	0.30	0.40
Total cash operating costs[3]	**34.35**	**31.65**	**32.70**	**39.20**	**34.40**	31.85	51.75	34.35	41.60	38.90
Depreciation, depletion and amortization	**7.30**	**7.20**	**7.60**	**10.00**	**8.00**	5.75	8.30	6.70	7.50	6.95
Total operating costs[4]	**41.65**	**38.85**	**40.30**	**49.20**	**42.40**	37.60	60.05	41.05	49.10	45.85
Cash operating costs and Total operating costs – Syncrude[d]****										
Cash costs	**—**	**—**	**29.50**	**29.65**	**29.60**	—	—	—	—	—
Natural gas	**—**	**—**	**2.10**	**3.45**	**2.90**	—	—	—	—	—
Cash operating costs[5]	**—**	**—**	**31.60**	**33.10**	**32.50**	—	—	—	—	—
Project start-up costs	**—**	**—**	**—**	**—**	**—**	—	—	—	—	—
Total cash operating costs[6]	**—**	**—**	**31.60**	**33.10**	**32.50**	—	—	—	—	—
Depreciation, depletion and amortization	**—**	**—**	**12.70**	**11.80**	**12.15**	—	—	—	—	—
Total operating costs[7]	**—**	**—**	**44.30**	**44.90**	**44.65**	—	—	—	—	—
Cash operating costs and Total operating costs – In-situ Bitumen Production Only[c]										
Cash costs	**10.50**	**11.15**	**10.25**	**11.35**	**10.90**	14.60	10.10	10.75	16.55	13.00
Natural gas	**7.90**	**5.25**	**4.30**	**6.05**	**5.70**	14.10	14.55	11.30	9.65	12.30
Cash operating costs[5]	**18.40**	**16.40**	**14.55**	**17.40**	**16.60**	28.70	24.65	22.05	26.20	25.30
In-situ start-up costs	**3.35**	**1.50**	**0.65**	**1.25**	**1.30**	0.35	1.65	0.80	—	0.65
Total cash operating costs[6]	**21.75**	**17.90**	**15.20**	**18.65**	**17.90**	29.05	26.30	22.85	26.20	25.95
Depreciation, depletion and amortization	**7.10**	**6.00**	**5.95**	**6.65**	**6.35**	6.75	6.70	5.40	6.55	6.35
Total operating costs[7]	**28.85**	**23.90**	**21.15**	**25.30**	**24.25**	35.80	33.00	28.25	32.75	32.30

Footnotes and definitions, see page 113.

QUARTERLY SUMMARY (unaudited) (continued)

OPERATING DATA (continued)

	For the Quarter Ended				Total Year	For the Quarter Ended				Total Year
	Mar 31 2009	**June 30 2009**	**Sept 30 2009**	**Dec 31 2009**	**2009**	Mar 31 2008	June 30 2008	Sept 30 2008	Dec 31 2008	2008
NATURAL GAS										
Gross production										
Natural gas[e]										
Western Canada	**200**	**192**	**477**	**620**	**374**	209	205	197	195	202
U.S. Rockies	**—**	**—**	**40**	**54**	**24**	—	—	—	—	—
Natural gas liquids and crude oil[a]										
Western Canada	**3.1**	**3.2**	**8.3**	**10.8**	**6.4**	3.3	3.4	2.6	3.1	3.1
U.S. Rockies	**—**	**—**	**2.4**	**4.2**	**1.7**	—	—	—	—	—
Total gross production[f]										
Western Canada	**219**	**211**	**527**	**685**	**412**	229	226	213	213	220
U.S. Rockies	**—**	**—**	**54**	**79**	**34**	—	—	—	—	—
Average sales price[1]										
Natural gas[g]										
Western Canada	**5.63**	**3.56**	**2.79**	**3.99**	**3.70**	7.30	9.62	9.10	6.90	8.23
U.S. Rockies	**—**	**—**	**3.01**	**4.62**	**3.93**	—	—	—	—	—
Natural gas[g]*										
Western Canada	**5.61**	**3.52**	**2.77**	**3.99**	**3.68**	7.31	9.68	9.14	6.84	8.25
U.S. Rockies	**—**	**—**	**3.01**	**4.62**	**3.93**	—	—	—	—	—
Natural gas liquids and crude oil[c]										
Western Canada	**39.03**	**41.39**	**53.28**	**60.06**	**52.97**	64.14	86.14	96.88	39.31	70.89
U.S. Rockies	**—**	**—**	**67.08**	**74.19**	**71.62**	—	—	—	—	—
EAST COAST CANADA* **										
Production[a]										
Terra Nova	**—**	**—**	**16.0**	**24.0**	**20.8**	—	—	—	—	—
Hibernia	**—**	**—**	**28.5**	**26.3**	**27.2**	—	—	—	—	—
White Rose	**—**	**—**	**5.1**	**13.3**	**10.0**	—	—	—	—	—
Total production	**—**	**—**	**49.6**	**63.6**	**58.0**	—	—	—	—	—
Average sales price[1]	**—**	**—**	**75.22**	**77.71**	**76.86**	—	—	—	—	—
INTERNATIONAL* **										
Production[h]										
North Sea										
Buzzard	**—**	**—**	**29.4**	**59.9**	**47.8**	—	—	—	—	—
Other U.K.	**—**	**—**	**11.4**	**18.2**	**15.5**	—	—	—	—	—
The Netherlands sector of the North Sea	**—**	**—**	**13.8**	**12.9**	**13.2**	—	—	—	—	—
Total North Sea	**—**	**—**	**54.6**	**91.0**	**76.5**	—	—	—	—	—
Other International										
Libya	**—**	**—**	**42.7**	**26.0**	**32.6**	—	—	—	—	—
Trinidad & Tobago	**—**	**—**	**11.3**	**12.0**	**11.7**	—	—	—	—	—
Total Other International	**—**	**—**	**54.0**	**38.0**	**44.3**	—	—	—	—	—
Total production	**—**	**—**	**108.6**	**129.0**	**120.8**	—	—	—	—	—
Average sales price[1] **– North Sea**[i]	**—**	**—**	**68.67**	**71.46**	**71.63**	—	—	—	—	—
Average sales price[1] **– Other International**[i]	**—**	**—**	**62.40**	**59.04**	**61.25**	—	—	—	—	—

Footnotes and definitions, see page 113.

OPERATING DATA (continued)

	For the Quarter Ended				Total Year	For the Quarter Ended				Total Year
	Mar 31 2009	**June 30 2009**	**Sept 30 2009**	**Dec 31 2009**	**2009**	Mar 31 2008	June 30 2008	Sept 30 2008	Dec 31 2008	2008
REFINING AND MARKETING										
Eastern North America										
Refined product sales [j]										
Transportation fuels										
Gasoline										
– retail	**3.8**	**4.0**	**12.5**	**16.5**	**9.3**	3.9	3.9	3.8	3.9	3.9
– other	**4.4**	**4.7**	**5.8**	**6.5**	**5.3**	3.8	4.0	4.3	5.0	4.0
Distillate	**5.1**	**5.4**	**10.3**	**13.9**	**8.8**	4.8	5.6	5.2	5.4	5.2
Total transportation fuel sales	**13.3**	**14.1**	**28.6**	**36.9**	**23.4**	12.5	13.5	13.3	14.3	13.1
Petrochemicals	**1.0**	**1.0**	**1.7**	**1.2**	**0.8**	0.6	0.9	1.0	1.0	0.8
Asphalt	**0.8**	**0.7**	**2.4**	**2.0**	**1.5**	0.6	0.7	0.6	0.5	0.6
Other	**0.5**	**1.0**	**3.0**	**1.9**	**2.0**	0.8	1.1	1.2	0.5	1.0
Total refined product sales	**15.6**	**16.8**	**35.7**	**42.0**	**27.7**	14.5	16.2	16.1	16.3	15.5
Crude oil supply and refining										
Processed at refineries [j]	**11.3**	**11.8**	**25.5**	**28.3**	**29.6**	9.9	11.5	11.6	11.2	11.0
Utilization of refining capacity (%)	**84**	**87**	**94**	**83**	**87**	89	103	104	101	99
Western North America										
Refined product sales [j]										
Transportation fuels										
Gasoline										
– retail	**0.7**	**0.6**	**3.8**	**5.0**	**2.6**	0.7	0.6	0.7	0.7	0.7
– other	**7.5**	**8.3**	**12.3**	**13.4**	**10.4**	7.0	7.8	7.2	7.1	7.3
Distillate	**5.4**	**5.0**	**11.8**	**15.6**	**9.5**	5.6	5.9	5.4	5.5	5.6
Total transportation fuel sales	**13.6**	**13.9**	**27.9**	**34.0**	**22.5**	13.3	14.3	13.3	13.3	13.6
Asphalt	**1.2**	**1.4**	**1.7**	**0.9**	**1.3**	1.6	1.0	1.3	1.0	1.2
Other	**1.0**	**1.8**	**4.6**	**6.0**	**3.4**	1.1	1.6	1.3	0.9	1.2
Total refined product sales	**15.8**	**17.1**	**34.2**	**40.9**	**27.2**	16.0	16.9	15.9	15.2	16.0
Crude oil supply and refining										
Processed at refineries [j]	**14.2**	**15.6**	**27.8**	**33.4**	**33.6**	13.1	14.5	13.5	13.6	13.7
Utilization of refining capacity (%)	**96**	**106**	**100**	**96**	**97**	92	102	95	95	96

Footnotes and definitions, see page 113.

OPERATING DATA (continued)

	For the Quarter Ended				Total Year	For the Quarter Ended				Total Year
	Mar 31 2009	**June 30 2009**	**Sept 30 2009**	**Dec 31 2009**	**2009**	Mar 31 2008	June 30 2008	Sept 30 2008	Dec 31 2008	2008
NETBACKS										
Natural Gas[g]										
Western Canada										
Average price realized[8]	**5.77**	**3.88**	**3.76**	**5.05**	**4.58**	8.23	11.20	10.98	6.99	9.35
Royalties	**(1.14)**	**0.33**	**(0.24)**	**(0.72)**	**(0.49)**	(1.84)	(2.52)	(2.70)	(1.60)	(2.17)
Operating costs	**(1.65)**	**(1.71)**	**(1.90)**	**(1.77)**	**(1.79)**	(1.41)	(1.66)	(1.87)	(1.46)	(1.60)
Operating netback	**2.98**	**2.50**	**1.62**	**2.56**	**2.30**	4.98	7.02	6.41	3.93	5.58
Depreciation, depletion and amortization	**(2.97)**	**(2.92)**	**(2.73)**	**(2.62)**	**(2.74)**	(2.85)	(2.68)	(3.08)	(2.98)	(2.89)
Administrative expenses and other	**(0.78)**	**(1.63)**	**(1.60)**	**(1.09)**	**(1.29)**	(0.88)	(0.92)	(1.95)	(1.23)	(1.23)
Earnings before income taxes	**(0.77)**	**(2.05)**	**(2.71)**	**(1.15)**	**(1.73)**	1.25	3.42	1.38	(0.28)	1.46
U.S. Rockies										
Average price realized[8]	**—**	**—**	**5.20**	**7.15**	**6.35**	—	—	—	—	—
Royalties	**—**	**—**	**(0.82)**	**(1.13)**	**(1.01)**	—	—	—	—	—
Operating costs	**—**	**—**	**(1.79)**	**(1.83)**	**(1.82)**	—	—	—	—	—
Operating netback	**—**	**—**	**2.59**	**4.19**	**3.52**	—	—	—	—	—
Depreciation, depletion and amortization	**—**	**—**	**(3.20)**	**(3.44)**	**(3.35)**	—	—	—	—	—
Administrative expenses and other	**—**	**—**	**(0.47)**	**(0.66)**	**(0.58)**	—	—	—	—	—
Earnings before income taxes	**—**	**—**	**(1.08)**	**0.09**	**(0.41)**	—	—	—	—	—
Total Natural Gas										
Average price realized[8]	**5.77**	**3.88**	**3.89**	**5.26**	**4.71**	8.23	11.20	10.98	6.99	9.35
Royalties	**(1.14)**	**0.33**	**(0.29)**	**(0.76)**	**(0.53)**	(1.84)	(2.52)	(2.70)	(1.60)	(2.17)
Operating costs	**(1.65)**	**(1.71)**	**(1.89)**	**(1.78)**	**(1.79)**	(1.41)	(1.66)	(1.87)	(1.46)	(1.60)
Operating netback	**2.98**	**2.50**	**1.71**	**2.72**	**2.39**	4.98	7.02	6.41	3.93	5.58
Depreciation, depletion and amortization	**(2.97)**	**(2.92)**	**(2.78)**	**(2.70)**	**(2.79)**	(2.85)	(2.68)	(3.08)	(2.98)	(2.89)
Administrative expenses and other	**(0.78)**	**(1.63)**	**(1.49)**	**(1.05)**	**(1.23)**	(0.88)	(0.92)	(1.95)	(1.23)	(1.23)
Earnings before income taxes	**(0.77)**	**(2.05)**	**(2.56)**	**(1.03)**	**(1.63)**	1.25	3.42	1.38	(0.28)	1.46

Footnotes and definitions, see page 113.

OPERATING DATA (continued)

	For the Quarter Ended Mar 31 2009	June 30 2009	Sept 30 2009	Dec 31 2009	Total Year 2009	For the Quarter Ended Mar 31 2008	June 30 2008	Sept 30 2008	Dec 31 2008	Total Year 2008
NETBACKS (continued)										
East Coast Canada[c]										
Average price realized[8]	—	—	77.85	79.69	79.07	—	—	—	—	—
Royalties	—	—	(21.02)	(25.26)	(23.82)	—	—	—	—	—
Operating costs	—	—	(13.36)	(7.89)	(9.76)	—	—	—	—	—
Operating netback	—	—	43.47	46.54	45.49	—	—	—	—	—
Depreciation, depletion and amortization	—	—	(17.48)	(26.56)	(23.47)	—	—	—	—	—
Administrative expenses and other	—	—	(0.52)	(1.33)	(1.05)	—	—	—	—	—
Earnings before income taxes	—	—	25.47	18.65	20.97	—	—	—	—	—
International										
North Sea[c]										
Average price realized[8]	—	—	72.06	71.46	71.63	—	—	—	—	—
Operating costs	—	—	(14.04)	(8.08)	(9.78)	—	—	—	—	—
Operating netback	—	—	58.02	63.38	61.85	—	—	—	—	—
Depreciation, depletion and amortization	—	—	(24.54)	(34.63)	(31.76)	—	—	—	—	—
Administrative expenses and other	—	—	(7.61)	(4.62)	(5.48)	—	—	—	—	—
Earnings before income taxes	—	—	25.87	24.13	24.61	—	—	—	—	—
Other International										
North Africa/Near East[c]										
Average price realized[8]	—	—	76.02	79.97	78.19	—	—	—	—	—
Royalties	—	—	(46.46)	(32.12)	(39.88)	—	—	—	—	—
Operating costs	—	—	(2.21)	(6.03)	(4.05)	—	—	—	—	—
Operating netback	—	—	27.35	41.82	34.26	—	—	—	—	—
Depreciation, depletion and amortization	—	—	(2.31)	(7.70)	(4.89)	—	—	—	—	—
Administrative expenses and other	—	—	(5.21)	(10.15)	(7.57)	—	—	—	—	—
Earnings before income taxes	—	—	19.83	23.97	21.80	—	—	—	—	—
Other International										
Northern Latin America[g]										
Average price realized[8]	—	—	2.09	2.58	2.42	—	—	—	—	—
Royalties	—	—	(1.58)	(0.10)	(0.69)	—	—	—	—	—
Operating costs	—	—	(0.46)	(0.13)	(0.26)	—	—	—	—	—
Operating netback	—	—	0.05	2.35	1.47	—	—	—	—	—
Depreciation, depletion and amortization	—	—	(0.79)	(1.84)	(1.44)	—	—	—	—	—
Administrative expenses and other	—	—	0.12	0.04	0.08	—	—	—	—	—
Earnings before income taxes	—	—	(0.62)	0.55	0.11	—	—	—	—	—
Total International[i]										
Average price realized[8]	—	—	67.42	67.96	67.86	—	—	—	—	—
Royalties	—	—	(19.25)	(6.52)	(11.17)	—	—	—	—	—
Operating costs	—	—	(8.22)	(6.99)	(7.44)	—	—	—	—	—
Operating netback	—	—	39.95	54.45	49.25	—	—	—	—	—
Depreciation, depletion and amortization	—	—	(13.74)	(27.02)	(22.27)	—	—	—	—	—
Administrative expenses and other	—	—	(5.79)	(5.29)	(5.46)	—	—	—	—	—
Earnings before income taxes	—	—	20.42	22.14	21.52	—	—	—	—	—

Footnotes and definitions, see page 113.

FIVE-YEAR FINANCIAL SUMMARY (unaudited)

($ millions)	**2009**	2008	2007	2006	2005
Revenues (net of royalties)					
Oil Sands	**6 539**	8 639	6 175	6 457	3 559
Natural Gas	**681**	579	427	451	530
East Coast Canada	**441**	—	—	—	—
International	**1 183**	—	—	—	—
Refining and Marketing	**12 013**	9 419	8 391	7 209	6 351
Corporate, Energy Trading and Eliminations	**4 623**	10 000	2 321	859	328
	25 480	28 637	17 314	14 976	10 768
Net earnings (loss)					
Oil Sands	**557**	2 875	2 474	2 775	986
Natural Gas	**(199)**	89	25	106	155
East Coast Canada	**112**	—	—	—	—
International	**165**	—	—	—	—
Refining and Marketing	**433**	(5)	442	224	228
Corporate, Energy Trading and Eliminations	**78**	(822)	42	(136)	(115)
	1 146	2 137	2 983	2 969	1 254
Cash flow from (used in) operations					
Oil Sands	**1 251**	3 507	3 165	3 902	1 961
Natural Gas	**329**	367	251	279	412
East Coast Canada	**335**	—	—	—	—
International	**616**	—	—	—	—
Refining and Marketing	**963**	248	711	423	449
Corporate, Energy Trading and Eliminations	**(695)**	(65)	(90)	(58)	(193)
	2 799	4 057	4 037	4 546	2 629
Capital and exploration expenditures					
Oil Sands	**2 807**	7 391	4 566	2 463	2 013
Natural Gas	**320**	342	537	458	365
East Coast Canada	**123**	—	—	—	—
International	**543**	—	—	—	—
Refining and Marketing	**409**	226	449	745	789
Corporate, Energy Trading and Eliminations	**44**	28	77	27	63
	4 246	7 987	5 629	3 693	3 230
Total assets	**69 476**	32 528	24 509	18 959	15 335
Ending capital employed[(A)]					
Short-term and long-term debt, less cash and cash equivalents	**13 377**	7 226	3 248	1 849	2 868
Shareholders' equity	**34 111**	14 523	11 896	9 084	6 130
	47 488	21 749	15 144	10 933	8 998
Less capitalized costs related to major projects in progress	**(13 365)**	(6 583)	(4 148)	(2 649)	(2 938)
	34 123	15 166	10 996	8 284	6 060
Total Suncor employees (number at year-end)	**12 978**	6 798	6 465	5 766	5 152

Footnotes and definitions, see page 108.

FIVE-YEAR FINANCIAL SUMMARY (unaudited) (continued)

	2009	2008	2007	2006	2005
Dollars per common share					
Net earnings attributable to common shareholders	**0.96**	2.29	3.23	3.23	1.37
Cash dividends	**0.30**	0.20	0.19	0.15	0.12
Cash flow from operations	**2.34**	4.36	4.38	4.95	2.88
Ratios					
Return on capital employed (%) (B), (C)	**2.6**	22.5	29.3	40.0	21.2
Return on capital employed (%) (C), (D)	**1.8**	16.3	21.5	30.1	15.4
Return on shareholders' equity (%) (E)	**5.1**	16.2	28.4	39.0	22.7
Debt to debt plus shareholders' equity (%) (F)	**28.9**	35.2	24.3	20.7	33.1
Net debt to cash flow from operations (times) (G)	**4.8**	1.8	0.8	0.4	1.1
Interest coverage – cash flow basis (times) (H)	**7.2**	13.0	23.4	30.6	17.9
Interest coverage – net earnings basis (times) (I)	**3.0**	8.9	18.8	25.5	13.5

(A) Capital employed – the sum of shareholders' equity plus short-term debt and long-term debt less cash and cash equivalents, less capitalized costs related to major projects in progress (as applicable).

(B) Net earnings adjusted for after-tax financing expenses (income) for the twelve-month period ended; divided by average capital employed. Average capital employed is the sum of shareholders' equity and short-term debt plus long-term debt less cash and cash equivalents less capitalized costs related to major projects in progress (as applicable), on a weighted-average basis. Return on capital employed (ROCE) for Suncor operating segments is calculated in a manner consistent with consolidated ROCE. For a detailed annual reconciliation of this non-GAAP financial measure see page 53 of MD&A.

(C) The increase in capital employed as a result of the merger with Petro-Canada has caused our return on capital employed measure to decrease significantly, as the calculation only includes five months of results relating to legacy Petro-Canada operations.

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

(E) Net earnings as a percentage of average shareholders' equity. Average shareholders' equity is the sum of total shareholders' equity at the beginning and end of the year divided by two.

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

(G) Short-term debt plus long-term debt less cash and cash equivalents; divided by cash flow from operations for the year then ended. The increase in debt levels as a result of the merger with Petro-Canada has caused our net debt/cash flow from operations measure to increase significantly, as the calculation only includes five months of cash flow from operations relating to legacy Petro-Canada operations.

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

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

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited)

	2009	2008	2007	2006	2005
OIL SANDS					
Production [a]	**290.6**	228.0	235.6	260.0	171.3
Sales [a]					
Light sweet crude oil	**99.6**	77.0	101.7	110.5	73.3
Diesel	**29.1**	19.8	25.0	28.2	15.6
Light sour crude oil	**135.7**	128.7	102.3	118.2	59.8
Bitumen	**11.8**	1.5	5.7	6.2	16.6
	276.2	227.0	234.7	263.1	165.3
Average sales price [c]					
Light sweet crude oil*	**67.26**	98.66	78.03	71.98	49.93
Other (diesel, light sour crude oil and bitumen)*	**64.18**	95.14	70.86	65.17	56.90
Total*	**65.29**	96.33	74.07	68.03	62.68
Total	**61.26**	95.96	74.01	68.03	53.81
Cash operating costs – total operations (excluding Syncrude) [2],[d]	**33.95**	38.50	27.80	21.70	24.55
Total cash operating costs – total operations (excluding Syncrude) [3],[d]	**34.40**	38.90	28.75	22.10	24.65
Total operating costs – total operations (excluding Syncrude) [4],[d]	**42.40**	45.85	34.15	26.15	29.95
Cash operating costs – Syncrude [5],[d]****	**32.50**	—	—	—	—
Total cash operating costs – Syncrude [6],[d]****	**32.50**	—	—	—	—
Total operating costs – Syncrude [7],[d]****	**44.65**	—	—	—	—
Cash operating costs – In-situ bitumen production [5],[d]	**16.60**	25.30	20.75	17.30	22.20
Total cash operating costs – In-situ bitumen production [6],[d]	**17.90**	25.95	20.75	19.00	23.20
Total operating costs – In-situ bitumen production [7],[d]	**24.25**	32.30	26.95	24.55	28.10
Ending capital employed excluding major projects in progress [k]	**16 141**	9 352	6 605	5 039	4 468
Return on capital employed (%)	**4.2**	35.5	43.0	53.1	23.0
Return on capital employed (%)**	**2.5**	21.8	27.9	39.8	16.5

Footnotes and definitions, see page 113.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited) (continued)

	2009	2008	2007	2006	2005
NATURAL GAS					
Gross production					
Natural gas[e]					
Western Canada	**374**	202	196	191	190
U.S. Rockies	**24**	—	—	—	—
Natural gas liquids and crude oil[a]					
Western Canada	**6.4**	3.1	3.1	3.0	3.2
U.S. Rockies	**1.7**	—	—	—	—
Total[g]					
Western Canada	**412**	220	215	209	209
U.S. Rockies	**34**	—	—	—	—
Average sales price					
Natural gas[g]					
Western Canada	**3.70**	8.23	6.32	7.15	8.57
U.S. Rockies	**3.93**	—	—	—	—
Natural gas[g]*					
Western Canada	**3.68**	8.25	6.27	6.95	8.59
U.S. Rockies	**3.93**	—	—	—	—
Natural gas liquids and crude oil – conventional[c]					
Western Canada	**52.97**	70.89	56.64	51.93	54.24
U.S. Rockies	**71.62**	—	—	—	—
Ending capital employed[k]	**3 349**	1 152	1 153	857	562
Return on capital employed (%)	**(8.4)**	7.7	2.5	14.9	30.7

Footnotes and definitions, see page 113.

	2009	2008	2007	2006	2005
EAST COAST CANADA* **					
Production [a]					
Terra Nova	**20.8**	—	—	—	—
Hibernia	**27.2**	—	—	—	—
White Rose	**10.0**	—	—	—	—
Total production	**58.0**	—	—	—	—
Average sales price	**76.86**	—	—	—	—
Ending capital employed excluding major projects in progress [k]	**2 142**	—	—	—	—
Return on capital employed (%)	**10.7**	—	—	—	—
Return on capital employed (%)*	**6.5**	—	—	—	—
INTERNATIONAL* **					
Production [h]					
North Sea					
Buzzard	**47.8**	—	—	—	—
Other U.K.	**15.5**	—	—	—	—
The Netherlands sector of the North Sea	**13.2**	—	—	—	—
Total North Sea	**76.5**				
Other International					
Libya	**32.6**	—	—	—	—
Trinidad & Tobago	**11.7**	—	—	—	—
Total Other International	**44.3**	—	—	—	—
Total production	**120.8**	—	—	—	—
Average sales price – North Sea [c]	**71.63**	—	—	—	—
Average sales price – Other International [i]	**61.25**	—	—	—	—
Ending capital employed excluding major projects in progress [k]	**2 828**	—	—	—	—
Return on capital employed (%)	**11.5**	—	—	—	—
Return on capital employed (%)*	**7.5**	—	—	—	—

Footnotes and definitions, see page 113.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited) (continued)

	2009	2008	2007	2006	2005
REFINING AND MARKETING					
Eastern North America					
Refined product sales [j]					
Transportation fuels					
Gasoline					
Retail	**9.3**	3.9	4.5	4.6	4.5
Other	**5.3**	4.0	4.3	3.8	3.9
Distillate	**8.8**	5.2	5.4	3.9	4.2
Total transportation fuel sales	**23.4**	13.1	14.2	12.3	12.6
Petrochemicals	**0.8**	0.8	0.9	0.9	0.7
Asphalt	**1.5**	0.6	0.3	—	—
Other	**2.0**	1.0	2.2	1.9	1.9
Total refined product sales	**27.7**	15.5	17.6	15.1	15.2
Crude oil supply and refining					
Processed at refineries [j]	**29.6**	11.0	10.9	8.6	10.6
Utilization of refining capacity (%)	**87**	99	98	78	95
Western North America					
Refined product sales [j]					
Transportation fuels					
Gasoline					
Retail	**2.6**	0.7	0.7	0.7	0.7
Other	**10.4**	7.3	7.3	6.8	6.2
Distillate	**9.5**	5.6	5.2	4.6	4.1
Total transportation fuel sales	**22.5**	13.6	13.2	12.1	11.0
Asphalt	**1.3**	1.2	1.4	1.2	1.6
Other	**3.4**	1.2	1.3	1.1	1.1
Total refined product sales	**27.2**	16.0	15.9	14.4	13.7
Crude oil supply and refining					
Processed at refineries [j]	**33.6**	13.7	14.2	13.1	12.1
Utilization of refining capacity (%)	**97**	96	99	92	98
Ending capital employed excluding major projects in progress [k]	**8 304**	2 974	2 489	1 938	907
Return on capital employed (%)	**7.5**	1.8	20.0	19.3	27.5
Return on capital employed (%)**	**7.5**	1.8	17.4	12.2	17.6
Retail outlets (number at year-end)	**1 813**	427	419	417	417

Prior year capital employed measures have not been restated for the movement of energy trading activities to Corporate, Energy Trading and Eliminations.

Footnotes and definitions, see page 113.

Definitions

(1) Average sales price – This operating statistic is calculated before royalties (where applicable) and net of related transportation costs and excludes the realized impact of hedging activities unless stated.

(2) Cash operating costs – Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense and the cost of bitumen imported from third parties. Per barrel amounts are based on total production volumes. For a reconciliation of this non-GAAP financial measure see Management's Discussion and Analysis.

(3) Total cash operating costs – Include cash operating costs 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 as defined above and non-cash operating costs. Per barrel amounts are based on total production volumes.

(5) Cash operating costs – In-situ bitumen production – Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes) and accretion expense. Per barrel amounts are based on in-situ production volumes only.

(6) Total cash operating costs – In-situ bitumen production – Include cash operating costs – In-situ bitumen production as defined above and cash start-up operating costs. Per barrel amounts are based on in-situ production volumes only.

(7) Total operating costs – In-situ bitumen production – Include total cash operating costs – In-situ bitumen production as defined above and non-cash operating costs. Per barrel amounts are based on in-situ production volumes only.

(8) Average price realized – This operating statistic is calculated before transportation costs and royalties and excludes the impact of hedging activities.

Explanatory Notes

* Excludes the impact of realized hedging activities.

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

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

****Users are cautioned that the Syncrude 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 operations and capital costs among producers.

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

Metric conversion

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

SHARE TRADING INFORMATION (unaudited)

Common shares are listed on the Toronto Stock Exchange and New York Stock Exchange under the symbol SU.

	For the Quarter Ended				For the Quarter Ended			
	Mar 31 2009	**June 30 2009**	**Sept 30 2009**	**Dec 31 2009**	Mar 31 2008	June 30 2008	Sept 30 2008	Dec 31 2008
Share ownership								
Average number outstanding, weighted monthly (thousands)[a]	**936 550**	**937 005**	**1 349 263**	**1 559 512**	926 216	928 572	930 393	931 524
Share price (dollars)								
Toronto Stock Exchange								
High	**34.22**	**40.13**	**39.84**	**40.79**	56.14	73.10	62.37	43.78
Low	**21.15**	**27.44**	**29.90**	**34.66**	40.92	47.78	39.61	18.80
Close	**28.14**	**35.37**	**37.40**	**37.21**	49.61	59.20	44.00	23.72
New York Stock Exchange – US$								
High	**27.92**	**36.93**	**37.31**	**39.62**	56.73	74.28	61.99	41.12
Low	**16.95**	**21.61**	**25.51**	**31.84**	39.67	46.31	38.00	14.52
Close	**22.21**	**30.34**	**34.56**	**35.31**	52.61	68.56	51.64	19.02
Shares traded (thousands)								
Toronto Stock Exchange	**408 851**	**361 886**	**339 790**	**277 779**	219 094	226 392	266 381	396 680
New York Stock Exchange	**778 887**	**697 065**	**541 485**	**436 930**	342 938	371 303	458 534	720 851
Per common share information (dollars)								
Net earnings attributable to common shareholders	**(0.20)**	**(0.06)**	**0.69**	**0.29**	0.77	0.89	0.87	(0.24)
Cash dividends	**0.05**	**0.05**	**0.10**	**0.10**	0.05	0.05	0.05	0.05

(a) The company had approximately 3,028 holders of record of common shares as at January 31, 2010.

Information for Security Holders Outside Canada

Cash dividends paid to shareholders resident in countries with which Canada has an income tax convention are usually subject to Canadian non-resident withholding tax of 15%. The withholding tax rate is reduced to 5% on dividends paid to a corporation if it is a resident of the United States that owns at least 10% of the voting shares of the company.

INVESTOR INFORMATION

Stock Trading Symbols and Exchange Listing
Common shares are listed on the Toronto Stock Exchange (TSX) and New York Stock Exchange (NYSE) under the symbol SU.

Dividends
Suncor's Board of Directors reviews its dividend policy quarterly. In 2009, Suncor paid an aggregate dividend of $0.30 per common share.

Dividend Reinvestment and Common Share Purchase Plan
Suncor's Dividend Reinvestment and Common Share Purchase Plan enables shareholders to invest cash dividends in common shares or acquire additional shares through cash payments without payment of brokerage commissions, service charges or other costs associated with administration of the plan. To obtain additional information, call Computershare Trust Company of Canada at 1-877-982-8760. Information regarding the purchase plan is also available in the dividend information section of our website at www.suncor.com/dividends.

Stock Transfer Agent and Registrar
In Canada, Suncor's agent is Computershare Trust Company of Canada. In the United States, Suncor's agent is Computershare Trust Company, Inc.

Independent Auditors
PricewaterhouseCoopers LLP

Independent Reserve Evaluators
GLJ Petroleum Consultants Ltd., Sproule Associates Ltd. and RPS Energy Plc

Annual Meeting
Suncor's Annual General Meeting of shareholders will be held at 10:30 a.m. (MST) on May 4, 2010, at the Telus Convention Centre, 120 Ninth Avenue S.E., Calgary, Alberta. Presentations from the meeting will be webcast live at www.suncor.com/webcasts.

Corporate Office
Box 38, 112 - 4th Avenue S.W., Calgary, Alberta, Canada, T2P 2V5
Telephone: 403-269-8100 Toll-free number: 1-866-SUNCOR-1
Fax: 403-269-6217 E-mail: info@suncor.com

Analyst and Investor Inquiries
John Rogers, Vice President, Investor Relations
Telephone: 403-269-8670 Fax: 403-269-6217 E-mail: invest@suncor.com

For further information, to subscribe or cancel duplicate mailings
In addition to Annual and Quarterly Reports, Suncor publishes a biennial Report on Sustainability. All Suncor publications, as well as updates on company news as it happens, are available on our website at www.suncor.com. To receive Suncor news as it happens, subscribe to E-news, which can be found on our website. To order copies of Suncor's print materials call 1-800-558-9071.

If you do not receive our Annual or Quarterly Reports, but would like to receive these reports, call Computershare Trust Company of Canada at 1-877-982-8760 or visit their website at www.computershare.com. Computershare will update your account information accordingly.

Shareholders can help reduce mailing costs and paper waste by electing to receive Suncor's Annual Report and other documents electronically. To register for electronic delivery, registered shareholders should visit www.computershare.com.

GOVERNANCE AND DIRECTOR INFORMATION

Corporate Governance

Providing strategic guidance to the company, setting policy direction and ensuring Suncor is fairly reporting its progress are central to the work of Suncor's Board of Directors. The Board's oversight role encompasses Suncor's strategic planning process, risk management, standards of business conduct and communication with investors and other stakeholders. Suncor's Board is also responsible for selecting, monitoring and evaluating executive leadership and aligning management's decision making with long-term shareholder interest.

A comprehensive description of Suncor's governance practices, including a summary of any differences from those prescribed by the NYSE, is available in the company's Management Proxy Circular on Suncor's website at www.suncor.com/financialreporting or by calling 1-800-558-9071.

Mel E. Benson[(3), (4)]
(independent)
Calgary, Alberta
Director since 2000
Mel Benson is president of Mel E. Benson Management Services Inc., an international management consulting firm based in Calgary, Alberta. In 2000, Mr. Benson retired from a major international oil company. Mr. Benson is a director of Tenax Energy Inc., a director of Winalta Homes Inc. and director of the Fort McKay Group of Companies, a community trust. He is active with several charitable organizations including Hull Family Services. He is also a member of the board of governors for the Northern Alberta Institute of Technology.

Brian A. Canfield[(1), (4)]
(independent)
Point Roberts, Washington
Director since 1995
Brian Canfield is the chairman of TELUS Corporation, a telecommunications company. Beginning his career with TELUS as a telephone installer in 1956, Mr. Canfield rose through the corporate ranks to occupy positions as COO, President and CEO. Mr. Canfield is a member of the Order of Canada, a member of the Order of British Columbia and a fellow of the Institute of Corporate Directors. He was also the first businessperson to receive an honorary Doctorate of Technology from the BC Institute of Technology.

Dominic D'Alessandro[(1), (2)]
(independent)
Toronto, Ontario
Director since 2009
Dominic D'Alessandro was president and chief executive officer of Manulife Financial Corporation from 1994 to 2009 and is currently a director of CGI Group Inc. and Canadian Imperial Bank of Commerce. For his many business accomplishments, Mr. D'Alessandro was recognized as Canada's Most Respected CEO in 2004 and CEO of the Year in 2002, and was inducted into the Insurance Hall of Fame in 2008. Mr. D'Alessandro is an officer of the Order of Canada and has been appointed as a Commendatore of the Order of the Star of Italy. In 2009, he received the Woodrow Wilson Award for Corporate Citizenship and in 2005 was granted the Horatio Alger Award for community leadership.
Mr. D'Alessandro is an FCA and holds a Bachelor of Science from Concordia University in Montreal. He has also been awarded honorary doctorates from York University, the University of Ottawa, Ryerson University and Concordia University.

John T. Ferguson
(independent)
Edmonton, Alberta
Director since 1995
John Ferguson is founder and chairman of the board of Princeton Developments Ltd. and Princeton Ventures Ltd. Mr. Ferguson is also a director of Fountain Tire Ltd., the Royal Bank of Canada and Strategy Summit Ltd. In addition, he is a board member of the Alberta Bone and Joint Institute, an advisory member of the Canadian Institute for Advanced Research and chancellor emeritus and chairman emeritus of the University of Alberta. Mr. Ferguson is a fellow of the Alberta Institute of Chartered Accountants and of the Institute of Corporate Directors.

W. Douglas Ford[(2), (3)]
(independent)
Bonita Springs, Florida
Director since 2004
W. Douglas Ford was chief executive, refining and marketing for BP p.l.c. from 1998 to 2002 and was responsible for the refining, marketing and transportation network of BP as well as the aviation fuels business, the marine business and BP shipping. Mr. Ford currently serves as a director of USG Corporation and Air Products and Chemicals Inc. He is also a director of the Home Run Inn and a member of the board of trustees of the University of Notre Dame.

Richard L. George
(non-independent, management)
Calgary, Alberta
Director since 1991
Richard George is the president and chief executive officer of Suncor Energy Inc. Mr. George is also a director of the Swiss offshore and onshore drilling company Transocean Ltd. He currently serves as the Canadian Chair of the North American Competitiveness Council and he chaired the 2008 Governor General's Canadian Leadership Conference. Mr. George was named a member of the Order of Canada in 2007.

Paul Haseldonckx[(1), (4)]
(independent)
Essen, Germany
Director since 2002 (Petro-Canada 2002 to July 31, 2009)
Paul Haseldonckx was a director of Petro-Canada and a member of the management board of Veba Oel AG, Germany's largest downstream company, including the ubiquitous Aral AG gas stations in Europe. Mr. Haseldonckx represented Veba's interests at the board of the Cerro Negro joint venture, an in situ oil sands development including an upgrader, during the construction and early production phase. Mr. Haseldonckx holds a Master of Science and completed Executive Programs at INSEAD, Fontainebleau and IMD, Lausanne.

John R. Huff[(3), (4)]
(independent)
Houston, Texas
Director since 1998
John Huff is chairman of Oceaneering International Inc., an oilfield services company. He also serves as director of BJ Services Company and KBR Inc.

Jacques Lamarre[(3), (4)]
(independent)
Montreal, Quebec
Director since 2009
Jacques Lamarre was the former president and chief executive officer of SNC-Lavalin from 1996 to 2009. Mr. Lamarre is an officer of the Order of Canada, and a founding member and past chair of the Commonwealth Business Council. He is also past chair of the Board of Directors of the Conference Board of Canada and a founding member of the World Economic Forum's Governors for Engineering & Construction. Currently, he serves as a director of The Royal Bank of Canada and of P3 Canada, and as a member of the Engineering Institute of Canada, Engineers Canada and the Ordre des ingénieurs du Québec. Mr. Lamarre holds a Bachelor of Arts and a Bachelor of Arts and Science in Civil Engineering from Laval University in Quebec City. He also completed Harvard University's Executive Development Program. In addition, Mr. Lamarre holds honorary doctorates from the University of Waterloo and the University of Moncton.

Brian F. MacNeill[(1), (2)]
(independent)
Calgary, Alberta
Director since 1995 (Petro-Canada 1995 to July 31, 2009)
Brian MacNeill was a director and chairman of the board of Petro-Canada and is a Chartered Accountant, a Certified Public Accountant and holds a Bachelor of Commerce. He is a director of TELUS Corporation, West Fraser Timber Co. Ltd., Capital Power Corp and Oilsands Quest Inc. Mr. MacNeill is a member of the Canadian Institute of Chartered Accountants and the Financial Executives Institute. He is also a fellow of the Alberta Institute of Chartered Accountants and of the Institute of Corporate Directors. Mr. MacNeill is also a member of the Order of Canada.

Maureen McCaw[(3), (4)]
(independent)
Edmonton, Alberta
Director since 2004 (Petro-Canada 2004 to July 31, 2009)
Maureen McCaw was a director of Petro-Canada and is senior vice president (Edmonton) of Leger Marketing, formerly Criterion Research Corp., a company she founded in 1986. Ms. McCaw holds a Bachelor of Arts from the University of Alberta and an Institute of Corporate Directors certification (ICD.D). In addition to being president of Tinnakilly Inc. and a director of the Edmonton International Airport, Women Building Futures and Royal Alexandria Hospital, she is also

managing partner at Prism Ventures. She is a past chair of the Edmonton Chamber of Commerce and serves on a number of Alberta boards and advisory committees.

Michael W. O'Brien[(1), (2)]
(independent)
Canmore, Alberta
Director since 2002
Michael O'Brien served as executive vice president, corporate development, and chief financial officer of Suncor Energy Inc. before retiring in 2002. Mr. O'Brien is lead director of Shaw Communications Inc. In addition, he is past chair of the board of trustees for Nature Conservancy Canada, past chair of the Canadian Petroleum Products Institute and past chair of Canada's Voluntary Challenge for Global Climate Change.

James W. Simpson[(2), (3)]
(independent)
Danville, California
Director since 2004 (Petro-Canada 2004 to July 31, 2009)
James Simpson was a director of Petro-Canada and is past president of Chevron Canada Resources (oil and gas). He serves as Lead Director for Canadian Utilities Limited and is on its Corporate Governance, Nomination, Compensation and Succession Committee and Risk Review Committee, as well as being the chairman for the Audit Committee. Mr. Simpson holds a Bachelor of Science and Master of Science, and graduated from the Program for Senior Executives at M.I.T.'s Sloan School of Business. He is also past chairman of the Canadian Association of Petroleum Producers and past vice chairman of the Canadian Association of the World Petroleum Congresses.

Eira M. Thomas[(1), (2)]
(independent)
West Vancouver, British Columbia
Director since 2006
Eira Thomas assumed the role of executive chairman of Stornoway Diamond Corporation, a mineral exploration company, on January 1, 2009 after serving as chief executive officer since July 2003. Previously, Ms. Thomas was president of Navigator Exploration Corporation and chief executive officer of Stornoway Ventures Ltd. She is also a director of Strongbow Exploration Inc., Fortress Minerals Corp., Ashton Mining of Canada Inc. and Lucara Diamond Corp. In addition, Ms. Thomas is a director of the University of Toronto (U of T) Alumni Association, Lassonde Advisory Board of the U of T, Prospectors and Developers Association of Canada and the Northwest Territories and Nunavut Chamber of Mines. She also is a member of the U of T President's Internal Advisory Council.

(1) Audit Committee
(2) Governance Committee
(3) Human Resources and Compensation Committee
(4) Environment, Health, Safety and Sustainable Development Committee

CORPORATE OFFICERS[1], [2]

Richard L. George
President and Chief Executive Officer

Steven W. Williams
Chief Operating Officer

Eric Axford
Senior Vice President, Operations Support

Kirk Bailey
Executive Vice President, Oil Sands

Ron Brenneman
Executive Vice Chairman

Neil Camarta
Executive Vice President, Natural Gas

Terrence J. Hopwood
Senior Vice President and General Counsel

Boris Jackman
Executive Vice President, Refining & Marketing

Sue Lee
Senior Vice President, Human Resources and Communications

Mark Little
Senior Vice President, International & Offshore

Bart Demosky
Chief Financial Officer

Mike MacSween
Senior Vice President, In-Situ

Kevin D. Nabholz
Executive Vice President, Major Projects

Janice B. Odegaard
Corporate Secretary

Harry Roberts
Senior Vice President, Integration

Andrew Stephens
Senior Vice President, Business Services

Jay Thornton
Executive Vice President, Energy Supply, Trading and Development

Helen Wesley
Vice President and Treasurer

(1) Offices shown are positions held by the officers in relation to businesses of Suncor Energy Inc.

(2) This information reflects the positions of officers at December 31, 2009.

Box 38, 112 – 4th Avenue S.W., Calgary, Alberta, Canada T2P 2V5
tel: (403) 269-8100 fax: (403) 269-6217 info@suncor.com www.suncor.com