SUNCOR ENERGY INC. **2007** ANNUAL REPORT

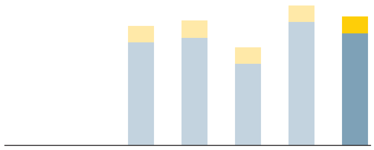
SUNCOR ENERGY is an integrated energy company strategically focused on developing one of the world's largest petroleum resource basins – Canada's Athabasca oil sands. In 2007, we celebrated the 40th anniversary of launching the commercial oil sands industry. In 2008, we expect to take the next major steps on our journey to producing more than half a million barrels of oil per day in 2012.

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 48 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 46 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

Production

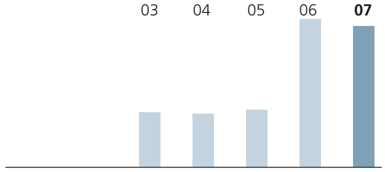
(thousands of barrels of oil equivalent per day)



per day)	03	04	05	06	**07**
Natural Gas	34.9	36.8	34.8	34.8	**35.8**
Oil Sands	216.6	226.5	171.3	260.0	**235.6**
Total	251.5	263.3	206.1	294.8	**271.4**

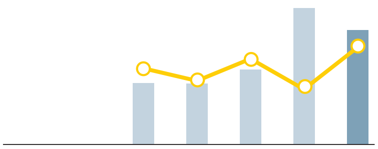
Net Earnings

($ millions)



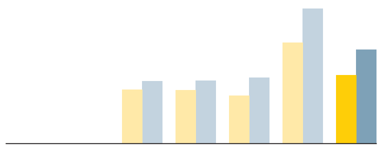
03	04	05	06	**07**
1 100	1 076	1 158	2 971	**2 832**

Cash Flow from Operations[(1)]/Net Debt



($ millions)	03	04	05	06	**07**
Cash flow from operations	2 040	2 013	2 476	4 533	**3 805**
Net debt	2 551	2 134	2 868	1 849	**3 248**

Return on Capital Employed[(1)]



(per cent)	03	04	05	06	**07**
ROCE[(2)]	16.3	16.1	14.4	30.5	**20.7**
ROCE[(3)]	18.8	19.0	19.8	40.7	**28.3**

Other Key Indicators

Year ended December 31 ($ millions)	**2007**	2006	2005	2004	2003
Financial					
Revenues	**17 933**	15 829	11 129	8 705	6 611
Capital and exploration expenditures	**5 415**	3 613	3 153	1 847	1 322
Total assets	**24 167**	18 759	15 126	11 749	10 463
Dollars per common share					
Net earnings attributable to common shareholders – basic	**6.14**	6.47	2.54	2.38	2.45
Net earnings attributable to common shareholders – diluted	**6.02**	6.32	2.48	2.33	2.29
Cash flow from operations	**8.25**	9.87	5.43	4.44	4.54
Cash dividends	**0.38**	0.30	0.24	0.23	0.1925
Market price of common stock at December 31 (closing)					
Toronto Stock Exchange (Cdn$)	**107.91**	91.79	73.32	42.40	32.50
New York Stock Exchange (US$)	**108.73**	78.91	63.13	35.40	25.06
Key ratios					
Debt to debt plus shareholders' equity (%)	**24.7**	20.9	33.6	31.3	43.2
Net debt to cash flow from operations (times)	**0.9**	0.4	1.2	1.1	1.3
Return on shareholders' equity (%)	**27.5**	39.7	21.3	24.6	32.9

(1) Non-GAAP measures.

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

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

MESSAGE TO SHAREHOLDERS

As Suncor Energy marked its 40th anniversary in the oil sands business in 2007, our employees properly celebrated the hard-won accomplishments of being an industry pioneer. But it's not in our corporate nature to spend too much time peering in the rear-view mirror. The road ahead has always been our focal point and the journey we are now on commands our full attention.

In that sense, it's fitting that 2007 was what might be called a transitional year – a time when we consolidated both the physical and financial foundations for future growth.

As we move forward, we'll need to focus all our knowledge and experience on three key tasks. First, to continue to manage our capital growth projects in a prudent and timely manner as we approach our goal of increasing Suncor's production capacity to more than half a million barrels per day (bpd) in 2012. Second, to excel in every aspect of our existing operations, working to ensure safe, reliable, cost-efficient and environmentally responsible production. Third, to lay the foundation for growth beyond 2012.

If we follow this roadmap carefully, I'm confident the journey ahead will be successful, prosperous and generate broad benefits.

Voyageur Growth Plans: 2008-2012

Seven years ago, Suncor launched an ambitious, multi-phased plan to more than double our production capacity. From the outset, 2008 was pegged as a pivotal year. This is when we expect to ramp up oil sands production capacity by 35% to 350,000 bpd.

The centerpiece of this $3.6 billion expansion is the addition of a third coker set to Suncor's Upgrader 2. We have completed the major physical tie-ins for this project and commissioning is expected in the second quarter, with ramp up to full capacity in the latter part of the year. I'm pleased to report that, even in the current high-cost environment, this project remains on budget and on schedule.

Even as we put the finishing touches on our 2008 expansion, we're working on the next phase of growth. Suncor's Board of Directors has provided final approval to our plans for new in-situ production at Firebag Stages 3 to 6, which is expected to add about 275,000 barrels of bitumen production per day by 2012.(1)

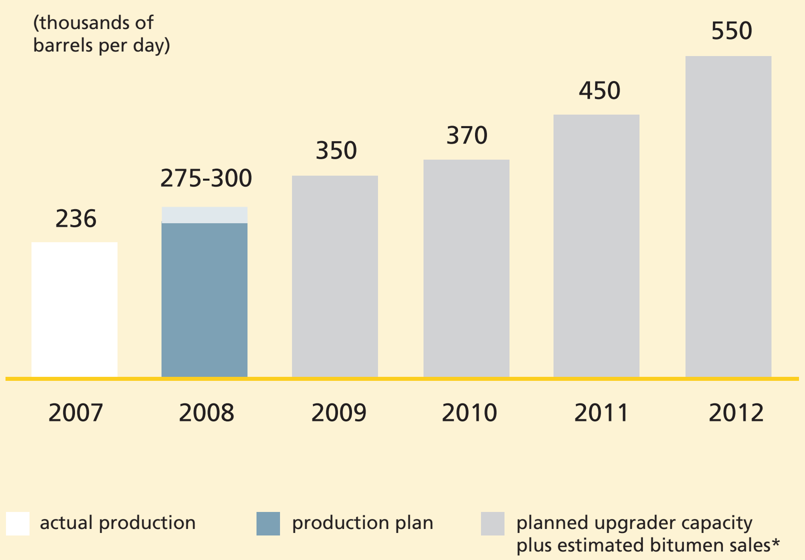
The jewel in the crown is, of course, our plan to build a third upgrader. Although we're still years away from any production, site preparation and construction of major vessels for the upgrader are already underway.

Taken together, these planned expansions are expected to allow Suncor, Canada's oil sands pioneer, to remain an industry leader. Today, Suncor accounts for about 30% of all upgraded product coming out of the oil sands. This growth strategy should see us maintain that market share in 2012, even as many new corporate players invest in the oil sands.

The total projected capital spending for this growth program is considerable – $20.6 billion. But while the level of investment is massive, our approach to development remains measured. The increased revenues expected from post-2008 production levels will help bankroll our plans and, although we expect to take on more debt, we believe we can maintain a strong debt to cash flow ratio at crude oil prices of US$60 WTI.

(1) Regulatory approval for Firebag Stages 4 to 6 is expected in 2008.

In addition, although this is the largest capital investment program in Suncor's history, I'm proud that Suncor is maintaining one of the lowest capital costs in the industry for each new barrel of oil produced – and we also expect to maintain our position among the lowest cash operating costs per barrel in the oil sands industry.



* Capacity is not an indicator of annual production, which could vary due to scheduled and unscheduled maintenance, schedule to complete capital projects and other factors.

Suncor's competitive track record and confidence in our future plans all come back to something I like to call "the Suncor way." Our company pioneered what has become an industry model for integrated planning. Suncor's crude production, upgrading, refining and marketing operations are all connected in a single strategy, with each component complementing the other. By fully integrating our assets and operational capabilities – including natural gas production facilities and renewable energy projects – we enjoy a built-in advantage to help weather commodity price swings and other economic fluctuations.

But in an industry where the typical mega-project requires billions of dollars in upfront capital spending and can take between five and ten years from conception to completion, we've learned it pays to build the necessary organization and processes internally and maintain them from project to project.

That's the thinking behind establishing our Major Projects group – an in-house team of experts in engineering, procurement and construction responsible for delivering growth projects on schedule, on budget and at the highest standards of safety and reliability. This approach helps keep mega-project expertise where it belongs – inside the company. Our team and its experience stays with Suncor and the suppliers and contractors who support us.

Among the innovative strategies pursued by our Major Projects group is a multi-year, staged approach to growth. Our experience has taught us that breaking up project components and assigning a dedicated team to each piece helps control budgets and schedules. For example, although our third upgrader is estimated to cost $11.6 billion, the project will actually be divided into several smaller components, each with a management team, detailed construction plans and tight budget controls.

With a Major Projects team to build and manage future growth, Suncor's business units can focus on the everyday challenge of providing safe, reliable and cost-effective production operations. And this challenge is more critical than ever. The recent years of a weak Canadian dollar that might have helped manufacturing and export businesses overcome productivity gaps have ended. Simply put, there are no short-cuts to success.

Operational Excellence

Growth is good, but it means little if we sacrifice the integrity of existing operations. That is why we continually strive to excel in all that we do.

One clear signal of our renewed focus on operational excellence was the creation, in 2007, of the new position of chief operating officer. While others work to address our ambitious growth plans, COO Steve Williams is charged with focusing on achieving top performance from our existing operations. His priorities are straight-forward: cost control, reliability, safety and improved environmental performance. Steve and the operations committee have established performance targets in each of these areas and we expect them to consistently deliver.

It's impossible to overstate the importance of efficiently running 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.

A key part of operational excellence is to meet our production targets while minimizing our impact on the environment. And as shareholders know, we had some challenges in 2007 on this score.

At our oil sands operations, sulphur emissions in 2007 exceeded ambient air quality guidelines. While the emission levels were within Alberta occupational health and safety limits, they did cause odours.

Suncor responded with plans to bring our operations into compliance, including upgrades to emission control equipment and reduced discharges to tailings ponds. We also introduced processing changes and undertook comprehensive air monitoring.

Our determination to put this situation right – and to make sure it doesn't happen again – is in keeping with our company's core values. Suncor didn't just lead the current surge in oil sands development – we committed very early on that we would work to do so in an environmentally responsible fashion.

For more than 15 years, we've pursued a vision of sustainable development. Suncor was the first oil sands company to voluntarily adopt an internal Climate Change Action Plan and report annually on our progress. We have made industry-leading investments in renewable energy sources, including wind power and biofuels. And we've realized reductions in the intensity of water use and air emissions company-wide. For example, total water use at our oil sands operations has been reduced by about 40% over the past five years and Suncor plans to proceed with our next major expansion without requesting any increase to our water licence. On greenhouse gases, emissions per barrel at our oil sands plant have been cut in half compared to 1990 levels. However, while emissions per barrel at Suncor have been slashed, we face ongoing challenges as total emissions have increased with the expansion of our operations.

That's why, as the scale of our business grows, Suncor's vision for sustainable development is more relevant than ever. We intend to remain ahead of the curve by instilling a conservation ethic across our operations and by continuing to harness technology to improve environmental performance in every aspect of future growth.

Growth Beyond Half a Million Barrels per Day

With so much focus over the last decade on reaching our half million barrel per day production capacity target, it's sometimes been easy to think of this as an endpoint rather than part of a much broader story. But Suncor's story doesn't end in 2012, and so it's now time to start talking about the foundations being laid for plans to grow beyond our 550,000 bpd target.

Some initial building blocks are already in place, including plans for the Voyageur South mine, to be located southwest of our existing operation. Expanded mine development would serve a dual purpose. In its early production phase, the bitumen from this project is expected to provide additional feedstock flexibility for our planned half million barrel per day upgrading capacity. In the longer term, it is expected to provide a reliable source of bitumen for future increases in crude oil production.

Suncor has also made progress on securing land near Edmonton that would be suitable for a potential fourth upgrader. But decisions on the timing and ultimate location of such a project are still some time away.

One of the keys to future success is emerging technologies. For example, in our mining operations, we plan to continue deployment of mobile mining technology, which would eliminate most of the haul fleet for transporting ore and should help efforts to manage both costs and emissions. The potential for similar savings is behind Suncor's investment in next-generation gasification technology, which could turn petroleum coke, a by-product of the upgrading process, into synthetic natural gas with related carbon emissions captured and sequestered.

Another key to success is enhancing downstream integration. We've completed major improvements to our Sarnia, Ontario and Commerce City, Colorado refineries, significantly increasing the amount of oil sands crude that can be refined and further optimizing our internal efficiencies.

We also continue to work with industry partners to support projects that will extend our reach to new markets. In this regard, the Gulf of Mexico – home to the largest refining complex in the world – holds obvious attractions. The Gulf already has the capability to run a wide variety of oil sands product slates. And as uncertainty in other U.S. supply sources continues, we expect Canada's oil sands will increasingly be seen as a reliable supplier for this region.

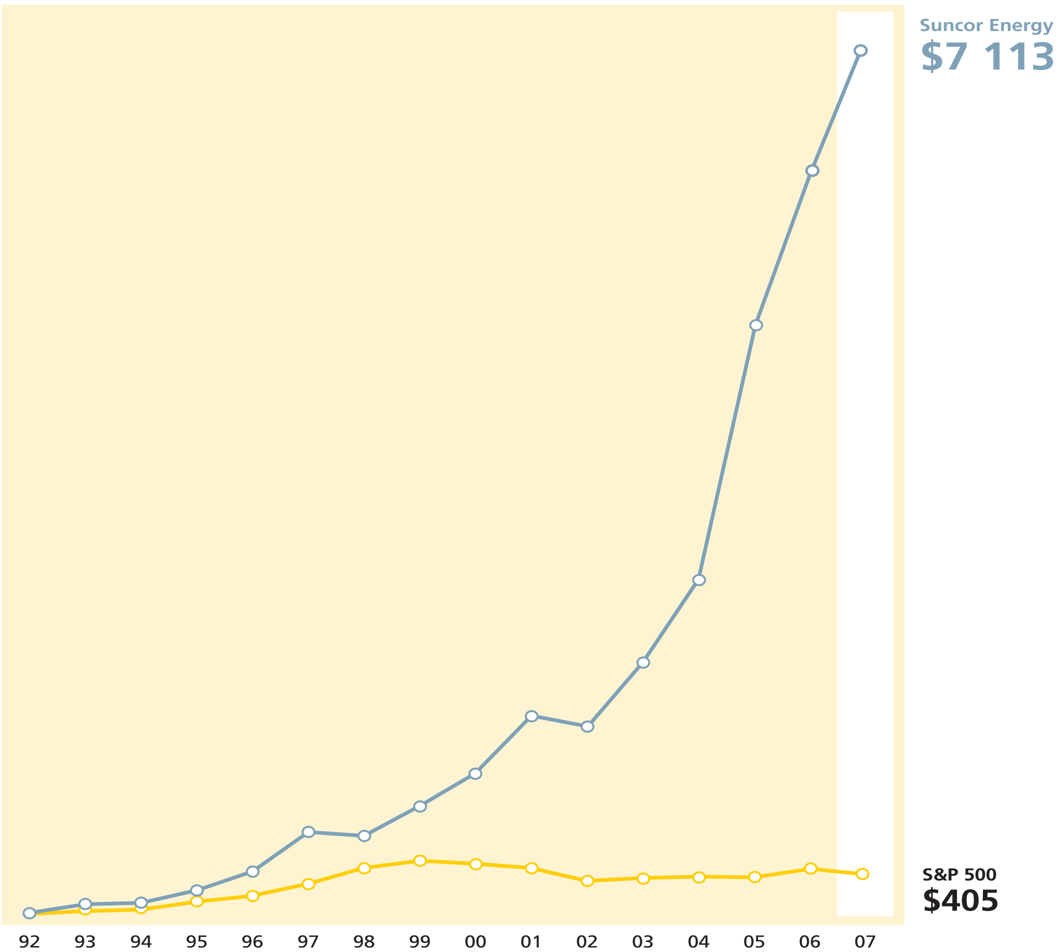
Another opportunity is to connect oil sands production to tanker terminals on Canada's west coast to gain access to California markets and, ultimately, to Asia. Providing oil sands crude to energy-hungry Asian economies is, to be sure, a long-term proposition. But with an estimated 15.5 billion barrels of remaining recoverable resources[(2)] on Suncor's leases, we've learned to think very much about the long-term.

Critical to everything we do are Suncor's 6,500 employees, among the most talented and experienced corporate teams in a highly competitive industry. I also remain indebted to Suncor's Board of Directors, who oversee all aspects of governance and are outstanding stewards of shareholders' interests. They excel at challenging management to exceed expectations – and I would like to recognize them for their guidance and support.

(2) See page 30

Together, we face some big challenges on the road ahead. But together, I'm confident we will continue to make this a journey of success. We've got the resources, the capital foundation, the people and the plan. And most of all, we've got the track record to show what can be achieved with hard work, foresight and determination. 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



Delivering Value

Assuming the reinvestment of dividends, a $100 investment in Suncor on March 18, 1992, the day we became publicly traded, would have grown to more than $7,100 at the end of 2007.

OUR SCORECARD

2007 – What we promised and what we delivered

Achieve annual oil sands production of 260,000 to 270,000 bpd at a cash operating cost average of $21.50 to $22.50 per barrel. Unscheduled maintenance resulted in annual production of 235,600 bpd and cash operating costs of $27.80 per barrel.

Increase natural gas production to an average 215 to 220 mmcf equivalent per day. New wells and improved pipe access resulted in daily average production of 215 mmcf equivalent per day in 2007.

Advance plans for increased bitumen supply. In July, Suncor applied for regulatory permission to develop the Voyageur South mine extension. Construction began on Firebag Stage 3, while engineering and procurement were advanced for further expansion.

Safely complete all expansion tie-ins. A 50-day shutdown of Upgrader 2 to tie in facilities related to planned production expansion was completed safely and on schedule. At the Sarnia refinery, a shutdown to tie in modified equipment to allow the processing of up to 40,000 bpd of oil sands sour crude was also completed safely, with facilities ramping up in early 2008.

Advance plans for increased upgrader capacity. Construction of facilities planned to increase production capacity to 350,000 bpd was 95% complete by year-end. Progress was also made on detailed engineering, and procurement and fabrication of long-lead time materials for a planned third upgrader – the centerpiece of plans to achieve more than half a million bpd in 2012.

Focus on enterprise-wide efficiency. A single-vendor, performance-based maintenance contract for all Canadian facilities was put in place, while non-core IT services were transferred to external experts. Recruitment branding leveraged Suncor's competitive strengths and stronger workforce planning processes were initiated to improve competitiveness and productivity.

Continue to focus on safety. Lost-time injuries, a key performance indicator, dropped to levels significantly below industry averages.

Maintain a strong balance sheet. Suncor's year-end net debt was $3.2 billion, compared to cash flow of $3.8 billion, maintaining a strong debt to cash flow ratio.

Continue to pursue energy efficiencies, greenhouse gas offsets and new, renewable energy projects. Suncor made a strategic investment in the development of next-generation gasification technology as an alternative to natural gas energy. The company also commissioned its fourth – and largest – wind power project in 2007.

2008 – Our targets and how we'll get there

Achieve annual oil sands production of 275,000 to 300,000 bpd at a cash operating cost average of $25 to $27 per barrel. Planned production increases with the commissioning of an expansion to Upgrader 2 and a strong focus on production reliability are key to managing operating costs.

Target natural gas production of 205 to 215 mmcf equivalent per day. New wells targeted for production are expected to provide a strong start to the year.

Advance plans for increased bitumen supply. Meet regulatory requirements to allow ramp up of expansion to Firebag Stages 1 and 2, commence construction of Stage 3 and receive regulatory approval to proceed with Stages 4 to 6. New third-party bitumen supplies also expected in 2008.

Advance plans for increased crude oil production. With Board of Directors approval for construction of a third upgrader granted in early 2008, target completion of majority of engineering design specification and maintain construction schedule.

Continue to focus on safety. Increase focus on identifying and reducing potential process hazards.

Focus on efficiency. Safely complete planned modifications to Upgrader 2 aimed at ensuring reliable, full capacity production. A planned maintenance shutdown to Upgrader 1, part of $1.5 billion in maintenance capital spending in 2008, is also expected to improve reliability going forward.

Maintain a strong balance sheet. While net debt is expected to rise with capital spending of $7.5 billion, plan to maintain a strong debt to cash flow ratio and protect future cash flow with strategic hedging of up to 30% of planned production.

Continue efforts to reduce environmental impact intensity. Investments planned to reduce sulphur emissions at oil sands facilities while plans for increased rate of in-situ recovery targets reduced water use intensity.

Continue to pursue energy efficiencies, greenhouse gas offsets and new, renewable energy projects. In oil sands operations, advance work on more efficient extraction technology. Advance renewable energy portfolio.

This Management's Discussion and Analysis (MD&A) contains forward-looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. See page 48 for additional information.

This MD&A should be read in conjunction with Suncor's 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 cash flow from operations, return on capital employed (ROCE) and cash and total operating costs per barrel referred to in this MD&A are not prescribed by GAAP and are outlined and reconciled in Non-GAAP Financial Measures on page 46.

Certain prior year amounts 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.

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.

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

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

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 18.

SUNCOR OVERVIEW AND STRATEGIC PRIORITIES

Suncor Energy Inc. is an integrated energy company headquartered in Calgary, Alberta. We operate three 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 byproducts.
- **Natural gas**, located in western Canada, is a conventional exploration and development operation, focused primarily on the production of natural gas. Its natural gas production offsets Suncor's purchases for internal consumption at our oil sands operations.
- **Refining and marketing**, Suncor's downstream operations located in Ontario and Colorado, produce and market the company's refined products to industrial, commercial and retail customers.

In addition to Suncor's integrated oil sands-focused business activities, the company is also investing in renewable energy opportunities. Suncor is a partner in four wind power projects and operates Canada's largest ethanol plant.

Suncor's strategic priorities are:

Operational:

- Developing our oil sands resource base through mining and in-situ technology and supplementing Suncor 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.
- Managing environmental and social performance by mitigating impact to air, water and land while also earning continued stakeholder support for our ongoing operations and growth plans.
- Maintaining a strong focus on worker, contractor and community health and safety.

Financial:

- Controlling costs through a strong focus on operational excellence, economies of scale and continued management of engineering, procurement and construction of major projects.
- Reducing risk associated with natural gas price volatility by producing natural gas volumes that offset purchases for internal consumption.
- Ensuring appropriate levels of debt and capital spending are in place to support growth in a fiscally responsible manner.

2007 Overview

- Combined oil sands and natural gas production in 2007 was 271,400 barrels of oil equivalent (boe) per day, compared to 294,800 boe per day in 2006. Oil sands production averaged 235,600 barrels per day (bpd) in 2007, compared to 260,000 bpd in 2006. Oil sands cash operating costs averaged $27.80 per barrel during 2007, compared to $21.70 per barrel in 2006. Natural gas production averaged 215 million cubic feet equivalent (mmcfe) per day, compared to an average 209 mmcfe per day in 2006.
- Suncor continued to make progress on plans to expand Upgrader 2 and increase production capacity to 350,000 bpd, with construction completion targeted in the second quarter of 2008 and ramp-up to full capacity expected in the fourth quarter. As of December 31, 2007, the project was 95% complete.
- In July, Suncor filed a regulatory application for the Voyageur South mine extension. Bitumen produced at the proposed project is expected to provide additional feedstock flexibility.
- In Suncor's downstream operations, investments were made to integrate up to 40,000 bpd of oil sands sour crude into the company's Sarnia, Ontario refinery.
- In September, Suncor commissioned its fourth wind farm. The 76-megawatt facility located near Ripley, Ontario is the company's largest wind power project.
- Capital spending in 2007 totalled $5.4 billion. Net debt at year-end 2007 was $3.2 billion, compared to $1.8 billion at the end of 2006.
- Suncor achieved a company-wide return on capital employed of 28.3% in 2007, compared to 40.7% in 2006 (excluding capitalized costs for major projects in progress).

SELECTED FINANCIAL INFORMATION

Annual Financial Data

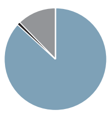
Year ended December 31 ($ millions except per share)	**2007**	2006	2005
Revenues	**17 933**	15 829	11 129
Net earnings	**2 832**	2 971	1 158
Total assets	**24 167**	18 759	15 126
Long-term debt	**3 811**	2 363	2 984
Dividends on common shares	**162**	127	102
Net earnings attributable to common shareholders per share – basic	**6.14**	6.47	2.54
Net earnings attributable to common shareholders per share – diluted	**6.02**	6.32	2.48
Cash dividends per share	**0.38**	0.30	0.24

Outstanding Share Data

At December 31, 2007 (thousands)	
Number of common shares	462 783
Number of common share options	27 000
Number of common share options – exercisable	7 276

Net Earnings [1]

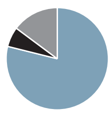
Year ended December 31
($ millions)



	07	06	05
Oil sands	**2 434**	2 783	957
Natural gas	**25**	106	155
Refining and marketing	**345**	235	174

Cash Flow from Operations [1],[2]

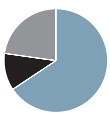
Year ended December 31
($ millions)



	07	06	05
Oil sands	**3 092**	3 917	1 916
Natural gas	**248**	281	412
Refining and marketing	**580**	443	363

Capital Employed [1],[2],[3]

At December 31
($ millions)



	07	06	05
Oil sands	**6 541**	5 015	4 436
Natural gas	**1 153**	857	562
Refining and marketing	**2 270**	1 818	796

(1) Excludes Corporate and Eliminations segment.

(2) Non-GAAP measures.

(3) Excludes major projects in progress.

CONSOLIDATED FINANCIAL ANALYSIS

This analysis provides an overview of our consolidated financial results for 2007 compared to 2006. For a detailed analysis, see the various business segment discussions.

Net Earnings

Our net earnings were $2.832 billion in 2007, compared with $2.971 billion in 2006 (2005 – $1.158 billion). Excluding the impacts of the reduction of federal and Alberta income tax rates, net insurance proceeds (relating to a January 2005 fire), unrealized foreign exchange gains on the company's U.S. dollar denominated long-term debt, and project start-up costs, earnings were $2.239 billion in 2007, compared to $2.350 billion in 2006 (2005 – $850 million). The decrease in net earnings primarily reflects the impact of scheduled and unscheduled maintenance that reduced crude oil production and increased operating expenses. The largest impacts on financial results were a scheduled 50-day maintenance shutdown to portions of Suncor's oil sands operation to tie in new facilities related to a planned expansion and a scheduled 120-day shutdown to portions of the Sarnia refinery to tie in new sour crude processing facilities. These impacts were partly offset by higher realized crude oil prices.

Net Earnings Components[1]

Year ended December 31 ($ millions, after-tax)	**2007**	2006	2005
Net earnings before the following items:	**2 239**	2 350	850
Impact of income tax rate reductions on opening future income tax liabilities	**427**	419	—
Oil sands fire accrued insurance proceeds[2]	**—**	232	293
Unrealized foreign exchange gains on U.S. dollar denominated long-term debt	**215**	—	31
Project start-up costs	**(49)**	(30)	(16)
Net earnings as reported	**2 832**	2 971	1 158

(1) This table highlights some of the factors impacting Suncor's after-tax net earnings. For comparability purposes, readers should rely on the reported net earnings that are prepared and presented in the consolidated financial statements and notes in accordance with Canadian GAAP.

(2) Net accrued property loss and business interruption proceeds net of income taxes and Alberta Crown royalties.

Industry Indicators

(Average for the year)	**2007**	2006	2005
West Texas Intermediate (WTI) crude oil US$/barrel at Cushing	**72.30**	66.20	56.55
Canadian 0.3% par crude oil Cdn$/barrel at Edmonton	**76.65**	73.05	69.00
Light/heavy crude oil differential US$/barrel WTI at Cushing less Western Canadian Select at Hardisty	**22.25**	21.45	20.20
Natural gas US$/thousand cubic feet (mcf) at Henry Hub	**6.90**	7.25	8.55
Natural gas (Alberta spot) Cdn$/mcf at AECO	**6.60**	7.00	8.50
New York Harbour 3-2-1 crack US$/barrel[1]	**13.70**	9.80	9.50
Exchange rate: US$/Cdn$	**0.93**	0.88	0.83

(1) New York Harbour 3-2-1 crack is an industry indicator measuring the margin on a barrel of oil for gasoline and distillate. It is calculated by taking two times the New York Harbour gasoline margin plus the New York Harbour distillate margin and dividing by three.

Revenues were $17.933 billion in 2007, compared with $15.829 billion in 2006 (2005 – $11.129 billion). The increase was primarily due to the following factors:

- Energy marketing and trading revenues increased to $2.883 billion in 2007, compared to $1.582 billion in 2006. The increase is due primarily to a larger volume of crude oil traded and higher average crude oil prices.
- A reduction in planned refinery maintenance in 2007 compared to 2006 led to increased refinery utilization and sales in our downstream operations. Downstream operations also benefited from stronger refining and retail margins reflecting supply constraints in the Ontario and U.S. Rocky Mountain regions.
- Average crude oil prices were higher in 2007 than in 2006. A 9% increase in average U.S. dollar WTI benchmark prices increased the selling price of oil sands crude oil production. In addition, strengthening price realizations for our sweet and sour blends relative to WTI also increased our revenue.

Partially offsetting these increases were the following:

- Oil sands production and sales volumes were lower during 2007, mainly as a result of the planned shutdown of Upgrader 2. The 50-day outage was required to tie in new facilities related to our planned expansion of oil sands production capacity.

- A 6% increase in the average US$/Cdn$ exchange rate negatively impacted realizations on our crude oil sales basket. Because crude oil is primarily sold based on U.S. dollar benchmark prices, a strengthening Canadian dollar produced a corresponding reduction in the Canadian dollar value of our products.
- The absence of net insurance proceeds relating to a January 2005 fire at our oil sands operations (2006 – $436 million).

Overall, reduced production in our oil sands operations decreased revenues by approximately $634 million. Higher price realizations on our crude oil products increased total revenues by approximately $470 million.

The cost to purchase crude oil and crude oil products was $5.935 billion in 2007, compared to $4.678 billion in 2006 (2005 – $4.164 billion). The increase was primarily due to the following:

- Higher benchmark crude oil prices. This had the largest impact on product purchases for our refining and marketing business, as WTI increased by more than US$6.00/bbl over the prior year.
- Increased inputs of crude oil feedstock to meet higher demand from our refineries, and additional purchases of refined products to meet sales commitments during planned maintenance outages in our oil sands and downstream operations.

Operating, selling and general expenses were $3.375 billion in 2007 compared with $3.043 billion in 2006 (2005 – $2.437 billion). The primary reasons for the increase were:

- An increase in the costs associated with maintenance activities.
- Higher stock-based compensation expenses resulting from the launch of our new performance stock option plan in September 2007 and continued growth in our share price.

Transportation and other expenses were $198 million in 2007, compared to $212 million in 2006 (2005 – $152 million). The decrease in transportation costs was primarily due to reduced volumes shipped out of the Fort McMurray area.

Depreciation, depletion and amortization (DD&A) was $864 million in 2007, compared to $695 million in 2006 (2005 – $568 million). The increase primarily reflects the construction and commissioning of new operating units at both our oil sands operation and our Sarnia refinery.

Royalty expenses were $691 million in 2007, compared with $1,038 million in 2006 (2005 – $555 million). The decrease in 2007 was primarily due to an increase in capital expenditures incurred in our oil sands operations, lower sales volumes and also the absence of net insurance proceeds (relating to a January 2005 fire). These factors were partially offset by increased crude oil prices. For a discussion of Crown royalties, see pages 19 and 20.

Taxes other than income taxes were $648 million in 2007, compared to $595 million in 2006 (2005 – $529 million). The increase was primarily due to higher sales volumes subject to Canadian fuel excise taxes in our refining and marketing operations.

Financing income was $211 million in 2007, compared with expenses of $39 million in 2006 (2005 – income of $15 million). The increase in financing income was primarily due to the foreign exchange gains on our U.S. dollar denominated long-term debt. Although interest expense related to our long-term debt increased from the prior year due to additional debt issuance during 2007, it was all capitalized, resulting in no total interest expense in 2007, compared to $21 million in 2006. Capitalized interest was $189 million in 2007, compared to $129 million in 2006.

Income tax expense was $513 million in 2007 (15% effective tax rate), compared to $835 million in 2006 (21% effective tax rate) and $694 million in 2005 (37% effective tax rate). The decrease in the effective tax rate was primarily due to a decrease in statutory rates, an increase in the deductibility of Crown royalties, as well as an increase in the revaluation of opening future income tax liabilities due to the enactment of tax rate reductions. Income tax expense in both 2007 and 2006 included the effects of reductions in tax rates that reduced opening future income tax liabilities as follows:

Impact of Tax Rate Changes on Segmented Earnings

($ millions, increase (decrease) in earnings)	**2007** Oil Sands	**2007** Natural Gas	**2007** Refining and Marketing	**2007** Corporate and Eliminations	**2007** Total	2006 Total	2005 Total
Federal	**413**	**39**	**17**	**(42)**	**427**	292	—
Alberta	—	—	—	—	—	127	—
	413	**39**	**17**	**(42)**	**427**	419	—

Reflects fourth quarter 2007 federal rate reduction of 3.5%, second quarter 2007 federal rate reduction of 0.5%, second quarter 2006 federal rate reduction of 3.1% and second quarter 2006 Alberta rate reduction of 1.5%.

Excluding these adjustments, income tax expense in 2007 was $940 million (28% effective tax rate) and $1,254 million in 2006 (33% effective tax rate).

Corporate Earnings

After-tax net corporate earnings were $28 million in 2007, compared to expense of $153 million in 2006 (2005 – $128 million expense). Excluding the impact of group elimination entries, actual after-tax net corporate earnings were $31 million in 2007 (2006 – $147 million expense; 2005 – $139 million expense). The net earnings in the corporate segment in 2007, compared to net expense in 2006, were primarily due to the unrealized foreign exchange gains on our U.S. denominated long-term debt as a result of the stronger Canadian dollar. After-tax unrealized foreign exchange gains on our U.S. denominated long-term debt were $215 million in 2007, compared to nil in 2006 (2005 – gain of $31 million). In addition, the increase in future tax expense as a result of the revaluation of future income taxes was smaller in 2007 – an expense of $42 million in 2007, compared to an expense of $68 million in 2006. These factors were partially offset by an increase in stock-based compensation expense. Corporate had a net cash deficiency of $659 million in 2007, compared with $403 million in 2006 (2005 – $107 million). The additional deficiency in 2007 was primarily due to increases in working capital of $187 million.

Breakdown of Net Corporate Earnings (Expense)

Year ended December 31 ($ millions)	**2007**	2006	2005
Corporate earnings (expense)	**31**	(147)	(139)
Group eliminations	**(3)**	(6)	11
Total	**28**	(153)	(128)

Consolidated Cash Flow from Operations

Cash flow from operations was $3.805 billion in 2007, compared to $4.533 billion in 2006 (2005 – $2.476 billion). The decrease in cash flow from operations was primarily due to the same factors that impacted net earnings, as well as an increase in cash income taxes during 2007 compared to 2006.

Dividends

Total dividends paid during 2007 were $0.38 per share, compared with $0.30 per share in 2006 (2005 – $0.24 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. In the second quarter of 2007, the Board approved an increase in the quarterly dividend to $0.10 per share from $0.08 per share.

Quarterly Financial Data

($ millions except per share)	**2007 Quarter ended** Dec 31	Sept 30	June 30	Mar 31	2006 Quarter ended Dec 31	Sept 30	June 30	Mar 31
Revenues	**4 958**	**4 666**	**4 358**	**3 951**	3 787	4 114	4 070	3 858
Net earnings	**963**	**677**	**641**	**551**	358	682	1 218	713
Net earnings attributable to common shareholders per share								
Basic	**2.08**	**1.47**	**1.39**	**1.20**	0.78	1.48	2.65	1.56
Diluted	**2.04**	**1.43**	**1.36**	**1.17**	0.76	1.45	2.59	1.52

Variations in quarterly net earnings during 2007 and 2006 were due to a number of factors:

- Oil sands production and sales volumes decrease during periods of planned and unplanned maintenance.
- Changes in benchmark commodity prices throughout 2006 and 2007. WTI averaged US$72.30 per barrel (bbl) in 2007, compared to US$66.20/bbl in 2006.
- 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.
- Reductions in federal corporate tax rates during the second and fourth quarters of 2007 increased net earnings by $67 million and $360 million, respectively, and reductions in both the federal and Alberta corporate tax rates during the second quarter of 2006 increased 2006 net earnings by $419 million.
- Insurance proceeds were received in the second and fourth quarters of 2006 of $205 million and $27 million after tax, respectively, related to a January 2005 fire at our oil sands operations.
- Oil sands Crown royalties varied as a result of changes in crude oil commodity prices and the extent and timing of eligible capital and operating expenditures.
- The continued strengthening of the Canadian dollar through 2007 unfavourably impacted the realized commodity prices on our products sold in U.S. dollars, reducing the Canadian dollar revenues earned. Changes in the exchange rate also led to unrealized gains on our U.S. dollar denominated long-term debt in 2007.
- Refined product prices fluctuated as a result of global and regional supply and demand, as well as seasonal demand variations. In our downstream operations, seasonal fluctuations have historically reflected higher demand for vehicle fuels and asphalt in summer and heating fuels in winter. Refining and retail margins strengthened in 2007, compared to 2006 as a result of tighter supply of refined products in both the Ontario and U.S. Rocky Mountain markets.

LIQUIDITY AND CAPITAL RESOURCES

Our capital resources consist primarily of cash flow from operations and available lines of credit. Our level of earnings and cash flow from operations depends on many factors, including commodity prices, production/sales levels, downstream margins, operating expenses, taxes, royalties, and US$/Cdn$ exchange rates.

At December 31, 2007, our net debt (short and long-term debt less cash and cash equivalents) was $3.248 billion, compared to $1.849 billion at December 31, 2006. The increase in debt levels was primarily a result of increased capital spending to fulfill our growth strategies.

During the first quarter of 2007, the company repaid maturing $250 million of 6.80% Medium Term Notes using commercial paper borrowings. Also during the first quarter, the company issued 5.39% Medium Term Notes with a principal amount of $600 million under an outstanding $2 billion debt shelf prospectus. These notes bear interest, which is paid semi-annually, and mature on March 26, 2037. The net proceeds received were used for general corporate purposes, including reducing short-term borrowings, supporting our ongoing capital spending program and for working capital requirements.

During the second quarter of 2007, the company issued 6.50% Notes with a principal amount of US$750 million under an outstanding US$2 billion debt shelf prospectus. These notes bear interest, which is paid semi-annually, and mature on June 15, 2038. The net proceeds received were used for general corporate purposes, including reducing short-term borrowings, supporting our ongoing capital spending program and for working capital requirements.

Also during the second quarter, the company's $300 million bilateral credit facility was amended and extended by one year to 2008 and the credit limit was increased by $30 million to $330 million total funds available. A $2 billion syndicated credit facility was renegotiated and extended by one year to have a five-year term expiring in June 2012 and the company's commercial paper program limit was increased by $300 million to $1.5 billion from $1.2 billion. Additionally, a $15 million revolving demand credit facility was renegotiated and increased by $15 million to $30 million.

During the third quarter of 2007, the company repaid $150 million of maturing 6.10% Medium Term Notes using commercial paper borrowings. Also during the third quarter, the company issued additional 6.50% Notes with a principal amount of US$400 million under our outstanding US$2 billion debt shelf prospectus. These notes bear interest, which is paid semi-annually, and mature on June 15, 2038. The net proceeds received were used for general corporate purposes, including reducing short-term borrowings, supporting our ongoing capital spending program and for working capital requirements.

Undrawn lines of credit at December 31, 2007 were approximately $1.6 billion. Suncor's current long-term senior debt ratings are A-, with a stable trend by Standard & Poor's; A(low), Under Review – Developing by Dominion Bond Rating Service; and A3, with a stable trend by Moody's Investors Service.

Interest expense on debt continues to be influenced by the composition of our debt portfolio, and we are benefiting from short-term floating interest rates remaining at low levels. To manage fixed versus floating rate exposure, we have entered into interest rate swaps with investment grade counterparties. At December 31, 2007, we had $200 million of fixed-rate to variable-rate interest swaps (December 31, 2006 – $600 million).

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

We believe we will have the capital resources to fund our 2008 capital spending program of $7.5 billion and to meet current working capital requirements. If additional capital is required, we believe adequate additional financing will be available at commercial terms and rates. Suncor expects similar levels of company-wide capital spending over the next several years. (Actual spending is subject to change due to such factors as internal and external approvals and capital availability.)

We anticipate our growth plan will be financed through cash flow from operations, credit facilities and access to debt capital markets. Refer to the discussion under Risk Factors Affecting Performance on page 21 for additional factors that may have an impact on our ability to generate funds to support investing activities.

Aggregate Contractual Obligations

		Payments Due by Period			
($ millions)	Total	2008	2009-2010 (aggregate)	2011-2012 (aggregate)	Later Years
Fixed-term debt and commercial paper (1)	3 747	522	—	500	2 725
Interest payments on fixed-term debt and commercial paper (1)	5 022	233	409	397	3 983
Capital leases	324	9	18	20	277
Employee future benefits (2)	612	43	99	113	357
Asset retirement obligations (3)	2 231	190	269	93	1 679
Non-cancellable capital spending commitments (4)	446	446	—	—	—
Operating lease agreements, pipeline capacity and energy services commitments (5)	7 310	330	770	792	5 418
Total	19 692	1 773	1 565	1 915	14 439

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 $3,225 million of U.S. and Canadian dollar denominated debt that is redeemable at our option. Maturities range from 2011 to 2038. Interest rates vary from 5.39% to 7.15%. We entered into various interest rate swap transactions maturing in 2011 that resulted in an average effective interest rate in 2007 of 5.7% on $200 million of our Medium Term Notes. Approximately $522 million of commercial paper with an effective interest rate of 4.8% was issued and outstanding at December 31, 2007.

(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) Non-cancellable capital commitments related to capital projects totalled approximately $446 million at the end of 2007. In addition to capital projects, we spend maintenance capital to sustain our current operations. In 2008, we anticipate spending approximately $1.5 billion towards sustaining capital.

(5) Includes transportation service agreements for pipeline capacity, including tankage for the shipment of crude oil from Fort McMurray to Hardisty, Alberta, as well as energy services agreements to obtain a portion of the power and steam generated by a cogeneration facility owned by a major energy company. Non-cancellable operating leases are for service stations, office space and other property and equipment.

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.

In addition, a very limited number of our commodity purchase agreements, off-balance sheet arrangements (for a discussion of these arrangements see page 19) and 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.

At December 31, 2007, we were in compliance with all covenants and our debt ratings were investment grade.

Significant Capital Project Update

We spent $5.4 billion on capital and exploration expenditures in 2007, compared to $3.6 billion in 2006 (2005 – $3.2 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.

Project	Plan	Cost Estimate $ millions(1)	Estimate % Accuracy	Spent to Date	Estimated % Complete Engineering	Estimated % Complete Construction	Target Completion Date
Coker unit	Expected to increase production capacity by 90,000 bpd	2 100	+13/−7	2 120	100	95	Q2 2008
Steepbank extraction plant	Location and new technologies aimed at improving operational performance	850	+10/−10	320	96	25	2009
Naphtha unit	Increases sweet product mix	650	+10/−10	345	95	20	2009
North Steepbank mine expansion	Expected to generate about 180,000 bpd of bitumen	400	+10/−10	60	50	10	2009
Firebag sulphur plant(2)	Supports emission abatement plan at Firebag; capacity to support Stages 1-6	340	+10/−10	80	65	5	2009
Voyageur program: Firebag	Expansion of Firebag 3-6 is expected to increase bitumen supply.	9 000	+18/−13	1 440(3)			
	– Stage 3				75	20	2009
	– Stage 4(2)				25	—	2010
	– Stage 5(2)				10	—	2011
	– Stage 6(2)				—	—	2011
Voyageur program: Upgrader 3	Expected to increase production capacity by 200,000 bpd	11 600	+12/−8	1 075(3)	20	1	2011(4)

(1) Excludes commissioning and start-up costs.

(2) Pending regulatory approval.

(3) Spending to date includes procurement of major project components. For Firebag Stage 3, procurement at year-end 2007 was 70% complete; for Stage 4, 45% complete; and for Stage 5, 2% complete. For Upgrader 3, procurement was 20% complete.

(4) Construction completion targeted in 2011 with ramp-up to full capacity during 2012.

The previous table contains forward-looking information and users of this information are cautioned that the actual timing, amount of the final capital expenditures and expected results for each of these projects may vary from the plans disclosed in the table. The target completion dates and cost estimates are based on information and assumptions from the procurement, design and engineering phases of the projects. The more preliminary the project, the greater the range of uncertainty that is projected in connection with the project.

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 pages 21 to 26. The forward-looking information in the preceding paragraphs and table should not be taken as an estimate, forecast or prediction of future events or circumstances.

Guarantees, Variable Interest Entities and Off-Balance Sheet Arrangements

At December 31, 2007, we had various indemnification agreements with third parties, as described below.

We have a multiple-party securitization program in place to sell, on a revolving, fully serviced and limited recourse basis, up to $170 million (2006 – $170 million) of accounts receivable having a maturity of 45 days or less. At December 31, 2007, no outstanding accounts receivable had been sold under the program (2006 – $170 million). Under the recourse provisions, we indemnify certain counterparties against credit losses, and in 2007 such indemnification did not exceed $42 million. A contingent liability has not been recorded for this indemnification as we believe we have no significant exposure to credit losses. Proceeds received from new securitizations and proceeds from collections reinvested in securitizations on a revolving basis for the year ended December 31, 2007, were $170 million and approximately $1,530 million, respectively. We recorded an after-tax loss of approximately $4 million on the securitization program in 2007 (2006 – $2 million; 2005 – $4 million).

We have agreed to indemnify holders of our outstanding U.S. dollar denominated debt securities and our credit facility lenders for added costs related to taxes, assessments or other government charges or conditions, including any required withholding amounts. Similar indemnity terms apply to the receivables securitization program, and certain facility and equipment leases.

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

In 1999, we entered into an equipment sale and leaseback arrangement with a Variable Interest Entity (VIE) for proceeds of $30 million. The VIE's sole asset was the equipment sold to it and leased back by Suncor. The VIE was consolidated effective January 1, 2005. The initial lease term covered a period of seven years, and had been accounted for as an operating lease. The company repurchased the equipment in 2006 for $21 million. At December 31, 2007, the VIE did not have any assets or liabilities.

Oil Sands Crown Royalties

Under the current Province of Alberta generic oil sands royalty regime (the "Generic Regime"), Alberta Crown royalties for oil sands projects are currently payable at the rate of 25% of the difference between a project's annual gross revenues net of related transportation costs (R), less allowable costs including allowable capital expenditures (the R-C Royalty), subject to a minimum royalty, currently 1% of R. The Alberta government has classified Suncor's current oil sands operations as two distinct "projects" for royalty purposes.

Royalties on our current Firebag in-situ project are under the Generic Regime, and assessed based on bitumen value. In October 2007, the government of Alberta announced a new royalty framework which, if enacted by the government, will increase royalty rates under the Generic Regime to a sliding scale royalty of 25% – 40% of R-C, subject to minimum royalty of 1% – 9% of R, depending on oil price. In both cases, the sliding scale royalty would move with increases in WTI prices from Cdn$55 to the maximum rate at a WTI price of Cdn$120.

Royalties on our base oil sands mining and associated upgrading operations (the "base operations") are assessed on the R-C calculation as follows:

- Continues to be 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 will apply from Suncor's 1997 option to transition to the Generic Regime. The royalty rates will remain the same, but will apply to a revised R-C, where R will be based on bitumen value and C would exclude substantially all upgrading costs.
- Commencing January 1, 2010, pursuant to the Suncor Royalty Amending Agreement we entered into with the government of Alberta in January 2008, the new royalty rates in the Generic Regime 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 up to 1.2% of R (assuming the government enacts their proposed framework). In addition, the Suncor Royalty Amending Agreement provides Suncor with certainty for various matters, including the bitumen valuation methodology, allowed costs, royalty in-kind and certain taxes, generally until 2016.

- In 2016 and subsequent years, the royalty rates for all of our oil sands operations (our base operation and our Firebag in-situ project) will be the rates prescribed under the Generic Regime.

Anticipated Oil Sands Royalty Expense Based on Certain Assumptions

The table below shows the potential royalty payment at various WTI crude prices, for both mining and in-situ operations, as a percentage of gross revenues.

Oil Sands Mining and In-Situ Royalties

WTI Price/bbl US$	**70**	**80**	**90**
Natural gas (Alberta spot) Cdn$/mcf at AECO	6.71	6.98	7.22
Light/heavy oil differential of WTI at Cushing less Maya at the U.S. Gulf Coast US$	15.89	18.72	20.86
US$/Cdn$ exchange rate	0.95	1.00	1.05
Crown Royalty Expense (based on percentage of total oil sands revenue) %			
2008 – Mining synthetic crude oil, in-situ bitumen (25% and 1% min)	9-10	9-10	10-11
2009 – Bitumen (mining old rates – 25% and 1% min; in-situ new rates)	7-8	8-9	9-10
2010 to 2012 – Bitumen (new rates – cap 30% for mining)	8-10	9-11	9-11

The foregoing table contains forward-looking information and users of this information are cautioned that actual Crown royalty expense may vary from the percentages or ranges disclosed in the table. The royalty percentages or ranges disclosed in the table were developed using the following assumptions: current agreements with the government of Alberta, royalty rates proposed by the government of Alberta, current forecasts of production, capital and operating costs, and the commodity prices and exchange rates described in the table. If WTI prices rise beyond $90, Suncor anticipates Firebag in-situ royalties may be higher than disclosed in the table.

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

(i) Pursuant to the new royalty framework, the government intends to establish a permanent generic "bitumen valuation methodology" (BVM) for determining the "R" related to bitumen. The Crown is consulting with stakeholders and independent advisors with a decision on the methodology anticipated by June 30, 2008. Final determination of that methodology may have an impact on royalties payable to the Crown;

(ii) The government also announced its intention to assess and recommend improvements in its systems, structures and resources supporting the collection, verification and reporting of provincial royalties. This assessment is expected to be completed by March 31, 2008. Steps taken by the government thereafter may affect the calculation of royalties; and

(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 to the Generic Regime 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.

The forward-looking information in the preceding paragraphs and table should not be taken as an estimate, forecast or prediction of future events or circumstances.

Natural Gas Crown Royalties

Royalty rates on natural gas production are currently capped at 30% for gas discovered in 1974 or later and 35% for gas discovered prior to 1974. These rates are subject to reduction if gas prices drop below $3.70/Gigajoule ($3.89/mcf), a gas well qualifies for a deep gas royalty holiday incentive, or a gas well qualifies as a low productivity well. In October 2007, the government of Alberta announced a new royalty framework which, if enacted by the government, will change royalty rates beginning in 2009. The announced framework 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%. If enacted as proposed, the new royalty framework would negatively impact the economics of deep gas wells in the Alberta Foothills which may cause management to reduce drilling activity in this area.

Cash Income Taxes

The 2007 federal budget proposes to phase out the accelerated capital cost allowance that was originally intended to offset some of the risk associated with the large capital investment required to bring oil sands projects to production. The accelerated capital cost allowance will continue to be available for assets acquired before 2012 on major projects where major construction commenced before March 19, 2007. We believe Suncor's Voyageur expansion, targeted for completion in 2012, will fall under the current accelerated capital cost allowance provisions. If not, the accelerated capital cost allowance will be gradually phased out between 2011 and 2015.

Cash income taxes are sensitive to crude oil and natural gas commodity price volatility and the timing of recognition of capital expenditures for income tax purposes. Based on current forecasts of production, capital and operating costs, and the commodity prices and exchange rates described in the table "Oil Sands Mining and In-situ Royalties" on page 20, we anticipate our effective income tax rate to be within 2% of the statutory income tax rate for each respective year beyond 2007. Based on the enacted tax rates and assuming that there are no further changes to the current income tax regime, we estimate we will have cash income taxes of 30-50% of our effective tax rate during 2008 to 2010 inclusive. Thereafter, we do not anticipate any significant cash income tax until the middle of the next decade. Our outlook on cash income tax is a forward looking statement and users of this information are cautioned that actual cash income taxes may vary from our outlook.

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 growth plans, extreme weather, regional labour issues and other issues discussed within Risk Factors Affecting Performance for each of our business segments. As a company we identify risks in four principal categories: 1) Operational; 2) Financial; 3) Legal and Regulatory; and 4) Strategic. 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. The internal review is completed annually to ensure all significant risks are identified and appropriately managed.

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, among others, may result in a high degree of price volatility. For example, from 2005 to 2007 the monthly average price for benchmark WTI crude oil ranged from a low of US$46.85/bbl to a high of US$94.63/bbl. During the same three-year period, the natural gas AECO benchmark monthly average price ranged from a low of $4.45/mcf to a high of $12.74/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.

SENSITIVITY ANALYSIS [1]

	2007 Average	Change	Approximate Change in Cash Flow from Operations ($ millions)	Approximate Change in After-Tax Earnings ($ millions)
Oil Sands				
Price of crude oil ($/barrel)[2]	74.01	US$ 1.00	69	50
Sweet/sour differential ($/barrel)	10.13	US$ 1.00	30	22
Sales (bpd)	234 700	1 000	13	9
Natural Gas				
Price of natural gas ($/mcf)[2]	6.32	0.10	5	4
Sales (mmcf/d)	196	10	13	3
Consolidated				
Exchange rate: US$/Cdn$	0.93	0.01		
Effect on oil sands operations			51	36
Effect on U.S. denominated long-term debt				(15)
Total exchange rate impact			51	21

(1) The sensitivity analysis shows the main factors affecting Suncor's annual cash flow from operations and earnings based on actual 2007 operations. The table illustrates the potential financial impact of these factors applied to Suncor's 2007 results. A change in any one factor could compound or offset other factors.

(2) Includes the impact of hedging activities.

Derivative Financial Instruments

Effective January 1, 2007, new accounting standards were implemented relating to financial instruments. For a more detailed discussion, see Change in Accounting Policies on page 32. Adoption of these changes did not significantly impact earnings.

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 contracts, including swaps, forwards and options, to earn trading and marketing revenues.

The estimated fair values of financial instruments have been determined based on the company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction. Upon initial recognition, each financial asset and financial liability instrument is recorded at fair value, adjusted for any transaction costs.

Derivative contracts, excluding those considered as normal purchases and normal sales, are required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge each period, 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 each period, 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 related hedged item is recognized. 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.

Commodity Hedging Activities To provide an element of stability to future earnings and cash flow, we have Board of Director approval to fix a price or range of prices for up to approximately 30% of our total planned production of crude oil for specified periods of time. Our crude oil hedging program is subject to periodic management reviews to determine appropriate hedge requirements in light of our tolerance for exposure to market volatility as well as the need for stable cash flow to finance future growth.

Settlement of our hedging contracts result 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 collars, if market rates are within the range of the hedged contract prices, the option contracts making up the collar will expire with no exchange of cash. Cash received or paid offsets corresponding decreases or increases in our sales revenues or product purchase costs. 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 and Comprehensive Income. In 2007, there was a $3 million decrease in net earnings due to the settlement of crude oil hedges, compared to no impact in 2006 (2005 – decrease of $337 million).

Crude oil hedge contracts outstanding at December 31, 2007 were as follows:

	Quantity (bpd)	Average Price (US$/bbl) [a]	Revenue Hedged (Cdn$ millions) [b]	Hedge Period [c]
Costless collars	10 000	59.85 – 101.06	216 – 365	2008

(a) Average price of crude oil costless collars is WTI per barrel at Cushing, Oklahoma.

(b) The revenue hedged is translated to Cdn$ at the year-end exchange rate and is subject to change as the US$/Cdn$ exchange rate fluctuates during the hedge period.

(c) Original hedge term is for the full year.

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

Financial Hedging Activities We periodically enter into interest rate swap contracts as part of our strategy to manage exposure to interest rates. The interest rate swap contracts involve an exchange of floating rate and fixed rate interest payments between ourselves and investment grade counterparties. The differentials on the exchange of periodic interest payments are recognized as an adjustment to interest expense.

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. We had the following interest rate swap transactions during 2007.

Description of Swap Transaction	Principal Swapped ($ millions)	Swap Maturity	2007 Effective Interest Rate	2006 Effective Interest Rate
Swap of 6.70% Medium Term Notes to floating rates	200	2011	5.7%	5.2%
Swap of 6.80% Medium Term Notes to floating rates	250	2007	6.0%	6.0%
Swap of 6.10% Medium Term Notes to floating rates	150	2007	4.7%	5.3%

In 2007, these interest rate swap transactions reduced pretax financing expense by $4 million, compared to a reduction of $6 million in 2006 (2005 – $14 million reduction).

In addition to our interest rate swap contracts, the company also manages variability in market interest rates and foreign exchange rates during periods of debt issuance through the use of interest rate swaps and foreign exchange forward contracts.

The net pretax loss associated with hedge ineffectiveness in 2007 was $1 million.

Fair Value of Hedging Derivative Financial Instruments The fair value of hedging derivative financial instruments is the estimated amount, based on broker quotes and/or internal valuation models, that we would receive (pay) to terminate the contracts. Such amounts, which also represent the unrealized gain (loss) on the contracts, were as follows at December 31:

($ millions)	**2007**	2006
Revenue hedge swaps and collars	**(11)**	22
Fixed to floating interest rate swaps	**8**	16
Specific hedges of individual transactions	**12**	(4)
Fair value of outstanding hedging derivative financial instruments	**9**	34

Energy Marketing and Trading Activities In addition to derivative contracts used for hedging activities, the company uses physical and financial energy derivatives to earn trading and marketing revenues. These trading activities are accounted for using the mark-to-market method, with the results reported as revenue and as energy marketing and trading expenses in the Consolidated Statements of Earnings and Comprehensive Income.

The net pretax earnings (loss) for the years ended December 31 were as follows:

Net Pretax Earnings (Loss) ($ millions)	**2007**	2006
Physical energy contracts trading activity	**21**	41
Financial energy contracts trading activity	**(3)**	(3)
General and administrative costs	**(4)**	(3)
Total	**14**	35

The fair value of unsettled energy marketing and trading instruments is the estimated amount, based on broker quotes and/or internal valuation models, that we would receive (pay) to terminate the contracts. Such amounts, which also represent the unrealized gain (loss) on the contracts, were as follows at December 31:

($ millions)	**2007**	2006
Energy trading assets	**18**	16
Energy trading liabilities	**21**	13
Net energy trading assets (liabilities)	**(3)**	3

The change in fair value of energy marketing and trading net assets during 2007 was as follows:

($ millions)	**2007**
Fair value of contracts at December 31, 2006	3
Fair value of contracts realized during 2007	**29**
Fair value of contracts entered into during the year	**(56)**
Changes in values attributable to market price and other market changes	**21**
Fair value of contracts outstanding at December 31, 2007	**(3)**

Counterparty Credit Risk 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. Our exposure is limited to those counterparties holding derivative contracts with positive fair values at the reporting date. We minimize this risk by entering into agreements primarily with investment grade counterparties. Risk is also minimized through regular management review of the potential exposure to and credit ratings of such counterparties.

At December 31, the company had exposure to credit risk with counterparties as follows:

($ millions)	**2007**	2006
Derivative contracts not accounted for as hedges	**18**	16
Derivative contracts accounted for as hedges	**20**	35
Total	**38**	51

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 required before initiating most new projects or undertaking significant changes to existing operations. We were issued a new 10-year operating approval in connection with our oil sands base operations in August 2007. In addition to these specific, known requirements, we expect future changes to environmental legislation, including anticipated legislation for air pollution (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 impacts of oil sands development in the province;
- manufacture, import, storage, treatment and disposal of hazardous or industrial waste and substances;
- the need to reduce or stabilize various emissions to air and withdrawals of, and discharges to, water;
- issues relating to global climate change, land reclamation and restoration;
- water use and water disposal;
- 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.

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.

On March 8, 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 are subject to this legislation. The act calls for intensity reductions of 12% commencing July 1, 2007.

In compliance with this new legislation, Suncor filed applications in December 2007 to establish baseline intensities for our oil sands facility. In March 2008, Suncor must file compliance reports that show what actions the company took during the year to offset intensities. Mitigation options available to Suncor include internal emission reductions, utilizing offset projects or contributing to a government climate change emission management fund.

For the compliance period of July 1, 2007 to December 31, 2007, the compliance costs to Suncor are estimated at between \$3 million and \$5 million. Final costs will be determined with the company's March 2008 compliance report filing to the province.

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

In April 2007, the Canadian federal government introduced the Clean Air regulatory framework, which is expected to regulate both greenhouse gas emissions and air pollutants from industrial emitters. Suncor has been engaging in the ongoing consultations on this framework. In support of developing regulation, the federal government has required the submission of production, operations and emissions information for each of Suncor's operations by May 31, 2008. The financial impact of this proposed legislation will be dependent on the details of Clean Air Act regulations.

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 and alternate forms of energy such as wind power and biofuels, accelerating land reclamation, the installation of new emission abatement equipment and pursuing other opportunities such as carbon capture and sequestration.

Regulatory Requirements at Oil Sands Suncor is working to decrease emissions at our oil sands operations. At our in-situ operation, high emissions resulted in intervention by both Alberta Environment and the Alberta Energy and Utilities Board. Until regulators can be assured emissions are stable at compliant levels, production at the in-situ operation has been capped at approximately 42,000 barrels of bitumen per day. As a result, commissioning of units to increase the bitumen production capacity of Firebag Stages 1 and 2 by about 35% have been delayed. Suncor's production outlook for 2008 reflects this constraint. Suncor's planned \$340 million Firebag sulphur plant is expected to play a role in managing sulphur emissions for existing and planned in-situ developments.

At Suncor's base plant we are taking steps to comply with an environmental protection order issued by Alberta Environment. The order relates to emissions at Suncor's oil sands plant that have exceeded air quality standards and which are resulting in increased odours from the operation. To correct the problem, Suncor is upgrading its emission control equipment and reducing discharges to the tailings ponds. The company has also introduced processing changes and is undertaking a more comprehensive air monitoring program.

Any additional regulatory requirements placed on us due to these, or other, matters could have a material effect on our business and results of operations.

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. To reclaim tailings ponds, we are using a process referred to as consolidated tailings (CT) technology. At this time, no ponds have been fully reclaimed using this technology. The success of the CT technology and time to reclaim the tailings ponds could increase or decrease our current asset retirement cost estimates. We continue to monitor and assess other possible technologies and/or modifications to the CT process now being used.

For the Millennium, Steepbank, and North Steepbank Extension mines, we have posted irrevocable letters of credit equal to approximately \$227 million with Alberta Environment, representing security for the maximum reclamation liability in the period April 1, 2007 through March 31, 2008. For Suncor's oil sands mining leases 86 and 17, we are required to and have posted annually with Alberta Environment an irrevocable letter of credit equal to \$0.03 per bbl of crude oil produced as security for the estimated cost of our reclamation activity. This letter of credit equalled $14 million at December 31, 2007 (2006 – $14 million). For more information about our reclamation and environmental remediation obligations, refer to Asset Retirement Obligations in the Critical Accounting Estimates section on page 30.

A new Mine Liability Management Program (MLMP) is under review by the Province of Alberta. The MLMP would involve increased reporting of progressive reclamation, measurement of MLMP assets against MLMP liabilities and measurement of reserve life. Partial security could be required if reclamation targets are not met and full security may eventually be required.

Regulatory Approvals Before proceeding with most major projects, we must obtain regulatory approvals. The regulatory approval process 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.

Reserves Estimates

As a Canadian issuer, we are subject to the reporting requirements of Canadian securities regulatory authorities, including the reporting of our reserves in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). However, we have received an exemption from Canadian securities administrators permitting us to report our reserves in accordance with U.S. disclosure requirements. Pursuant to U.S. disclosure requirements, we disclose net proved conventional oil and gas reserves, including natural gas reserves and bitumen reserves from our Firebag in-situ leases, using constant dollar cost and pricing assumptions. As there is no recognized posted bitumen price, these assumptions are based on a posted benchmark oil price, adjusted for transportation, gravity and other factors that create the difference ("differential") in price between the posted benchmark price and Suncor's bitumen. Both the posted benchmark price and the differential are generally determined as of a point in time, namely December 31 ("Constant Cost and Pricing"). Reserves from our Firebag in-situ leases are reported as barrels of bitumen, using these Constant Cost and Pricing assumptions (see Required U.S. Oil and Gas and Mining Disclosure – Proved Conventional Oil and Gas Reserves for net proved conventional oil and gas reserves).

Pursuant to U.S. disclosure requirements, we also disclose gross and net proved and probable mining reserves. The estimates of our gross and net mining reserves are based in part on the current mine plan and estimates of extraction recovery and upgrading yields. We report mining reserves as barrels of synthetic crude oil based on a net coker, or synthetic crude oil, yield from bitumen of 78.5% for proven reserves, and 80% for proved plus probable reserves. The lower yield rate applied to proven reserves reflects historical operational levels. The 80% proved plus probable reserves yield rate reflects anticipated yield levels once operational performance issues have been addressed.

During 2005, we reached an agreement with the Government of Alberta finalizing the terms of our option to transition to the generic bitumen-based royalty regime commencing in 2009, allowing us to prepare an estimate of our net mining reserves. The estimate of our net mining reserves reflects the value of Alberta Crown, overriding, and freehold royalty burdens under constant December 31 pricing and our exercise of the option electing to transfer to a bitumen-based Crown royalty effective at the beginning of 2009 (See Required U.S. Oil and Gas and Mining Disclosure – Proved and Probable Oil Sands Mining Reserves for both gross and net, proved and probable mining reserves). Our Firebag in-situ leases are subject to Crown royalty based on bitumen, rather than synthetic, crude oil. As there is currently no legislated methodology for determining bitumen value for Alberta Crown royalty purposes, bitumen value for determining royalties has been assumed to correspond to Firebag bitumen sales to our upgrader. However, determination of bitumen value for royalty purposes is currently under review by the Government of Alberta.

In October 2007, the Government of Alberta proposed changes to the royalty regime. In January 2008, Suncor entered into a Royalty Amending Agreement to transition to the new royalty framework assuming the government enacts their proposed changes. Neither the government's proposed changes nor our Royalty Amending Agreement have been reflected in the following reserve estimates. For a full discussion of our Crown royalties, see Oil Sands Crown Royalties and Natural Gas Crown Royalties on pages 19 and 20.

In addition to reporting our reserves in accordance with U.S. disclosure requirements, the exemption issued by Canadian securities regulatory authorities permits us to provide voluntary additional disclosure. We provide this additional voluntary disclosure to show aggregate proved and probable oil sands reserves, including both mining reserves and Firebag reserves. In our voluntary disclosure we report our aggregate reserves on the following basis:

- Gross and net proved and probable mining reserves are consistent with required US mining disclosures, however the voluntary disclosure reflects normalized constant dollar cost and pricing assumptions. These assumptions use a posted benchmark oil price as at December 31, but apply a differential generally intended to represent a normalized annual average for the year ("Annual Average Differential Pricing"), rather than a point in time differential, in accordance with CSA Staff Notice 51-315 (reported as barrels of synthetic crude oil based upon a net coker, or synthetic crude oil, yield from bitumen of 78.5% for proved reserves and 80% for proved plus probable reserves); and
- Gross and net proved and probable bitumen reserves from Firebag in-situ leases, evaluated based on Annual Average Differential Pricing. Bitumen reserves estimated on this basis are subsequently converted, for aggregation purposes only, to barrels of synthetic crude oil based on a net coker, or synthetic crude oil, yield from bitumen of 80% for proved and proved plus probable reserves.

Accordingly, our voluntary disclosures of reserves from our Firebag in-situ leases will differ from our required U.S. disclosure in four ways. Reserves from our Firebag in-situ leases under our voluntary disclosure:

(a) are disclosed on a gross basis as well as the required net basis under U.S. disclosure requirements;

(b) are converted from barrels of bitumen under U.S. disclosure requirements to barrels of synthetic crude oil for aggregation purposes;

(c) include proved plus probable reserves, rather than proved reserves only under U.S. disclosure requirements; and

(d) are evaluated based on 2007 Annual Average Differential Pricing assumptions, in accordance with CSA Staff Notice 51-315, versus Constant Cost and Pricing assumptions pursuant to U.S. disclosure requirements.

Comparisons of reserve estimates under Required U.S. Oil and Gas Mining Disclosure and Voluntary Oil Sands Reserve Disclosure may show material differences based on the pricing assumptions used, whether the reserves are reported as barrels of bitumen or barrels of synthetic crude oil, whether probable reserves are included, and whether the reserves are reported on a gross or net basis. These differences were significant for 2005 and 2007 reporting given the considerably lower constant price assumptions. At December 31, 2006, there was no difference arising from pricing. Refer to Voluntary Oil Sands Reserves and Resources Disclosure – Estimated Gross and Net Proved and Probable Oil Sands Reserves Reconciliations.

In addition to our required and voluntary reserves disclosures, we have also elected to disclose our best estimate remaining recoverable resources for both mining and in-situ at December 31, 2007. These disclosures follow the requirements in NI 51-101.

All of our reserves and resources have been evaluated as at December 31, 2007, by independent petroleum consultants, GLJ Petroleum Consultants Ltd. (GLJ). In reports dated February 19, 2008, for oil sands mining, and February 11, 2008, for oil sands in-situ (collectively referred to herein as "GLJ Oil Sands Reports"), GLJ evaluated our resources and our proved and probable reserves on our oil sands mining and Firebag in-situ leases pursuant to U.S. disclosure requirements using Constant Cost and Pricing assumptions.

Estimates in the GLJ Oil Sands Reports consider recovery from leases for which regulatory applications have been submitted and no impediment to the receipt of regulatory approval is expected. The mining reserve estimates are based on a detailed geological assessment and also consider industry practice, drill density, production capacity, extraction recoveries, upgrading yields, mine plans, operating life, project implementation commitments and regulatory constraints.

For Firebag in-situ reserve estimates, GLJ considered similar factors such as our regulatory approval or likely impediments to the receipt of pending regulatory approval, project implementation commitments, detailed design estimates, detailed reservoir studies, demonstrated commercial success of analogous commercial projects and drill density. Our proved reserves are delineated to within 80-acre spacing with 3D seismic control (or 40-acre spacing without 3D seismic control) while our probable reserves are delineated to within 160-acre spacing without 3D seismic control. The major facility expenditures to develop our proved undeveloped reserves have been approved by our Board. Plans to develop our probable undeveloped reserves in subsequent phases are under way but have not yet received final approval from our Board.

In a report dated January 10, 2008 ("GLJ NG Report"), GLJ also evaluated our proved reserves of natural gas, natural gas liquids and crude oil (other than reserves from our mining leases and the Firebag in-situ reserves) as at December 31, 2007.

Our reserves estimates will continue to be impacted by both drilling data and operating experience, as well as technological developments and economic considerations.

Net reserves represent Suncor's undivided percentage interest in total reserves after deducting Crown royalties, freehold and overriding royalty interests. Reserve estimates are based on assumptions about future prices, production levels, operating costs, capital expenditures, and the current government of Alberta royalty regime. These assumptions reflect market and regulatory conditions, as required, at December 31, 2007, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Required U.S. Oil and Gas and Mining Disclosure

Proved and Probable Oil Sands Mining Reserves

	Proved		Probable		Proved & Probable	
Millions of barrels of synthetic crude oil [1]	Gross [2]	Net [3]	Gross [2]	Net [3]	Gross [2]	Net [3]
December 31, 2006	1 709	1 507	634	564	2 343	2 071
Revisions of previous estimates	(1)	103	106	149	105	252
Extensions and discoveries	–	–	–	–	–	–
Production	(74)	(66)	–	–	(74)	(66)
December 31, 2007	**1 634**	**1 544**	**740**	**713**	**2 374**	**2 257**

(1) Synthetic crude oil reserves are based upon a net coker, or synthetic crude oil, yield from bitumen of 78.5% for proved reserves, and 80% for proved plus probable reserves. The lower yield rate applied to proved reserves reflects historical operational levels that have fallen below management expectations. The 80% proved plus probable reserves yield rate reflects a return to management's target levels once operational performance issues have been addressed.

(2) Our gross mining reserves are based in part on our current mine plan and estimates of extraction recovery and upgrading yields, rather than an analysis based on constant dollar or forecast pricing and cost assumptions.

(3) Net mining reserves reflect the value of Crown, freehold and overriding royalty burdens under constant December 31 pricing and incorporates our exercised option to elect to transfer to a bitumen-based Crown royalty effective at the beginning of 2009. Neither the current proposed Alberta royalty regime changes nor our Royalty Amending Agreement have been incorporated. If enacted, at current oil prices we expect our future royalty payments to increase and our net reserves to decrease. Refer to the Alberta Crown Royalties risk, as outlined in the Risk Factors section of our AIF.

Proved Conventional Oil and Gas Reserves

The following data is provided on a net basis in accordance with the provisions of the Financial Accounting Standards Board's Statement No. 69. This statement requires disclosure about conventional oil and gas activities only, and therefore our oil sands mining activities are excluded, while in-situ Firebag reserves are included.

Net Proved Reserves [1]

Crude Oil, Natural Gas Liquids and Natural Gas

Constant cost and pricing as at December 31	Oil sands business: Firebag – crude oil (millions of barrels of bitumen) [2] [3]	Natural gas business: crude oil and natural gas liquids (millions of barrels)	Total (millions of barrels)	Natural gas business: natural gas (billions of cubic feet)
December 31, 2006	903	7	910	426
Revisions on previous estimates [4]	68	–	68	4
Improved recovery [5]	99	–	99	–
Purchases of minerals in place	–	–	–	19
Extensions and discoveries	–	–	–	33
Production	(13)	(1)	(14)	(53)
Sales of minerals in place	–	–	–	(1)
December 31, 2007	**1 057**	**6**	**1 063**	**428**

(1) Our undivided percentage interest in reserves, after deducting Crown royalties, freehold royalties and overriding royalty interests. Our Firebag leases are only subject to Crown royalties.

(2) Although we are subject to Canadian disclosure rules in connection with the reporting of our reserves, we have received exemptive relief from Canadian securities administrators permitting us to report our proved reserves in accordance with U.S. disclosure practices. See Reliance on Exemptive Relief in our AIF.

(3) We have the option of selling the bitumen production from these leases or upgrading the bitumen to synthetic crude oil.

(4) Natural gas infill drilling included in total revisions for 2007 was 16 billion cubic feet (bcf), (2006 – 11 bcf; 2005 – 23 bcf).

(5) Improved recovery recognizes a portion of our Firebag Stage 3 expansion project.

Voluntary Oil Sands Reserves Disclosure

Oil Sands Mining and Firebag In-Situ Reserves Reconciliation

The following tables set out, on a gross and net basis, a reconciliation of our proved and probable reserves of synthetic crude oil from our oil sands mining leases and bitumen, converted to synthetic crude oil for comparison purposes only, from our in-situ Firebag leases, from December 31, 2006, to December 31, 2007, based on the GLJ Oil Sands Reports.

Estimated Gross Proved and Probable Oil Sands Reserves Reconciliation

	Oil Sands Mining Leases (1), (2)			Firebag In-Situ Leases (1), (3)			Total Mining and In-Situ (3)
Millions of barrels of synthetic crude oil (1)	Proved	Probable	Proved & Probable	Proved	Probable	Proved & Probable	Proved & Probable
December 31, 2006	1 709	634	2 343	803	1 907	2 710	5 053
Revisions of previous estimates	(1)	106	105	(17)	(5)	(22)	83
Improved recovery	–	–	–	80	(66)	14	14
Extensions and discoveries	–	–	–	–	–	–	–
Production	(74)	–	(74)	(11)	–	(11)	(85)
December 31, 2007	**1 634**	**740**	**2 374**	**855**	**1 836**	**2 691**	**5 065**

Estimated Net Proved and Probable Oil Sands Reserves Reconciliation

	Oil Sands Mining Leases (1), (2)			Firebag In-Situ Leases (1), (3)			Total Mining and In-Situ (3)
Millions of barrels of synthetic crude oil (1)	Proved	Probable	Proved & Probable	Proved	Probable	Proved & Probable	Proved & Probable
December 31, 2006	1 507	564	2 071	722	1 639	2 361	4 432
Revisions of previous estimates	11	108	119	(15)	(7)	(22)	97
Improved recovery	–	–	–	72	(60)	12	12
Extensions and discoveries	–	–	–	–	–	–	–
Production	(66)	–	(66)	(11)	–	(11)	(77)
December 31, 2007	**1 452**	**672**	**2 124**	**768**	**1 572**	**2 340**	**4 464**

(1) Synthetic crude oil reserves are based upon a net coker, or synthetic crude oil, yield from bitumen of 78.5% for proven reserves, and 80% for proved plus probable reserves under oil sands mining leases and 80% for both proved reserves and proved plus probable reserves for Firebag in-situ leases. Virtually all of our bitumen from the oil sands mining leases is upgraded into synthetic crude oil. However, we have the option of selling the bitumen produced from our Firebag in-situ leases directly to the market where strategic opportunities exist. Accordingly, these bitumen reserves are converted to synthetic crude oil for aggregation purposes.

(2) Our gross mining reserves are evaluated in part, based on the current mine plan and estimates of extraction recovery and upgrading yields, rather than an analysis based on constant dollar or forecast pricing assumptions. Net mining reserves reflect the relative value of Crown, freehold and overriding royalty burdens based on 2007 Annual Average Differential Pricing assumptions in accordance with CSA Staff Notice 51-315 and reflects our exercised option to elect to transfer to a bitumen-based Crown royalty effective at the beginning of 2009. Neither the current proposed Alberta royalty regime changes, nor our Royalty Amending Agreement have been incorporated.

(3) Under Required U.S. Oil and Gas and Mining Disclosure, we reported proved reserves from our Firebag in-situ leases. The disclosure in the table above reports proved reserves from these leases and differs in the following four ways. Reserves from our Firebag in-situ leases under our voluntary disclosure:

(a) are disclosed on a gross basis as well as the required net basis under U.S. disclosure requirements;

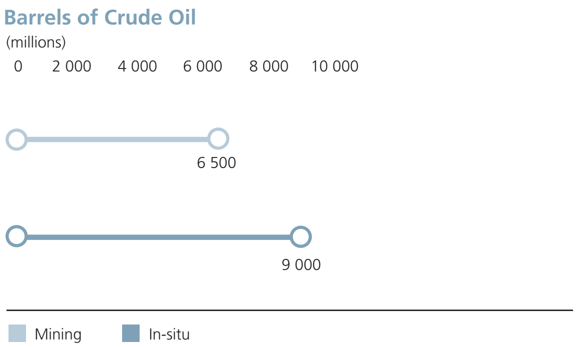
(b) are converted from barrels of bitumen to barrels of synthetic crude oil in this table for aggregation purposes only;

(c) include proved plus probable reserves, rather than proved reserves only under U.S. disclosure requirements. U.S. companies do not disclose probable reserves for non-mining properties. We voluntarily disclose our probable reserves for Firebag in-situ leases as we believe this information is useful to investors, and allows us to aggregate our mining and our in-situ reserves into a consolidated total for our oil sands business. As a result, our Firebag in-situ estimates in the above tables are not comparable to those made by U.S. companies.

(d) are evaluated based on 2007 Annual Average Differential Pricing assumptions, in accordance with CSA Staff Notice 51-315, versus Constant Cost and Pricing assumptions pursuant to U.S. disclosure requirements.

Remaining Recoverable Resources[1][2][3][4]

Suncor holds a 100% interest in its oil sands leases, all located near Fort McMurray in the Athabasca region of Alberta. Based upon independent evaluations conducted by GLJ effective December 31, 2007, our best estimate of remaining recoverable synthetic crude oil resources are as follows:



(1) As U.S. companies are prohibited from disclosing estimates of probable reserves for non-mining properties and resources for oil and gas or mining properties, Suncor's resource estimates will not be comparable to those made by U.S. companies.

(2) Remaining Recoverable Resources are the sum of reserves and contingent resources.

(3) 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.

(4) Best Estimate Resources is considered to be the best estimate of the quantity of resources 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.

The contingent resources are not classified as reserves due to the absence of a commercial development plan that includes a firm intent to develop within a reasonable timeframe, and in some cases due to higher uncertainty as a result of lower core-hole drilling density. Our Voyageur South development area, for which we submitted a regulatory application in 2007, is part of our mining contingent resources. Significant mining contingent resources are also associated with our Audet leases, located north of our Firebag leases and immediately adjacent to leases proposed for mining development by other operators. All of our in-situ leases are associated with our Firebag leases. While we consider the contingent resources to be potentially recoverable under reasonable economic and operating conditions, there is no certainty that it will be commercially viable to produce any portion of them.

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 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.

The ARO is measured at fair value every year-end, and incremental increases are discounted to present value using a credit-adjusted risk-free discount rate (2007 – 6.0%; 2006 – 5.5%). 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 and Comprehensive Income entitled "Accretion of asset retirement obligations". Payments to settle the obligations occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 30 years. 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 2007, we increased our estimated undiscounted total obligation to $2.231 billion from the previous estimate of $1.657 billion. The increase was primarily due to a change in the oil sands estimate to $1.941 billion from $1.473 billion, primarily reflecting increased estimated costs related to pond reclamation. The majority of the costs in oil sands are projected to occur over a time horizon extending to approximately 2060. In 2008, these changes in the ARO estimate are anticipated to result in additional after-tax expenses of approximately $24 million. The discounted amount of our ARO liability was $1.072 billion at December 31, 2007, compared to $808 million at December 31, 2006.

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 and Comprehensive Income. 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. The impact of a 1% change in the assumptions at which pension benefits and other post-retirement benefit liabilities could be effectively settled is disclosed in note 9 to the consolidated financial statements on page 75.

Property, Plant and Equipment

We account for our in-situ and natural gas exploration and production activities using the "successful efforts" method. This policy was selected over the alternative of the full-cost method because we believe it provides more timely 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 exploratory dry hole costs are written off and reported as part of exploration expenses in the Consolidated Statements of Earnings and Comprehensive Income. 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. Estimates of future cash flows are subject to significant management judgment concerning oil and gas prices, production quantities and operating 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 and Comprehensive Income.

Negative revisions in natural gas and in-situ reserves estimates will result in an increase in depletion expenses.

Control Environment

Based on their evaluation as of December 31, 2007, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures (as defined in Rules 13(a)-15(e) and 15(d)-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 under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. In addition, as of December 31, 2007, there were no changes in our internal control over financial reporting that occurred during 2007 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 as part of the reporting, certification and attestation requirements of Section 404 of the U.S. Sarbanes-Oxley Act of 2002. For the year ended December 31, 2007, the company's internal controls were found to be operating free of any material weaknesses.

CHANGE IN ACCOUNTING POLICIES

Financial Instruments

On January 1, 2007, the company adopted The Canadian Institute of Chartered Accountants (CICA) Handbook section 3855 "Financial Instruments, Recognition and Measurement", section 3865 "Hedging", section 1530 "Comprehensive Income" and section 3251 "Equity".

Sections 3855 and 3865 establish accounting and reporting standards for financial instruments and hedging activities, and require the initial recognition of financial instruments at fair value on the balance sheet. Section 1530 establishes standards for reporting and disclosure of comprehensive income, where comprehensive income refers to all changes in equity (net assets) during a reporting period except those resulting from investments by owners and distributions to owners, and section 3251 establishes standards for the presentation of equity and changes in equity during the reporting period.

The company's financial instruments consist of cash and cash equivalents, accounts receivable, derivative contracts, substantially all current liabilities (except for the current portions of asset retirement and pension obligations), and long-term debt. Unless otherwise noted, carrying values reflect the current fair value of the company's financial instruments.

The estimated fair values of financial instruments have been determined based on the company's assessment of available market information and/or appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction. Upon initial recognition, each financial asset and financial liability instrument is recorded at fair value, adjusted for any transaction costs.

Derivative contracts, excluding those considered as normal purchases and normal sales, are required to be recorded on the balance sheet at fair value. 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 each period. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income and are recognized in net earnings when the hedged item is recognized. 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.

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 hedge methodology. We do not recognize gains or losses arising from changes in the fair value of this debt until the gains or losses are realized.

The company's equity section will now contain a new caption "Accumulated Other Comprehensive Income". In addition to containing the effective portions of the gains/losses on our cash flow hedges, accumulated other comprehensive income will also contain the cumulative foreign currency translation adjustment of our foreign operations.

Upon implementation and initial measurement under the new standards at January 1, 2007, the following increases (decreases), net of income taxes, were recorded to the Consolidated Balance Sheet:

($ millions)	
Financial Assets (1)	42
Financial Liabilities (1)	29
Retained Earnings (2)	5
Cumulative Foreign Currency Translation (3)	71
Accumulated Other Comprehensive Loss (4)	(63)

(1) Recognition of fair value of derivative financial instruments designated as cash flow hedges and fair value hedges, and the related income tax impacts.

(2) Impact on adoption of the measurement of ineffectiveness on derivative financial instruments designated as cash flow hedges.

(3) Restatement of foreign currency translation adjustment to accumulated other comprehensive loss.

(4) Recognition of accumulated other comprehensive loss arising from the restatement of foreign currency translation adjustment, offset by accumulated other comprehensive income arising from the measurement of ineffectiveness on derivative financial instruments designated as cash flow hedges.

The comparative consolidated financial statements have not been restated, except for the presentation of the cumulative foreign currency translation adjustment.

RECENTLY ISSUED CANADIAN ACCOUNTING STANDARDS

Inventories

In June 2007, the CICA approved Handbook section 3031 "Inventories". Effective January 1, 2008, this standard eliminates the use of a LIFO (last-in-first-out) based valuation approach for inventory. The standard also requires any impairment to net realizable value of inventory to be written down at each reporting period, with subsequent reversals when applicable. This standard can be applied prospectively with an initial adjustment to retained earnings or applied retrospectively with restatement of comparative balances.

The company currently uses a LIFO methodology for crude oil and refined product inventory and will be transitioning to a FIFO (first-in-first-out) methodology beginning January 1, 2008. Retrospective application with restatement will increase the following financial statement balances upon transition:

($ millions)	
Inventory	404
Future Income Tax Liability	121
Retained Earnings	283

Capital Disclosures

In December 2006, the CICA approved Handbook section 1535 "Capital Disclosures". Effective January 1, 2008 this standard outlines required disclosure of specific information about an entity's objectives, policies and processes for managing capital. The new standard will not impact net earnings or financial position.

Financial Instruments

In December 2006, the CICA approved Handbook section 3862 "Financial Instruments Disclosure" and section 3863 "Financial Instruments Presentation". Effective January 1, 2008, these standards provide a complete set of disclosure and presentation requirements for financial instruments. The standards have increased emphasis on simplifying disclosures, while enhancing risk identification and discussion of how these risks are managed in relation to both recognized and unrecognized financial instruments. The new standard will not impact net earnings or financial position.

OIL SANDS

Located near Fort McMurray, Alberta, our oil sands business forms the foundation of our growth strategy and represents the most significant portion of our assets. The oil sands business recovers bitumen through mining and in-situ development and upgrades 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.

Oil sands strategy focuses on:

- Acquiring 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)	2007	2006	2005
Revenue	**6 775**	7 407	3 965
Production (thousands of bpd)	**235.6**	260.0	171.3
Average sales price ($/barrel)	**74.01**	68.03	53.81
Net earnings	**2 434**	2 783	957
Cash flow from operations [1]	**3 092**	3 917	1 916
Total assets	**18 108**	13 692	11 648
Cash used in investing activities	**4 248**	2 230	1 882
Net cash surplus (deficiency)	**(519)**	2 113	(236)
Sales mix (light/heavy mix)	**54/46**	53/47	54/46
Cash operating costs ($/barrel) [1]	**27.80**	21.70	24.55
ROCE (%) [2]	**42.6**	53.5	22.4
ROCE (%) [3]	**27.6**	40.1	16.0

(1) Non-GAAP measure. See page 46.

(2) 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. See Page 46.

(3) Includes capitalized costs related to major projects in progress. See page 46.

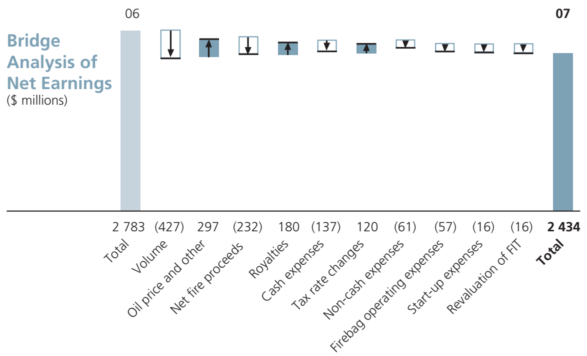
2007 Overview

- Oil sands production averaged 235,600 bpd in 2007, compared to 260,000 bpd in 2006. Production was down year-over-year primarily as the result of planned and unplanned maintenance including a planned 50-day outage of Upgrader 2.
- Oil sands cash operating costs averaged $27.80 per barrel during 2007, compared to $21.70 per barrel in 2006. The increase in 2007 was primarily due to fixed costs being spread over lower production, as well as higher maintenance costs related to planned and unplanned maintenance.

- The oil sands business made considerable progress on a variety of projects that are expected to benefit operational reliability, production and sales. At December 31, 2007, the addition of a new set of cokers to our upgrading complex was approximately 95% complete. This expansion is expected to increase production capacity to 350,000 bpd, with construction completion targeted in the second quarter of 2008 and ramp-up to full capacity expected in the fourth quarter. Other work included construction of a naphtha unit (which is intended to enhance product mix) which was approximately 20% complete at year-end, and the Steepbank extraction plant which was approximately 25% complete at year-end.
- Significant progress was also made on components of the Voyageur program to increase production capacity to 550,000 bpd in 2012. Engineering, procurement and field construction on these projects was advanced to a point sufficient for Suncor's Board of Directors to provide final project approval in early 2008.
- In July, Suncor filed a regulatory application for the Voyageur South mine extension. Bitumen produced at the proposed project is expected to provide additional feedstock flexibility.
- In August, Alberta Environment issued a new 10-year operating approval for Suncor's base oil sands operations.
- At our in-situ operation, high emissions resulted in intervention by both Alberta Environment and the Alberta Energy and Utilities Board. See page 25 for further discussion.

Analysis of Net Earnings

Net earnings were $2,434 million in 2007, compared to $2,783 million in 2006 (2005 – $957 million). Excluding the impacts of income tax rate revaluations, net insurance proceeds (relating to the January 2005 fire) and project start-up costs, earnings were $2,063 million in 2007, compared to $2,148 million in 2006 (2005 – $680 million).

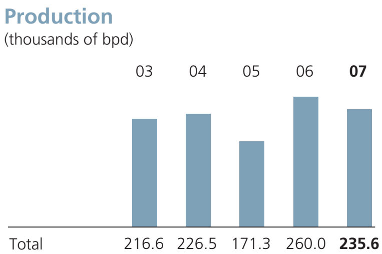


The decrease in earnings primarily reflects the impact of scheduled and unscheduled maintenance that reduced crude oil production and increased operating expenses.

Oil sands average production was 235,600 bpd in 2007, compared to 260,000 bpd in 2006. Sales volumes in 2007 averaged 234,700 bpd, compared with 263,100 bpd in 2006. Lower sales volumes decreased 2007 net earnings by $427 million. Production and sales volumes were significantly lower in 2007 due mainly to the planned shutdown of Upgrader 2 during the summer. The 50-day outage was required to tie-in new facilities related to our planned expansion of oil sands production capacity. Unplanned outages throughout the year have also had a negative impact on our 2007 production volumes.

Sales price realizations averaged $74.01 per barrel in 2007 (including the impact of pretax hedging losses of $5 million), compared with $68.03 per barrel in 2006 (with no pretax hedging gains). The average sales price realization was favourably impacted by stronger WTI benchmark crude oil prices and strengthening differentials on our sweet and sour crude blends relative to WTI, partially offset by a higher average US$/Cdn$ exchange rate. As crude oil is sold based on U.S. dollar benchmark prices, the increased average US$/Cdn$ exchange rate decreased the Canadian dollar value of crude oil products.

The net impact of the above sales mix and pricing factors increased net earnings by $297 million in 2007.



Cash Expenses

Cash expenses, which include purchases of crude oil and products, operating, selling and general expenses, transportation and other costs, exploration expenses, and taxes other than income taxes, were $2,833 million in 2007, compared to $2,546 million in 2006 (2005 – $1,652 million). Expenses increased year-over-year primarily due to higher maintenance expenditures, in addition to diesel fuel purchases made in order to satisfy customer commitments during the Upgrader 2 shutdown.

Overall, increased cash expenses, which include Firebag operating expenses, reduced net earnings by $194 million.

Royalties

Alberta oil sands Crown royalties decreased to $565 million in 2007, compared to $911 million in 2006 (2005 – $406 million). The lower royalty expense is due primarily to increased capital expenditures incurred, lower sales volumes and the absence of net insurance proceeds (relating to a January 2005 fire). These factors were partially offset by higher crude oil prices. Alberta oil sands Crown royalties are subject to completion of audits for 2007 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 page 19.

Non-Cash Expenses

Non-cash depreciation, depletion and amortization (DD&A) expense increased to $462 million from $385 million in 2006 (2005 – $330 million). The increase primarily resulted from continued growth in the depreciable cost base after the commissioning of new assets throughout the year. Higher non-cash expenses decreased net earnings by $61 million.

Revaluation of Future Income Taxes

Reductions to the federal income tax rate in the second and fourth quarters of 2007 resulted in a total decrease of $413 million in the oil sands opening future income tax (FIT) liability balance, and a corresponding increase in the net earnings of the oil sands segment. In the second quarter of 2006, reductions to both the federal and the Alberta provincial income tax rates resulted in a $429 million revaluation of the oil sands future income tax liability balance, with a corresponding increase in net earnings (2005 – nil).

Cash Operating Costs

Cash operating costs increased to $2,391 million in 2007, compared to $2,057 million in 2006. On a per barrel basis, these costs increased to $27.80 per barrel from $21.70 per barrel in 2006. The increase in cash operating costs per barrel is a result of increased operating expenses and lower production. Refer to page 46 for further details on cash operating costs as a non-GAAP financial measure, including the calculation and reconciliation to GAAP measures.

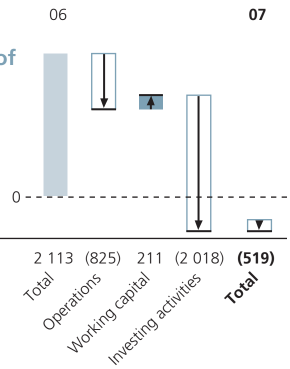
Net Cash Surplus (Deficiency) Analysis

Cash flow from operations was $3,092 million in 2007, compared to $3,917 million in 2006 (2005 – $1,916 million). The decrease was primarily due to the same factors that impacted net earnings, excluding the impact of depreciation, depletion and amortization. In addition, cash flows were reduced by cash income taxes that were not present in 2006.

Cash flow used in investing activities increased to $4,248 million in 2007 from $2,230 million in 2006 (2005 – $1,882 million). During 2007, capital spending related primarily to continued progress on the current coker unit expansion, future Voyageur strategy expansion, Steepbank extraction plant and naphtha unit projects.

Combined, the above factors resulted in a net cash deficiency of $519 million in 2007, compared with a surplus of $2,113 million in 2006 (2005 – $236 million deficiency).

Bridge Analysis of Net Cash Surplus
($ millions)



Future Expansion

In 2001, Suncor announced plans to pursue a multi-phased growth strategy to increase production capacity at its oil sands plant from 225,000 barrels per day (bpd) to 550,000 bpd in 2012.

The first step in that plan was completed in 2005 when Suncor increased production by 35,000 bpd (bringing the total production capacity to 260,000 bpd). In the second half of 2008, Suncor expects to complete an expansion to increase production capacity by 90,000 bpd (bringing the total production capacity to 350,000 bpd).

Suncor's Board of Directors approved the final phase of this multi-staged growth strategy in January 2008. An investment estimated at $20.6 billion for our Voyageur program is expected to increase production capacity by 200,000 bpd, enabling production capacity of 550,000 bpd in 2012. Of the $20.6 billion, $9 billion is planned for expansion of bitumen supply at our in-situ operation, while $11.6 billion is targeted for construction of a third upgrader. For further details, see the Significant Capital Projects table on page 18.

Risk Factors Affecting Performance

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

- Our ability to finance oil sands growth in a volatile commodity pricing environment. Also refer to Liquidity and Capital Resources on page 16.
- Our ability to complete future projects both on time and on budget. This could be impacted by competition from other projects (including other oil sands projects) for skilled people, increased demands on the Fort McMurray infrastructure (including housing, roads and schools), or higher prices for the products and services required to operate and maintain the operations. 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.
- 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.
- 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. These factors are difficult to predict and impossible to control.
- 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 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 2,100 oil sands employees. The current collective agreement with the union expires on April 30, 2010.

Additional risks, assumptions and uncertainties are discussed on page 48 under Forward-Looking Information. Also refer to Risk Factors Affecting Performance on page 21.

NATURAL GAS

Suncor's natural gas business, operating primarily in western Canada, acts as a price hedge against the company's purchases for internal consumption at our oil sands operations. This business also supports Suncor's sustainability goals by managing investment in wind energy projects and developing strategies to reduce greenhouse gas emissions.

Natural gas strategy focuses on:

- Building competitive operating areas.
- Improving base business efficiency, with a focus on operational excellence and work site safety.
- Developing new, low-capital business opportunities.

HIGHLIGHTS

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	**2007**	2006	2005
Revenue	**553**	578	679
Natural gas production (mmcf/d)	**196**	191	190
Average natural gas sales price ($/mcf)	**6.32**	7.15	8.57
Net earnings	**25**	106	155
Cash flow from operations [(1)]	**248**	281	412
Total assets	**1 811**	1 503	1 307
Cash used in investing activities	**532**	443	344
Net cash surplus (deficit)	**(262)**	(189)	63
ROCE (%) [(2)]	**2.5**	14.9	30.7

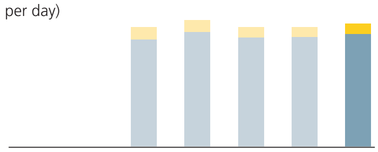
(1) Non-GAAP Measure. See Page 46.

(2) ROCE for Suncor operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non-GAAP Financial Measures. See page 46.

2007 Overview

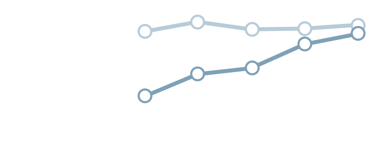
- Total production averaged 215 million cubic feet equivalent per day (mmcfe/d) in 2007, compared to 209 mmcfe/d in 2006. Production during 2007 was comprised of 91% natural gas and 9% natural gas liquids and crude oil.
- Company-wide purchases of natural gas for internal consumption were approximately 184 million cubic feet per day (mmcf/d) during 2007, compared to natural gas production of 196 mmcf/d in 2007.
- In September, Suncor commissioned its fourth wind power project. The 76-megawatt facility located near Ripley, Ontario is the company's largest wind power project.
- During the first quarter of 2007, Suncor acquired developed and undeveloped lands in British Columbia for approximately $160 million.

Total Production



(millions of cubic feet equivalent per day)	03	04	05	06	**07**
Natural gas liquids and crude oil	22	21	19	18	**19**
Natural gas	187	200	190	191	**196**
Total	209	221	209	209	**215**

Natural Gas Production vs. Purchases



(mmcf/d)	03	04	05	06	**07**
Production	187	200	190	191	**196**
Purchases	100	130	138	170	**184**

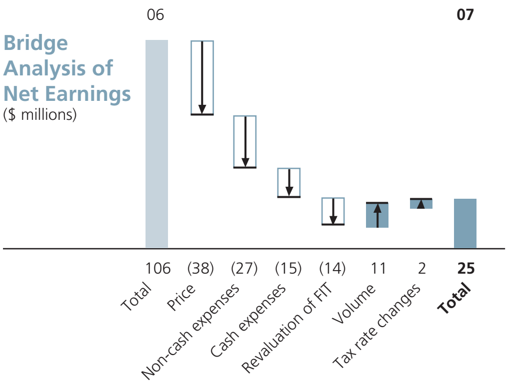
Analysis of Net Earnings

Natural gas net earnings were $25 million in 2007, compared to $106 million in 2006 (2005 – $155 million). Excluding the impact of income tax rate reductions on the opening future income tax liability, the net loss for 2007 was $14 million, compared to net earnings of $53 million in 2006 (2005 – $155 million). The decrease in net earnings was due primarily to lower natural gas price realizations and higher depreciation, depletion and amortization, operating costs, and transportation expenses.

The average realized price for natural gas was $6.32 per thousand cubic feet (mcf) in 2007, compared to an average of $7.15 per mcf in 2006, reflecting lower benchmark natural gas prices. This was partially offset by the increase in price realizations for crude oil and natural gas liquids that resulted from the higher benchmark prices for those products. The net impact of the price variance was a reduction in net earnings of $38 million.

Natural gas total production was 215 mmcfe/d in 2007, compared to 209 mmcfe/d in the prior year. The increase in 2007 production was primarily due to increased volumes from the Grizzly Valley area as a result of new wells added during the period and improved access to processing facilities. Increased production volumes positively impacted 2007 net earnings by $11 million.

Bridge Analysis of Net Earnings
($ millions)



Cash Expenses

Operating costs, including general and administrative expenses, were $135 million in 2007, compared to $110 million in 2006 (2005 – $93 million). The increase in operating costs was mainly due to higher lifting costs resulting from third-party processing fees and industry cost pressures, including higher labour costs.

Exploration expenses were $82 million in 2007, unchanged from 2006 (2005 – $46 million). A $15 million increase in dry hole costs recognized during the year was offset by a reduction in seismic expenditures.

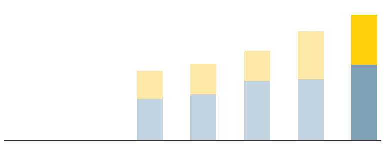
Non-Cash expenses

DD&A expense was $189 million in 2007, compared to $152 million in 2006 (2005 – $130 million). The increase was due to higher production and an increase in the capitalized costs, including the impact of developmental dry holes.

Royalties

Royalties on production of natural gas and liquids were $126 million ($1.61 per thousand cubic feet equivalent (mcfe)) in 2007, comparable to the $127 million royalty expense ($1.67 per mcfe) in 2006 (2005 – $149 million; $1.95 per mcfe). Higher production was offset by lower sales price realizations. In October 2007, the government of Alberta announced a new royalty framework which, if enacted by the government, will change royalty rates beginning in 2009. For a further discussion on Crown royalties, see page 20.

Lifting and Administration Costs
($/mcfe)

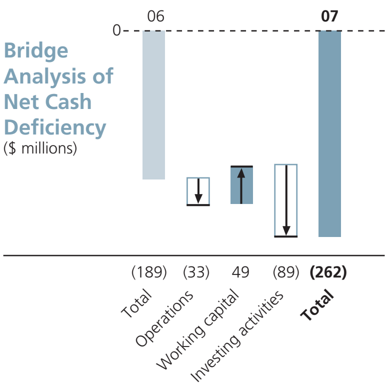


	03	04	05	06	**07**
Administration	0.39	0.43	0.42	0.67	**0.70**
Lifting	0.58	0.64	0.83	0.85	**1.05**
Total	0.97	1.07	1.25	1.52	**1.75**

Net Cash Deficiency Analysis

Natural gas net cash deficiency was $262 million in 2007, compared with a $189 million deficiency in 2006 (2005 – $63 million surplus). Cash flow from operations decreased to $248 million compared with $281 million in the prior year (2005 – $412 million), mainly due to decreased revenues and higher operating costs.

Cash used in investing activities increased to $532 million, compared with $443 million in 2006 (2005 – $344 million) primarily due to the acquisition of developed and undeveloped lands in British Columbia for approximately $160 million.



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.
- The impact of market demand for land. Market demand also influences the cost and available opportunities for acquisitions.
- The impact of market demand for labour and equipment, which in a heated exploration and development market, could increase costs and/or cause delays to projects for natural gas and its competitors.
- 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 reduced production.

Additional risks, assumptions and uncertainties are discussed on page 48 under Forward-Looking Information. Refer to Risk Factors Affecting Performance on page 21.

REFINING AND MARKETING

Consistent with the company's organizational restructuring during the first quarter of 2007, results from our Canadian and U.S. downstream marketing and refining operations have been combined into a single business segment – refining and marketing. Comparative figures have been reclassified to reflect the combination of the previously disclosed Energy Marketing & Refining – Canada (EM&R) and Refining & Marketing – U.S.A. (R&M) segments. There was no impact to previously reported net earnings as a result of the combination. The results of company-wide energy marketing and trading will continue to be included in this segment. The financial results relating to the sales of oil sands and natural gas production will continue to be reported in their respective business segments.

Refining and marketing operates a 70,000 barrel per day (bpd) capacity refinery in Sarnia, Ontario and a 90,000 bpd capacity refining complex in Commerce City, Colorado, and markets refined products to industrial, wholesale and commercial customers primarily in Ontario, Quebec and Colorado. Through a combination of joint venture-operated and company-owned retail stations, we market products to retail customers in Ontario and the Denver area. Assets also include a 200-million litre per year ethanol plant in St. Clair, Ontario, the 480-kilometre Rocky Mountain pipeline system, the 140-kilometre Centennial pipeline system, two product terminals in Ontario, and two product terminals in Grand Junction, Colorado.

The refining and marketing business also encompasses third-party energy marketing and trading activities, as well as providing marketing services for the sale of crude oil and natural gas from the oil sands and natural gas segments.

Refining and marketing's strategy is focused on:

- Enhancing the profitability of refining operations by improving reliability and 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.
- Reducing costs through the application of technologies, economies of scale, an increased focus on reliability through carefully managed maintenance scheduling, strategic alliances with key suppliers and customers and continuous improvement of operations.
- Increasing the profitability and efficiency of our retail networks.

HIGHLIGHTS

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	**2007**	2006	2005
Revenue	**11 173**	8 593	6 984
Refined product sales			
(millions of litres)			
Gasoline	**6 132**	5 804	5 585
Total	**12 228**	10 803	10 574
Net earnings breakdown:			
Total earnings excluding energy, marketing and trading activities	**335**	213	163
Energy marketing and trading activities	**10**	22	11
Total net earnings	**345**	235	174
Cash flow from operations (1)	**580**	443	363
Total assets	**4 519**	4 037	3 172
Cash used in investing activities	**(491)**	(787)	(818)
Net cash deficiency	**(29)**	(446)	(485)
ROCE (%) (2)	**16.8**	20.4	22.2
ROCE (%) (3)	**14.5**	12.5	13.8

(1) Non-GAAP measure. See page 46.

(2) 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. See page 46.

(3) Includes capitalized costs related to major projects in progress. See page 46.

2007 Overview

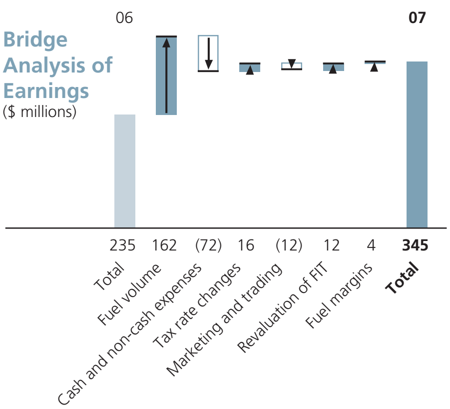
- The final phase of a three-year, $1 billion investment project in the Sarnia refinery is now complete. This investment was made to improve the refinery's environmental performance, enable the production of ultra low sulphur diesel fuel and increase the refinery's sour synthetic processing capacity. The upgrades to enable the production of ultra low sulphur diesel fuel were completed in 2006. The final phase of this multi-phased project was a 120-day shutdown of the refinery hydrocracker unit to complete the tie-in of new facilities to the existing refinery.
- During commissioning of the new facilities, operational difficulties were encountered resulting in a lengthier than planned start-up period. As a result, full production from the new facilities had not yet been achieved by year end.
- Refinery utilization levels increased as there were fewer scheduled shutdowns during 2007, compared to the prior year and the Commerce City refinery had improved reliability during the year.
- Both our Canadian and U.S. downstream operations benefited from high refining and retail margins due to tighter supply of refined products in the Ontario and U.S. Rocky Mountain markets during the first half of the year. Partially offsetting this was increased purchases of refined products to meet customer commitments during planned refinery shutdowns, which reduced overall fuel margins.

Analysis of Net Earnings

Refining and marketing results include the impact of our third-party energy marketing and trading activities that are discussed separately on page 43.

Refining and marketing's net earnings increased to $345 million in 2007 from $235 million in 2006 (2005 – $174 million). This increase was primarily due to higher sales volumes, offset by increased operating expenses.

Bridge Analysis of Earnings
($ millions)



Volumes

Total sales volumes averaged 33.5 $10^3m^3/d$ (thousands of cubic metres per day), compared to 29.5 $10^3m^3/d$ in 2006. The increase in sales was the result of the higher refinery utilization levels and higher purchases for resale. Total gasoline sales volumes through our Sunoco and Phillips 66® branded retail network were comparable to the prior year, with 1,900 million litres in 2007, slightly down from 1,935 million litres in 2006.

Fuel Margins

Refining and marketing benefited from stronger margins in both Canada and the U.S. Rocky Mountain regions during the first half of the year as tighter supply of refined products resulted in higher light oil product margins. This was mostly offset in the second half of the year by lower margins on heavy fuel oil sales and lower margins from finished products purchased for re-sale. Crude and product purchases were $6,351 million in 2007, compared to $5,308 million in 2006 (2005 – $4,613 million). The increase was a result of higher crude oil prices, higher crude oil purchases due to higher refinery utilization levels and an increase in refined product purchases to meet customer commitments during the planned outage at our Sarnia refinery.

Refinery Utilization

Overall crude refinery utilization averaged 98% in 2007, compared with 85% in 2006. The increase in refinery utilization was primarily the result of a reduction in overall planned maintenance shutdowns occurring during 2007 compared to 2006, in addition to improved reliability at the Commerce City refinery.

Cash and Non-Cash Expenses

Overall, cash and non-cash operating expenses increased by $72 million after-tax in 2007. Cash expenses increased by $44 million after-tax in 2007, primarily due to an increase in Canadian federal excise tax paid as a result of increased sales volumes in 2007. Non-cash expenses increased by $28 million after-tax in 2007, due to increased depreciation, depletion and amortization expense mainly resulting from a full year's depreciation being taken on the Commerce City and Sarnia refinery diesel desulphurization projects and the St. Clair ethanol project that were completed in 2006.

Related Party Transactions

The Pioneer and UPI retail facilities joint ventures and the Sun Petrochemicals Company (SPC) joint venture are considered to be related parties to Suncor under Canadian GAAP. Refining and marketing supplies refined petroleum products to the Pioneer and UPI joint ventures, and petrochemical products to SPC. Suncor has a separate supply agreement with each of Pioneer, UPI and SPC.

The following table summarizes our related party transactions with Pioneer, UPI and SPC, after eliminations, for the year. These transactions are in the normal course of operations and have been conducted on the same terms as would apply with third parties.

($ millions)	**2007**	2006	2005
Operating revenues			
Sales to refining and marketing joint ventures:			
Refined products	**329**	294	327
Petrochemicals	**163**	136	279

At December 31, 2007, amounts due from refining and marketing joint ventures were $17 million, compared to $20 million at December 31, 2006.

Energy Marketing and Trading Activities

Energy marketing and trading activities consist of both third party crude oil marketing and financial and physical derivatives trading activities. These activities resulted in net earnings after-tax of $10 million in 2007 compared to net earnings of $22 million in 2006 (2005 – $11 million). The higher earnings in 2006 compared to 2007 were the result of very strong crude trading margins in the prior year. For further details on our energy marketing and trading activities, see page 23.

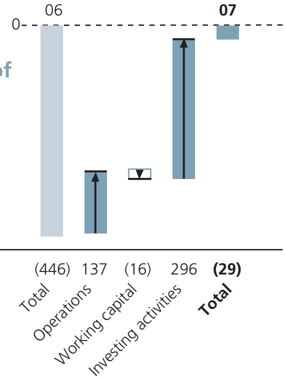
Energy trading activities, by their nature, can result in volatile and large positive or negative fluctuations in earnings. A separate risk management function reviews and monitors practices and policies and provides independent verification and valuation of these activities.

Net Cash Deficiency Analysis

Refining and marketing's net cash deficiency was $29 million in 2007 compared to a net cash deficiency of $446 million in 2006 (2005 – $485 million). Cash flow from operations was $580 million in 2007 compared to $443 million in 2006 (2005 – $363 million). The increase was primarily due to the same factors that impacted net earnings.

Cash used in investing activities was $491 million in 2007 compared to $787 million in 2006 (2005 – $818 million). Capital expenditures in 2007 were significantly lower than the previous year, as the majority of the work related to the diesel desulphurization and oil sands integration projects was completed in 2006. Capital spending in 2007 related mainly to completion of this work at Sarnia, including a planned refinery shutdown to allow the tie-in of the new facilities.

Bridge Analysis of Net Cash Surplus
($ 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.
- Environment Canada is expected to finalize regulations reducing sulphur in off-road diesel fuel and light fuel oil to take effect later in the decade. We believe that if the regulations are finalized as currently proposed, the new facilities for reducing sulphur in on-road diesel fuel should also allow the company to meet the requirements for reducing sulphur in off-road diesel and light fuel oil.

Additional risks, assumptions and uncertainties are discussed on page 48 under Forward-Looking Information. Refer to Risk Factors Affecting Performance on page 21.

OUTLOOK

During 2008, management will focus on the following priorities:

- **Achieve annual oil sands production of 275,000 to 300,000 bpd at a cash operating cost average of $25 to $27 per barrel.** Planned production increases with the commissioning of an expansion to Upgrader 2 and a strong focus on production reliability are key to managing operating costs.
- **Maintain production from our natural gas business (including natural gas liquids and crude oil) at an average 205 to 215 mmcf equivalent per day.** We expect to bring several new wells into production and will continue to focus on high-volume deep gas prospects in 2008.
- **Advance plans for increased bitumen supply.** Meet regulatory requirements to allow ramp up of expansion to Firebag Stages 1 and 2, commence construction of Stage 3 and seek regulatory approval to proceed with Stages 4 to 6. New third-party bitumen supplies are also expected in 2008.
- **Advance plans for increasing crude oil production.** Fully commission expanded units to enable production capacity of 350,000 bpd by year end. With Board of Director's approval given in January 2008, accelerate work on a $20.6 billion expansion of bitumen feed and upgrader capacity to generate 550,000 bpd capacity in 2012.
- **Fulfill regulatory requirements.** Construct and commission emission abatement equipment and reduce diluent discharges to the tailings ponds to meet specific regulatory requirements.
- **Continue to focus on safety.** Increase focus on identifying and reducing potential process hazards.
- **Focus on efficiency.** Safely complete planned modifications to Upgrader 2 aimed at ensuring reliable full capacity production. A planned maintenance shutdown to Upgrader 1, part of $1.5 billion in maintenance capital spending in 2008, is also expected to improve reliability going forward.
- **Maintain a strong balance sheet.** While net debt is expected to rise with capital spending of $7.5 billion in 2008, plan to maintain a strong debt to cash flow ratio and protect future cash flow with strategic crude oil hedging of up to 30% of planned production.
- **Continue efforts to reduce environmental impact intensity.** Investments planned to reduce sulphur emissions at oil sands facilities and reduce water use intensity.
- **Continue to pursue energy efficiencies, greenhouse gas offsets and new, renewable energy projects.** In oil sands operations, advance work on more efficient extraction technology. Advance renewable energy portfolio.

Suncor's outlook provides management's targets for 2008 in certain key areas of the company's business. Users of this information are cautioned that the actual events in 2008 may vary from the priorities disclosed.

	2008 Full-Year Outlook
Oil Sands	
Production	275,000 bpd to 300,000 bpd
Diesel	11%
Sweet	36%
Sour	49%
Bitumen	2%
Third-party processing	2%
Realization on crude sales basket	WTI @ Cushing less Cdn$4.25 to Cdn$5.25 per barrel
Cash operating costs (1)	$25.00 to $27.00 per barrel
Natural Gas	
Production (2) (mmcf equivalent per day)	205 to 215
Natural gas	93%
Liquids	7%

(1) Cash operating cost estimates are based on the following assumptions: i) production volumes and sales mix as described in the table above; and ii) a natural gas price of $6.70 per gigajoule at AECO. This goal also includes costs incurred for third-party bitumen processing. Cash operating costs per barrel are not prescribed by Canadian generally accepted accounting principles (GAAP). This non-GAAP financial measure does not have any standardized meaning and therefore is unlikely to be comparable to similar measures presented by other companies. Suncor includes this non-GAAP financial measure because investors may use this information to analyze operating performance. This information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. See Non-GAAP Financial Measures on page 46.

(2) Production target includes natural gas liquids (NGL) and crude oil converted into mmcf equivalent at a ratio of one barrel of NGL/crude oil: six thousand cubic feet of natural gas. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This mmcf equivalent may be misleading, particularly if used in isolation.

Factors that could potentially impact Suncor's 2008 financial performance include:

- **Planned maintenance at oil sands.** Upgrader 1 is expected to be shut down for approximately 30 days in the second quarter for scheduled maintenance. Although this shutdown is reflected in operational targets for the year, production estimates could be impacted if unplanned work is identified, or the schedule is impacted by labour or material supply issues. During the outage, Upgrader 2 is expected to continue producing approximately 200,000 bpd.
- **Completion and commissioning of an expansion to Upgrader 2 during the second quarter to enable production capacity of 350,000 bpd.** Production rates during the ramp-up period are difficult to predict and can be impacted by bitumen supply, as well as planned and unplanned maintenance. However, Suncor expects to move towards the 350,000 bpd capacity in the fourth quarter.
- **Regulatory requirements at the company's oil sands base plant and in-situ operation.** Suncor plans to incur maintenance and capital expenditures to construct and commission emission abatement equipment. The timing and scope of this work could impact 2008 results.
- **Bitumen supply.** If Suncor encounters unexpected issues in meeting regulatory requirements aimed at controlling emissions at both base plant and the in-situ operation, or if there are unexpected issues related to third-party supplies, there may be bitumen supply restrictions that could impact 2008 production targets.
- **Production volumes at the Sarnia refinery.** Suncor is lining-out new facilities at the refinery and this work could impact production in the first few months of 2008.
- **Crude oil hedges.** Consistent with the approval received from the Board of Directors, Suncor may fix a price or range of prices for up to approximately 30% of our planned production of crude oil for specified periods of time. At December 31, 2007, Suncor had hedging agreements in place for 10,000 bpd in 2008. These costless collar hedges have an average floor of US$59.85 per barrel with an average ceiling of US$101.06 per barrel in 2008.

For additional information on risk factors that could cause actual results to differ, please see page 21.

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.

Cash Flow from Operations per Common Share

Cash flow from operations is expressed before changes in non-cash working capital. A reconciliation of net earnings to cash flow from operations is provided in the Schedules of Segmented Data, which are an integral part of our Consolidated Financial Statements.

For the year ended December 31		**2007**	2006	2005
Cash flow from operations ($ millions)	A	**3 805**	4 533	2 476
Weighted average number of common shares outstanding – basic (millions of shares)	B	**461**	459	456
Cash flow from operations – basic ($ per share)	A/B	**8.25**	9.87	5.43

ROCE

For the year ended December 31 ($ millions, except ROCE)		**2007**	2006	2005
Adjusted net earnings				
Net earnings		**2 832**	2 971	1 158
Add: after-tax financing expenses (income)		**(179)**	26	(16)
	D	**2 653**	2 997	1 142
Capital employed – beginning of year				
Short-term and long-term debt, less cash and cash equivalents		**1 849**	2 868	2 134
Shareholders' equity		**8 952**	5 996	4 874
	E	**10 801**	8 864	7 008
Capital employed – end of year				
Short-term and long-term debt, less cash and cash equivalents		**3 248**	1 849	2 868
Shareholders' equity		**11 613**	8 952	5 996
	F	**14 861**	10 801	8 864
Average capital employed	(E+F)/2=G	**12 831**	9 832	7 936
Average capitalized costs related to major projects in progress	H	**3 454**	2 476	2 175
ROCE (%)	D/(G-H)	**28.3**	40.7	19.8

Oil Sands Operating Costs – Total Operations

(unaudited)		**2007 $ millions**	**2007 $/barrel**	2006 $ millions	2006 $/barrel	2005 $ millions	2005 $/barrel
Operating, selling and general expenses		**2 435**		2 198		1 455	
Less: natural gas costs, inventory changes and stock-based compensation		**(353)**		(361)		(281)	
Less: non-monetary transactions		**(102)**		(126)		—	
Accretion of asset retirement obligations		**41**		28		24	
Taxes other than income taxes		**55**		36		29	
Cash costs		**2 076**	**24.15**	1 775	18.70	1 227	19.60
Natural gas		**307**	**3.55**	276	2.90	307	4.90
Imported bitumen (net of other reported product purchases)		**8**	**0.10**	6	0.10	2	0.05
Cash operating costs	A	**2 391**	**27.80**	2 057	21.70	1 536	24.55
Project start-up costs	B	**60**	**0.95**	38	0.40	25	0.40
Total cash operating costs	A+B	**2 451**	**28.75**	2 095	22.10	1 561	24.95
Depreciation, depletion and amortization		**462**	**5.40**	385	4.05	330	5.30
Total operating costs		**2 913**	**34.15**	2 480	26.15	1 891	30.25
Production (thousands of barrels per day)		**235.6**		260.0		171.3	

Oil Sands Operating Costs – In-Situ Bitumen Production Only

(unaudited)		**2007 $ millions**	**2007 $/barrel**	2006 $ millions	2006 $/barrel	2005 $ millions	2005 $/barrel
Operating, selling and general expenses		**273**		209		155	
Less: natural gas costs and inventory changes		**(134)**		(103)		(91)	
Taxes other than income taxes		**7**		4		—	
Cash costs		**146**	**10.85**	110	8.95	64	9.15
Natural gas		**134**	**9.90**	103	8.35	91	13.05
Cash operating costs	A	**280**	**20.75**	213	17.30	155	22.20
In-situ (Firebag) start-up costs	B	**—**	**—**	21	1.70	7	1.00
Total cash operating costs	A+B	**280**	**20.75**	234	19.00	162	23.20
Depreciation, depletion and amortization		**83**	**6.20**	68	5.55	34	4.90
Total operating costs		**363**	**26.95**	302	24.55	196	28.10
Production (thousands of barrels per day)		**36.9**		33.7		19.1	

Legal Notice – Forward-Looking Information

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

All statements that address expectations or projections about the future, including statements about Suncor's strategy for growth, expected 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," "proposed," "target," "objective," and similar expressions. These statements are not guarantees of future performance and involve a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Suncor. Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements and readers are cautioned not to place undue reliance on them.

The risks, uncertainties and other factors that could influence actual results include, but are not limited to, 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 (for example, the Voyageur project, including our Firebag in-situ development) and regulatory projects (for example, the emissions reduction modifications at our Firebag in-situ development); 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 and 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 current 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; and 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. These foregoing important factors are not exhaustive.

Many of these risk factors are discussed in further detail throughout this Management's Discussion and Analysis and in the company'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 53 to 90 and all related financial information contained in this Annual Report, including Management's Discussion and Analysis.

We, as Suncor Energy Inc.'s Chief Executive Officer and Chief Financial Officer, have certified Suncor's annual disclosure document filed with the United States Securities and Exchange Commission (Form 40-F) as required by the United States Sarbanes-Oxley Act.

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 53 to 57. 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 all aspects of the company's operations.

The company retains independent petroleum consultants, GLJ Petroleum Consultants Ltd., 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 five 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

J. Kenneth Alley
Senior Vice President and
Chief Financial Officer

February 27, 2008

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. 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.
3. Management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2007, 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, 2007.
4. The effectiveness of the Company's internal control over financial reporting as of December 31, 2007 has been audited by PricewaterhouseCoopers LLP, independent auditors, as stated in their report which appears herein.

Richard L. George
President and
Chief Executive Officer

J. Kenneth Alley
Senior Vice President and
Chief Financial Officer

February 27, 2008

INDEPENDENT AUDITORS' REPORT

TO THE SHAREHOLDERS OF SUNCOR ENERGY INC.

We have completed integrated audits of the consolidated financial statements and internal control over financial reporting of Suncor Energy Inc. (the "Company") as of December 31, 2007 and 2006 and an audit of its 2005 consolidated financial statements. Our opinions, based on our audits, are presented below.

Consolidated financial statements

We have audited the accompanying consolidated balance sheets of Suncor Energy Inc. as at December 31, 2007 and December 31, 2006, and the related consolidated statements of earnings and comprehensive income, cash flows and shareholders' equity for each of the years in the three year period ended December 31, 2007. 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, 2007 and December 31, 2006 and for each of the years then ended in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). We conducted our audit of the Company's financial statements for the year ended December 31, 2005 in accordance with Canadian generally accepted auditing standards. 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, 2007 and December 31, 2006 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2007 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 of December 31, 2007, 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 effectiveness of 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.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007 based on criteria established in Internal Control – Integrated Framework issued by the COSO.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

February 27, 2008

COMMENTS BY AUDITORS FOR U.S. READERS ON CANADA – U.S. REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the company's financial statements, such as the changes described in note 1 to the consolidated financial statements. Our report to the shareholders dated February 27, 2008 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the Auditors' Report when the change is properly accounted for and adequately disclosed in the financial statements.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta, Canada

February 27, 2008

SUNCOR ENERGY INC.
SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Suncor Energy Inc. is a Canadian integrated energy company comprised of three operating segments: oil sands, natural gas, and refining and marketing.

Oil sands includes the production of light sweet and light sour crude oil, diesel fuel and various custom blends from oil sands in the Athabasca region of northeastern Alberta, and the marketing of these products substantially in Canada and the United States.

Natural gas includes the exploration, acquisition, development, production, transportation and marketing of natural gas and crude oil in Canada and the United States.

Refining and marketing includes the manufacturing, transportation and marketing of petroleum, petrochemical and biofuel products from our Canadian and United States operations. Canadian activities are conducted primarily in Ontario and Quebec, while activities in the United States are primarily in Colorado.

In addition to the operating segments outlined above, we also report a corporate segment which includes the activities not directly attributable to an operating segment, as well as those of our self-insurance entity.

The significant accounting policies of the company are summarized below:

(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 20.

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. 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.

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

(b) Cash Equivalents and Investments

Cash equivalents consist primarily of term deposits, certificates of deposit and all other highly liquid investments with a maturity at the time of purchase of three months or less. Investments with maturities greater than three months and up to one year are classified as short-term investments, while those with maturities in excess of one year are classified as long-term investments. Cash equivalents and short-term investments are stated at cost, which approximates market value.

(c) Revenues

Crude oil sales from upstream operations (oil sands and natural gas) to downstream operations (refining and marketing) are based on actual product shipments. On consolidation, revenues and purchases related to these sales transactions are eliminated from operating revenues and purchases of crude oil and products.

The company also uses its natural gas production for internal consumption at its oil sands plant and Sarnia refinery. On consolidation, revenues from these sales are eliminated from operating revenues, crude oil and products purchases, and operating, selling and general expenses.

Revenues associated with sales of crude oil, natural gas, petroleum and petrochemical products and all other items not eliminated on consolidation are recorded when title passes to the customer and delivery has taken place. Revenues from oil and natural gas production from properties in which the company has an interest with other producers are recognized on the basis of the company's net working interest.

(d) Property, Plant and Equipment

Cost

Property, plant and equipment are recorded at cost.

Expenditures to acquire and develop oil sands mining properties are capitalized. Development costs to expand the capacity of existing mines or to develop mine areas substantially in advance of current production are also capitalized. Drilling and related seismic costs for regulatory approved mining areas are capitalized when planned future development timelines do not exceed 10 years. All other mining exploration costs are expensed as incurred.

The company follows the successful efforts method of accounting for its conventional natural gas and in-situ oil sands operations. 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. Related land costs are expensed through the amortization of unproved properties as covered under the natural gas section of the depreciation, depletion and amortization policy below.

Development costs, which include the costs of wellhead equipment, development drilling costs, gas plants and handling facilities, applicable geological and geophysical costs 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.

Costs incurred after the inception of operations are expensed.

Interest Capitalization

Interest costs relating to major capital projects in progress and to the portion of non-producing oil and gas properties expected to become producing 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.

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

OIL SANDS Property, plant and equipment are depreciated over their useful lives on a straight-line basis, commencing when the assets are placed into service. Mine and mobile equipment is depreciated over periods ranging from three to 20 years and plant and other property and equipment, including leases in service, primarily over four to 40 years. Capitalized costs related to the in-progress phase of projects are not depreciated until the facilities are substantially complete and ready for their intended productive use.

NATURAL GAS Acquisition costs of unproved properties that are individually significant are evaluated for impairment by management. Impairment of unproved properties that are not individually significant is provided for through amortization over the average projected holding period for that portion of acquisition costs not expected to become producing. The average projected holding period of five years is based on historical experience.

Acquisition costs of proved properties are depleted using the unit of production method based on proved reserves. Capitalized exploratory drilling costs and development costs are depleted on the basis of proved developed reserves. For purposes of the depletion calculation, production and reserves volumes for oil and natural gas are converted to a common unit of measure on the basis of their approximate relative energy content. Gas plants, support facilities and equipment are depreciated on a straight-line basis over their useful lives, which average 12 years.

REFINING AND MARKETING Depreciation of property, plant and equipment is provided on a straight-line basis over the useful lives of assets. The Sarnia and Commerce City refineries and additions thereto are depreciated over an average of 30 years, service stations and related equipment over an average of 20 years and pipeline facilities and other equipment over three to 40 years.

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.

Impairment

Property, plant and equipment, including capitalized asset retirement costs, are reviewed for impairment whenever events or conditions indicate that their net carrying amount, less future income taxes, 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

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 are recognized in earnings for significant disposals or disposal of an entire property. However, the acquisition cost of a subsequently surrendered or abandoned unproved property that is not individually significant, or a partial abandonment of a proved property, is charged to accumulated depreciation, depletion and amortization.

(e) Deferred Charges and Other

The cost of major maintenance shutdowns is deferred and amortized on a straight-line basis over the period to the next shutdown, which varies from three to nine years. Normal maintenance and repair costs are charged to expense as incurred.

Deferred tax credits are government receivables, recognized when they are reasonably measurable and collectible, relating to eligible expenditures under various programs.

(f) 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.

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 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.

(g) Inventories

Inventories of crude oil and refined products are valued at the lower of cost (using the LIFO method) and net realizable value.

Materials and supplies are valued at the lower of average cost and net realizable value.

Costs include direct and indirect expenditures incurred in bringing an item or product to its existing condition and location.

See also Section (m) Recently Issued Canadian Accounting Standards.

(h) Financial Instruments

The company's financial instruments consist of cash and cash equivalents, accounts receivable, derivative contracts, substantially all current liabilities (except for the current portions of asset retirement and pension obligations), and long-term debt. Unless otherwise noted, carrying values reflect the current fair value of the company's financial instruments.

The estimated fair values of financial instruments have been determined based on the company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction. Each financial asset and financial liability instrument is initially measured at fair value, adjusted for any associated transaction costs.

The company periodically enters into derivative commodity contracts such as forwards, futures, swaps and options to hedge against the potential adverse impact of changing market prices due to changes in the underlying commodity indices. The company also periodically enters into derivative contracts such as interest rate swaps and foreign currency forwards as part of its risk management strategy to manage exposure to interest and foreign exchange rate fluctuations.

Derivative contracts, excluding those considered as normal purchases and normal sales, are required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge each period, 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 each period, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income and are recognized in net earnings when the hedged item is recognized. 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. The company uses these valuations to estimate the fair values of the underlying physical commodity contracts.

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 hedge methodology outlined 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.

See also Section (m) Recently Issued Canadian Accounting Standards.

(i) Foreign Currency Translation

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. 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.

United States operations of our refining and marketing business, 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 in the Consolidated Statements of Earnings and Comprehensive Income.

(j) Stock-Based Compensation Plans

Under the company's common share option programs (see note 12), common share options are granted to executives, employees and non-employee directors.

Compensation expense is recorded in the Consolidated Statements of Earnings and Comprehensive Income as operating, selling and general expense for all common share options granted to employees and non-employee directors on or after January 1, 2003, with a corresponding increase recorded as contributed surplus in the Consolidated Statements of Changes in Shareholders' Equity. 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 and Comprehensive Income over the estimated vesting periods of the respective options. 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.

For common share options granted prior to January 1, 2003 ("pre-2003 options"), compensation expense is not recognized in the Consolidated Statements of Earnings and Comprehensive Income. The company continues to disclose the pro forma earnings impact of related stock-based compensation expense for pre-2003 options. 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 are measured using the fair value based method of accounting. The expense is based on the fair values of the award at the time of grant and the change in fair value from the time of grant. The expense is recognized in the Consolidated Statements of Earnings and Comprehensive Income over the estimated vesting periods of the respective award.

(k) Transportation Costs

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

(l) 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 the 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.

(m) Recently Issued Canadian Accounting Standards

Inventories

In June 2007, the Canadian Institute of Chartered Accountants (CICA) approved Handbook section 3031 “Inventories”. Effective January 1, 2008 this standard eliminates the use of a LIFO (last-in-first-out) based valuation approach for inventory. The standard also requires any impairment to net realizable value of inventory to be written down at each reporting period, with subsequent reversals when applicable. This standard can be applied prospectively with an initial adjustment to retained earnings or applied retrospectively with restatement of comparative balances.

The company currently uses a LIFO methodology for crude oil and refined product inventory and will be transitioning to a FIFO (first-in-first-out) methodology beginning January 1, 2008. Retrospective application with restatement will increase the following financial statement balances upon transition:

Inventory	$404 million
Future Income Tax Liability	$121 million
Retained Earnings	$283 million

Going Concern

In June 2007, the CICA approved amendments to Handbook section 1400 “General Standards of Financial Statement Presentation”. The revisions, effective January 1, 2008, are to include specific requirements for assessing and disclosing an entity’s ability to continue as a going concern. The revised standard will not impact net earnings or financial position.

Capital Disclosures

In December 2006, the CICA approved Handbook section 1535 “Capital Disclosures”. Effective January 1, 2008 this standard outlines required disclosure of specific information about an entity’s objectives, policies and processes for managing capital. The new standard will not impact net earnings or financial position.

Financial Instruments

In December 2006, the CICA approved Handbook section 3862 “Financial Instruments Disclosure” and section 3863 “Financial Instruments Presentation”. Effective January 1, 2008, these standards provide a complete set of disclosure and presentation requirements for financial instruments. The standards have increased emphasis on making disclosures more transparent, while enhancing risk identification and discussion of how these risks are managed in relation to both recognized and unrecognized financial instruments. The new standard will not impact net earnings or financial position.

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

For the years ended December 31 ($ millions)	**2007**	2006 (restated) (note 1)	2005 (restated) (note 1)
Revenues			
Operating revenues (notes 7, 17 and 19)	**15 020**	13 798	9 728
Energy marketing and trading activities (note 7c)	**2 883**	1 582	827
Net insurance proceeds	**—**	436	572
Interest	**30**	13	2
	17 933	15 829	11 129
Expenses			
Purchases of crude oil and products	**5 935**	4 678	4 164
Operating, selling and general	**3 375**	3 043	2 437
Energy marketing and trading activities (note 7c)	**2 870**	1 541	789
Transportation and other costs	**198**	212	152
Depreciation, depletion and amortization	**864**	695	568
Accretion of asset retirement obligations	**48**	34	30
Exploration (note 19)	**95**	104	56
Royalties (note 5)	**691**	1 038	555
Taxes other than income taxes (note 19)	**648**	595	529
Loss (gain) on disposal of assets	**7**	(1)	(13)
Project start-up costs	**68**	45	25
Financing expenses (income) (note 15)	**(211)**	39	(15)
	14 588	12 023	9 277
Earnings Before Income Taxes	**3 345**	3 806	1 852
Provision for income taxes (note 10)			
Current	**382**	20	39
Future	**131**	815	655
	513	835	694
Net Earnings	**2 832**	2 971	1 158
Other comprehensive income (loss) (notes 1, 7 and 18)	**(190)**	10	(26)
Comprehensive Income	**2 642**	2 981	1 132
Net Earnings Per Common Share (dollars) (note 13)			
Net earnings attributable to common shareholders			
Basic	**6.14**	6.47	2.54
Diluted	**6.02**	6.32	2.48
Cash dividends	**0.38**	0.30	0.24

See accompanying Summary of Significant Accounting Policies and Notes.

CONSOLIDATED BALANCE SHEETS

As at December 31 ($ millions)	2007	2006 (restated) (note 1)
Assets		
Current assets		
Cash and cash equivalents	**569**	521
Accounts receivable (notes 1, 7, 11 and 19)	**1 416**	1 050
Inventories (note 16)	**608**	589
Income taxes receivable	**95**	33
Future income taxes (note 10)	**130**	109
Total current assets	**2 818**	2 302
Property, plant and equipment, net (note 3)	**20 945**	16 160
Deferred charges and other (note 4)	**404**	297
Total assets	**24 167**	18 759
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**6**	7
Accounts payable and accrued liabilities (notes 1, 7, 8 and 9)	**2 775**	2 111
Taxes other than income taxes	**72**	40
Income taxes payable	**244**	—
Total current liabilities	**3 097**	2 158
Long-term debt (note 6)	**3 811**	2 363
Accrued liabilities and other (notes 8 and 9)	**1 434**	1 214
Future income taxes (note 10)	**4 212**	4 072
Total liabilities	**12 554**	9 807
Commitments and contingencies (note 11)		
Shareholders' equity		
Share capital (note 12)	**881**	794
Contributed surplus (note 12)	**194**	100
Accumulated other comprehensive income (loss) (notes 1, 7 and 18)	**(253)**	(71)
Retained earnings (note 1)	**10 791**	8 129
Total shareholders' equity	**11 613**	8 952
Total liabilities and shareholders' equity	**24 167**	18 759

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 27, 2008

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ millions)	**2007**	2006	2005
Operating Activities			
Cash flow from operations [a]	**3 805**	4 533	2 476
Decrease (increase) in operating working capital			
Accounts receivable	**(365)**	53	(477)
Inventories	**(19)**	(66)	(63)
Accounts payable and accrued liabilities	**226**	87	435
Taxes payable/receivable	**246**	(43)	(23)
Cash flow from operating activities	**3 893**	4 564	2 348
Cash Used in Investing Activities [a]	**(5 362)**	(3 489)	(3 113)
Net Cash Surplus (Deficiency) Before Financing Activities	**(1 469)**	1 075	(765)
Financing Activities			
Increase (decrease) in short-term debt	**(4)**	(42)	19
Net proceeds from issuance of long-term debt	**1 835**	—	—
Net increase (decrease) in long-term debt	**(171)**	(622)	808
Issuance of common shares under stock option plans	**62**	45	69
Dividends paid on common shares	**(162)**	(127)	(102)
Deferred revenue	**4**	27	50
Cash flow provided by (used in) financing activities	**1 564**	(719)	844
Increase in Cash and Cash Equivalents	**95**	356	79
Effect of Foreign Exchange on Cash and Cash Equivalents	**(47)**	—	(2)
Cash and Cash Equivalents at Beginning of Year	**521**	165	88
Cash and Cash Equivalents at End of Year	**569**	521	165

(a) See Schedules of Segmented Data on pages 63 and 64.

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	Cumulative Foreign Currency Translation	Retained Earnings	Accumulated Other Comprehensive Income (AOCI)
At December 31, 2004, as previously reported	651	32	(55)	4 246	—
Retroactive adjustment for change in accounting policy, net of tax (note 1)	—	—	55	—	(55)
At December 31, 2004, as restated	651	32	—	4 246	(55)
Net earnings	—	—	—	1 158	—
Dividends paid on common shares	—	—	—	(102)	—
Issued for cash under stock option plans	74	(5)	—	—	—
Issued under dividend reinvestment plan	7	—	—	(7)	—
Stock-based compensation expense	—	23	—	—	—
Change in AOCI related to foreign currency translation	—	—	—	—	(26)
At December 31, 2005, as restated	732	50	—	5 295	(81)
Net earnings	—	—	—	2 971	—
Dividends paid on common shares	—	—	—	(127)	—
Issued for cash under stock option plans	52	(7)	—	—	—
Issued under dividend reinvestment plan	10	—	—	(10)	—
Stock-based compensation expense	—	53	—	—	—
Income tax benefit of stock option deductions in the U.S.	—	4	—	—	—
Change in AOCI related to foreign currency translation	—	—	—	—	10
At December 31, 2006, as restated	794	100	—	8 129	(71)
Net earnings	**—**	**—**	**—**	**2 832**	**—**
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 AOCI related to foreign currency translation	**—**	**—**	**—**	**—**	**(195)**
Change in AOCI related to derivative hedging activities	**—**	**—**	**—**	**—**	**5**
At December 31, 2007	**881**	**194**	**—**	**10 791**	**(253)**

See accompanying Summary of Significant Accounting Policies and Notes.

SCHEDULES OF SEGMENTED DATA [a]

For the years ended December 31 ($ millions)	Oil Sands **2007**	2006	2005	Natural Gas **2007**	2006	2005	Refining and Marketing (note 2) **2007**	2006	2005
EARNINGS									
Revenues [b]									
Operating revenues	**6 195**	6 259	2 938	**541**	554	632	**8 278**	6 981	6 155
Energy marketing and trading activities	**—**	—	—	**—**	—	—	**2 890**	1 607	827
Net insurance proceeds	**—**	436	572	**—**	—	—	**—**	—	—
Intersegment revenues [c]	**580**	712	455	**12**	23	47	**—**	—	—
Interest	**—**	—	—	**—**	1	—	**5**	5	2
	6 775	7 407	3 965	**553**	578	679	**11 173**	8 593	6 984
Expenses									
Purchases of crude oil and products	**157**	89	32	**—**	—	—	**6 351**	5 308	4 613
Operating, selling and general (note 2)	**2 435**	2 198	1 455	**135**	110	93	**693**	669	682
Energy marketing and trading activities	**—**	—	—	**—**	—	—	**2 876**	1 572	810
Transportation and other costs	**138**	162	104	**31**	25	22	**29**	25	26
Depreciation, depletion and amortization	**462**	385	330	**189**	152	130	**171**	132	96
Accretion of asset retirement obligations	**40**	28	24	**7**	5	5	**1**	1	1
Exploration	**13**	22	10	**82**	82	46	**—**	—	—
Royalties (note 5)	**565**	911	406	**126**	127	149	**—**	—	—
Taxes other than income taxes	**90**	75	51	**4**	3	3	**553**	516	475
Loss (gain) on disposal of assets	**1**	—	—	**(1)**	(4)	(12)	**7**	3	(1)
Project start-up costs	**60**	38	25	**—**	—	—	**8**	7	—
Financing expenses (income)	**—**	—	—	**—**	—	—	**—**	—	—
	3 961	3 908	2 437	**573**	500	436	**10 689**	8 233	6 702
Earnings (loss) before income taxes	**2 814**	3 499	1 528	**(20)**	78	243	**484**	360	282
Income taxes	**(380)**	(716)	(571)	**45**	28	(88)	**(139)**	(125)	(108)
Net earnings (loss)	**2 434**	2 783	957	**25**	106	155	**345**	235	174
As at December 31									
TOTAL ASSETS	**18 108**	13 692	11 648	**1 811**	1 503	1 307	**4 519**	4 037	3 172

(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 2007, 2006 or 2005 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.

SCHEDULES OF SEGMENTED DATA[a] (continued)

For the years ended December 31 ($ millions)	Corporate and Eliminations			Total		
	2007	2006	2005	**2007**	2006	2005
EARNINGS						
Revenues[b]						
Operating revenues	**6**	4	3	**15 020**	13 798	9 728
Energy marketing and trading activities	**(7)**	(25)	—	**2 883**	1 582	827
Net insurance proceeds	**—**	—	—	**—**	436	572
Intersegment revenues[c]	**(592)**	(735)	(502)	**—**	—	—
Interest	**25**	7	—	**30**	13	2
	(568)	(749)	(499)	**17 933**	15 829	11 129
Expenses						
Purchases of crude oil and products	**(573)**	(719)	(481)	**5 935**	4 678	4 164
Operating, selling and general (note 2)	**112**	66	207	**3 375**	3 043	2 437
Energy marketing and trading activities	**(6)**	(31)	(21)	**2 870**	1 541	789
Transportation and other costs	**—**	—	—	**198**	212	152
Depreciation, depletion and amortization	**42**	26	12	**864**	695	568
Accretion of asset retirement obligations	**—**	—	—	**48**	34	30
Exploration	**—**	—	—	**95**	104	56
Royalties (note 5)	**—**	—	—	**691**	1 038	555
Taxes other than income taxes	**1**	1	—	**648**	595	529
Loss (gain) on disposal of assets	**—**	—	—	**7**	(1)	(13)
Project start-up costs	**—**	—	—	**68**	45	25
Financing expenses (income)	**(211)**	39	(15)	**(211)**	39	(15)
	(635)	(618)	(298)	**14 588**	12 023	9 277
Earnings (loss) before income taxes	**67**	(131)	(201)	**3 345**	3 806	1 852
Income taxes	**(39)**	(22)	73	**(513)**	(835)	(694)
Net earnings (loss)	**28**	(153)	(128)	**2 832**	2 971	1 158
As at December 31						
TOTAL ASSETS	**(271)**	(473)	(1 001)	**24 167**	18 759	15 126

SCHEDULES OF SEGMENTED DATA[a] (continued)

For the years ended December 31 ($ millions)	Oil Sands 2007	Oil Sands 2006	Oil Sands 2005	Natural Gas 2007	Natural Gas 2006	Natural Gas 2005	Refining and Marketing (note 2) 2007	Refining and Marketing (note 2) 2006	Refining and Marketing (note 2) 2005
CASH FLOW BEFORE FINANCING ACTIVITIES									
Cash from (used in) operating activities:									
Cash flow from (used in) operations									
Net earnings (loss)	**2 434**	2 783	957	**25**	106	155	**345**	235	174
Exploration expenses	**—**	—	—	**67**	52	46	**—**	—	—
Non-cash items included in earnings									
Depreciation, depletion and amortization	**462**	385	330	**189**	152	130	**171**	132	96
Future income taxes	**97**	731	609	**(43)**	(28)	88	**40**	70	72
Loss (gain) on disposal of assets	**1**	—	—	**(1)**	(4)	(12)	**7**	3	(1)
Stock-based compensation expense	**49**	25	11	**5**	2	—	**25**	13	6
Other	**1**	14	23	**7**	1	5	**(5)**	(7)	16
Increase (decrease) in deferred credits and other	**48**	(21)	(14)	**(1)**	—	—	**(3)**	(3)	—
Total cash flow from (used in) operations	**3 092**	3 917	1 916	**248**	281	412	**580**	443	363
Decrease (increase) in operating working capital	**637**	426	(270)	**22**	(27)	(5)	**(118)**	(102)	(30)
Total cash from (used in) operating activities	**3 729**	4 343	1 646	**270**	254	407	**462**	341	333
Cash from (used in) investing activities:									
Capital and exploration expenditures	**(4 431)**	(2 463)	(1 948)	**(531)**	(458)	(363)	**(376)**	(665)	(779)
Acquisition of Denver refineries and related assets	**—**	—	—	**—**	—	—	**—**	—	(62)
Deferred maintenance shutdown expenditures	**(135)**	—	(65)	**(6)**	—	(2)	**(73)**	(80)	(10)
Deferred outlays and other investments	**(18)**	(2)	(1)	**—**	—	—	**—**	7	4
Proceeds from disposals	**3**	2	41	**5**	15	21	**1**	4	3
Proceeds from property loss	**—**	36	44	**—**	—	—	**—**	—	—
Decrease (increase) in investing working capital	**333**	197	47	**—**	—	—	**(43)**	(53)	26
Total cash (used in) investing activities	**(4 248)**	(2 230)	(1 882)	**(532)**	(443)	(344)	**(491)**	(787)	(818)
Net cash surplus (deficiency) before financing activities	**(519)**	2 113	(236)	**(262)**	(189)	63	**(29)**	(446)	(485)

(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.

SCHEDULES OF SEGMENTED DATA[a] (continued)

For the years ended December 31 ($ millions)	Corporate and Eliminations **2007**	2006	2005	Total **2007**	2006	2005
CASH FLOW BEFORE FINANCING ACTIVITIES						
Cash from (used in) operating activities:						
Cash flow from (used in) operations						
Net earnings (loss)	**28**	(153)	(128)	**2 832**	2 971	1 158
Exploration expenses	**—**	—	—	**67**	52	46
Non-cash items included in earnings						
Depreciation, depletion and amortization	**42**	26	12	**864**	695	568
Future income taxes	**37**	42	(114)	**131**	815	655
Loss (gain) on disposal of assets	**—**	—	—	**7**	(1)	(13)
Stock-based compensation expense	**24**	13	6	**103**	53	23
Other	**(236)**	(22)	(77)	**(233)**	(14)	(33)
Increase (decrease) in deferred credits and other	**(10)**	(14)	86	**34**	(38)	72
Total cash flow from (used in) operations	**(115)**	(108)	(215)	**3 805**	4 533	2 476
Decrease (increase) in operating working capital	**(453)**	(266)	177	**88**	31	(128)
Total cash from (used in) operating activities	**(568)**	(374)	(38)	**3 893**	4 564	2 348
Cash from (used in) investing activities:						
Capital and exploration expenditures	**(77)**	(27)	(63)	**(5 415)**	(3 613)	(3 153)
Acquisition of Denver refineries and related assets	**—**	—	—	**—**	—	(62)
Deferred maintenance shutdown expenditures	**—**	—	—	**(214)**	(80)	(77)
Deferred outlays and other investments	**(14)**	(2)	(6)	**(32)**	3	(3)
Proceeds from disposals	**—**	—	—	**9**	21	65
Proceeds from property loss	**—**	—	—	**—**	36	44
Decrease (increase) in investing working capital	**—**	—	—	**290**	144	73
Total cash (used in) investing activities	**(91)**	(29)	(69)	**(5 362)**	(3 489)	(3 113)
Net cash surplus (deficiency) before financing activities	**(659)**	(403)	(107)	**(1 469)**	1 075	(765)

SUNCOR ENERGY INC.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. CHANGES IN ACCOUNTING POLICIES

Financial Instruments

On January 1, 2007 the company adopted CICA Handbook Section 3855 "Financial Instruments, Recognition and Measurement", Section 3865 "Hedging", Section 1530 "Comprehensive Income" and Section 3251 "Equity".

Sections 3855 and 3865 establish accounting and reporting standards for financial instruments and hedging activities, and require the initial recognition of financial instruments at fair value on the balance sheet. Section 1530 establishes standards for reporting and display of comprehensive income, where comprehensive income refers to all changes in equity (net assets) during a reporting period except those resulting from investments by owners and distributions to owners, and Section 3251 establishes standards for the presentation of equity and changes in equity during the reporting period.

The company's financial instruments consist of cash and cash equivalents, accounts receivable, derivative contracts, substantially all current liabilities (except for the current portions of asset retirement and pension obligations), and long-term debt. Unless otherwise noted, carrying values reflect the current fair value of the company's financial instruments.

The estimated fair values of financial instruments have been determined based on the company's assessment of available market information and/or appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction. Upon initial recognition, each financial asset and financial liability instrument is recorded at fair value, adjusted for any transaction costs.

Derivative contracts, excluding those considered as normal purchases and normal sales, are required to be recorded on the balance sheet at fair value. 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 each period. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income and are recognized in net earnings when the hedged item is recognized. 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.

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 hedge methodology. We do not recognize gains or losses arising from changes in the fair value of this debt until the gains or losses are realized.

The company's equity section now contains a new caption "Accumulated Other Comprehensive Income". In addition to containing the effective portions of the gains/losses on our cash flow hedges, accumulated other comprehensive income will also contain the cumulative foreign currency translation adjustment of our self-sustaining foreign operations.

Upon implementation and initial measurement under the new standards at January 1, 2007, the following increases (decreases), net of income taxes, were recorded to the Consolidated Balance Sheet:

($ millions)	
Financial Assets (1)	42
Financial Liabilities (1)	29
Retained Earnings (2)	5
Cumulative Foreign Currency Translation (3)	71
Accumulated Other Comprehensive Loss (4)	(63)

(1) Recognition of fair value of derivative financial instruments designated as cash flow hedges and fair value hedges, and the related income tax impacts
(2) Impact on adoption of the measurement of ineffectiveness on derivative financial instruments designated as cash flow hedges
(3) Restatement of foreign currency translation adjustment to accumulated other comprehensive loss
(4) Recognition of accumulated other comprehensive loss arising from the restatement of foreign currency translation adjustment, offset by accumulated other comprehensive income arising from the effective component on derivative financial instruments designated as cash flow hedges

The comparative consolidated financial statements have not been restated, except for the presentation of the cumulative foreign currency translation adjustment.

See Note 7 for a summary of financial instrument disclosures at December 31, 2007.

2. CHANGE IN SEGMENTED DISCLOSURES

Consistent with the company's organizational restructuring during the first quarter of 2007, results from our Canadian and U.S. downstream refining and marketing operations have been combined into a single business segment – refining and marketing. Comparative figures have been reclassified to reflect the combination of the previously disclosed Energy Marketing & Refining – Canada (EM&R) and Refining & Marketing – U.S.A. (R&M) segments. The results of company-wide energy marketing and trading activities will continue to be included in this segment. The financial results relating to the sales of oil sands and natural gas production will continue to be reported in their respective business segments. There was no impact to consolidated net earnings as a result of the restructuring.

Effective January 1, 2007, the company began allocating stock-based compensation expense to each of the reportable business segments. Comparative figures have been reclassified to reflect the allocation of stock-based compensation. There was no impact to consolidated net earnings as a result of the allocation.

3. PROPERTY, PLANT AND EQUIPMENT

	2007		2006	
($ millions)	Cost	Accumulated Provision	Cost	Accumulated Provision
Oil sands				
Plant	**11 049**	**1 962**	8 160	1 706
Mine and mobile equipment	**1 423**	**388**	1 191	320
In-situ properties	**2 566**	**222**	1 963	148
Pipeline	**149**	**35**	149	29
Capital leases	**102**	**6**	38	4
Major projects in progress	**3 830**	**—**	2 887	—
	19 119	**2 613**	14 388	2 207
Natural gas				
Proved properties	**2 405**	**1 042**	1 975	874
Unproved properties	**238**	**32**	186	21
Other support facilities and equipment	**92**	**30**	90	23
	2 735	**1 104**	2 251	918
Refining and marketing				
Refinery	**2 699**	**628**	2 179	555
Marketing	**783**	**304**	741	291
Pipeline	**53**	**4**	35	3
Major projects in progress	**—**	**—**	386	—
	3 535	**936**	3 341	849
Corporate	**305**	**96**	208	54
	25 694	**4 749**	20 188	4 028
Net property, plant and equipment		**20 945**		16 160

4. DEFERRED CHARGES AND OTHER

($ millions)	**2007**	2006
Deferred maintenance shutdown costs	**296**	172
Deferred government tax credits	**36**	74
Other	**72**	51
Total deferred charges and other	**404**	297

5. ROYALTIES

Our current estimation of Alberta Crown royalties is based on regulations currently in effect. Alberta Crown royalties currently in effect for each oil sands project require payments to the Government of Alberta based on annual gross revenues less related transportation costs (R) less allowable costs (C), including the deduction of certain capital expenditures (the 25% R-C royalty), subject to a minimum payment of 1% of R. Royalty expense for the company's oil sands operations for the year ended December 31, 2007, was $565 million (2006 – $911 million, 2005 – $406 million). The balance of the consolidated royalty expense is in respect of natural gas royalties of $126 million (2006 – $127 million, 2005 – $149 million).

The regime changes proposed by the Government of Alberta will increase royalty rates, effective January 1, 2009 to a sliding scale of 25% – 40% of R-C, subject to a minimum royalty of 1% – 9% depending on oil price. In both cases, the sliding scale royalty would move with increases in WTI prices from Cdn$55 to the maximum rates at a WTI price of Cdn$120.

In January 2008, Suncor entered into a Royalty Amending Agreement with the government of Alberta to transition to the new royalty framework rates in the Generic Regime commencing January 1, 2010 to January 1, 2016. The new royalty framework rates will apply to the bitumen royalty for current production levels of our base oil sands mining operations, subject to a cap of 30% of R-C, and a minimum royalty of 1.2% of R (assuming the government enacts their proposed framework). In addition, the Suncor Royalty Amending agreement provides Suncor with 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 (our base operation and Firebag in-situ project) will be the rates prescribed under the generic regime.

6. LONG-TERM DEBT

A. Fixed-term debt, redeemable at the option of the company

($ millions)	**2007**	2006
6.50% Notes, denominated in U.S. dollars, due in 2038 (US$1150) (i)	**1 137**	—
5.95% Notes, denominated in U.S. dollars, due in 2034 (US$500)	**494**	583
7.15% Notes, denominated in U.S. dollars, due in 2032 (US$500)	**494**	583
5.39% Series 4 Medium Term Notes, due in 2037 (ii)	**600**	—
6.70% Series 2 Medium Term Notes, due in 2011 (iii)	**500**	500
6.80% Medium Term Notes, repaid in 2007 (iii) (iv)	**—**	250
6.10% Medium Term Notes, repaid in 2007 (iii) (iv)	**—**	150
	3 225	2 066
Revolving-term debt, with interest at variable rates (see B. Credit Facilities)		
Commercial Paper (interest at December 31, 2007 – 4.8%, 2006 – 4.3%) (v)	**522**	280
Total unsecured long-term debt	**3 747**	2 346
Secured long-term debt	**1**	1
Capital leases (vi), (vii)	**102**	38
Fair values of interest swaps	**6**	—
Deferred financing costs	**(45)**	(22)
Total long-term debt	**3 811**	2 363

(i) During the third quarter of 2007, the company issued additional 6.50% Notes with a principal amount of US$400 million under an outstanding US$2 billion debt shelf prospectus. These notes bear interest, which is paid semi-annually, and mature on June 15, 2038. The net proceeds were used for general corporate purposes, including reducing short-term borrowings, supporting our ongoing capital spending program and for working capital requirements.

During the second quarter of 2007, the company issued 6.50% Notes with a principal amount of US$750 million under an outstanding US$2 billion debt shelf prospectus. These notes bear interest, which is paid semi-annually, and mature on June 15, 2038. The net proceeds were used for general corporate purposes, including reducing short-term borrowings, supporting our ongoing capital spending program and for working capital requirements.

(ii) During the first quarter of 2007, the company issued 5.39% Medium Term Notes with a principal amount of $600 million under an outstanding $2 billion debt shelf prospectus. These notes bear interest, which is paid semi-annually, and mature on March 26, 2037. The net proceeds were used for general corporate purposes, including reducing short-term borrowings, supporting our ongoing capital spending program and for working capital requirements.

(iii) The company has entered into various 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 2007	Effective Interest Rate 2006
Swap of 6.70% Medium Term Notes to floating rates	200	2011	5.7%	5.2%
Swap of 6.80% Medium Term Notes to floating rates (iv)	250	2007	6.0%	6.0%
Swap of 6.10% Medium Term Notes to floating rates (iv)	150	2007	4.7%	5.3%

(iv) During the third quarter of 2007, the company repaid maturing 6.10% $150 million Medium Term Notes using commercial paper, and the associated swap transaction expired.

During the first quarter of 2007, the company repaid maturing 6.80% $250 million Medium Term Notes using commercial paper, and the associated swap transaction expired.

(v) The company is authorized to issue commercial paper to a maximum of $1,500 million having a term not to exceed 365 days. Commercial paper is supported by unutilized credit facilities (see B. Credit Facilities).

(vi) Equipment leases with interest rates between 6.5% and 15.7% and maturity dates ranging from 2008 to 2037.

(vii) Future minimum amounts payable under capital leases and other long-term debt are as follows:

($ millions)	Capital Leases	Other Long-term Debt
2008	9	529 [a]
2009	9	—
2010	9	—
2011	10	500
2012	10	—
Later years	277	2 680
Total minimum payments	324	3 709
Less amount representing imputed interest	222	
Present value of obligation under capital leases	102	

(a) Long-term debt due in the next year will be refinanced with available credit facilities

Long-term Debt (per cent)

	2007	2006
Variable rate	**19**	37
Fixed rate	**81**	63

B. Credit facilities

During 2007, our $300 million bilateral credit facility was amended and extended by one year to 2008 and the credit limit was increased by $30 million to $330 million total funds available. Our $2 billion syndicated credit facility was renegotiated and extended by one year to have a five year term expiring in June 2012 and the company's commercial paper program limit was increased by $300 million from $1.2 billion to $1.5 billion. Additionally, a $15 million revolving demand credit facility was renegotiated and increased by $15 million to $30 million. At December 31, 2007, the company had available credit facilities of $2,375 million, of which $1,579 was undrawn as follows:

($ millions)	**2007**
Facility that is fully revolving for 364 days, has a term period of one year and expires in 2008	330
Facility that is fully revolving for a period of five years and expires in 2012	2 000
Facilities that can be terminated at any time at the option of the lenders	45
Total available credit facilities	2 375
Credit facilities supporting outstanding commercial paper	522
Credit facilities supporting standby letters of credit	274
Total undrawn credit facilities	1 579

7. FINANCIAL INSTRUMENTS

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 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.

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 manage the exposure to losses that could result if commodity prices or foreign currency exchange 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 can 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, or vice versa; a domestic currency debt may be converted to a foreign currency debt.

See below for more technical details and amounts.

(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 asset retirement and pension obligations), and long-term debt. Unless otherwise noted, carrying values reflect the current fair value of the company's financial instruments.

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 hedge methodology outlined 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, other than the foreign exchange effect, of this debt until the gains or losses are realized.

The following table summarizes estimated fair value information about the company's financial instruments recognized in the Consolidated Balance Sheets at December 31:

	2007		2006	
($ millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	**569**	**569**	521	521
Accounts receivable	**1 416**	**1 416**	1 050	1 050
Current liabilities	**2 507**	**2 507**	1 947	1 947
Long-term debt	**3 811**	**3 926**	2 363	2 505

(b) Hedges

Fair Value Hedges

Suncor 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 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, 2007, the company had interest rate derivatives classified as fair value hedges outstanding for up to four years relating to fixed-rate debt. There was no ineffectiveness recognized on interest rate swaps designated as fair value hedges during the twelve-month period ended December 31, 2007. The notional amounts of interest rate swap contracts outstanding at December 31, 2007 are detailed in note 6, Long-Term Debt.

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 the accounts as an adjustment to operating revenues. The earnings impact associated with hedge ineffectiveness on derivative contracts to hedge risks specific to individual transactions during the twelve-month period ended December 31, 2007, was a gain of $4 million, net of income taxes of $2 million.

Cash Flow Hedges

Suncor 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 oil 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 swap transactions and foreign exchange forward contracts.

At December 31, 2007, the company had hedged a portion of its forecasted Canadian and U.S. dollar denominated cash flows subject to U.S. dollar WTI commodity risk for 2008.

The earnings impact associated with realized and unrealized hedge ineffectiveness on derivative contracts designated as cash flow hedges during the twelve-month period ended December 31, 2007 was a loss of $5 million, net of income taxes of $2 million.

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. For accounting purposes, amounts received or paid on settlement are recorded as part of the related hedged sales or purchase transactions.

As at December 31, 2007, assets increased by $27 million and liabilities increased by $31 million as a result of recording derivative instruments at fair value in accordance with the new standards.

Contracts outstanding at December 31 were as follows:

Revenue Hedges

Strategic Crude Oil	Quantity (bpd)	Average Price (US$/bbl) [a]	Revenue Hedged (Cdn$ millions) [b]	Hedge Period [c]
As at December 31, 2007				
Costless collars	**10 000**	**59.85 – 101.06**	**216 – 365**	**2008**
As at December 31, 2006				
Costless collars	60 000	51.64 – 93.26	1 318 – 2 380	2007
Costless collars	10 000	59.85 – 101.06	255 – 431	2008
As at December 31, 2005				
Costless collars	7 000	50.00 – 92.57	149 – 276	2006
Costless collars	7 000	50.00 – 92.57	149 – 276	2007

Natural Gas	Quantity (GJ/day)	Average Price (Cdn$/GJ)	Revenue Hedged (Cdn$ millions)	Hedge Period [c]
As at December 31, 2007				
Swaps	**–**	**–**	**–**	**–**
As at December 31, 2006				
Swaps	4 000	6.11	9	2007
As at December 31, 2005				
Swaps	4 000	6.58	10	2006
Costless collars	25 000	10.76 – 16.13	24 – 36	2006 [d]
Costless collars	10 000	8.75 – 13.38	19 – 29	2006 [e]
Swaps	4 000	6.11	9	2007

Margin Hedges	Quantity (bpd)	Average Margin (US$/bbl)	Margin Hedged (Cdn$ millions) [b]	Hedge Period [c]
Refined product sale and crude purchase swaps				
As at December 31, 2007	**–**	**–**	**–**	**–**
As at December 31, 2006	–	–	–	–
As at December 31, 2005	5 100	11.69	10	2006 [f]

Foreign Currency Hedges	Notional (Euro Millions)	Average Forward Rate	Dollars Hedged (Cdn$ millions)	Hedge Period [c]
As at December 31, 2007				
Euro/Cdn forward	**–**	**–**	**–**	**–**
As at December 31, 2006				
Euro/Cdn forward	20.6	1.41	29.0	2007 [g]
As at December 31, 2005				
Euro/Cdn forward	9.9	1.39	13.8	2006 [h]
Euro/Cdn forward	20.6	1.41	29.0	2007 [g]

(a) Average price for crude costless collars is US$ WTI per barrel at Cushing, Oklahoma.

(b) The revenue and margin hedged is translated to Cdn$ at the respective year-end exchange rate and is subject to change as the US$/Cdn$ exchange rate fluctuates during the hedge period.

(c) Original hedge term is for the full year unless otherwise noted.

(d) For the period January to March 2006, inclusive.

(e) For the period April to October 2006, inclusive.

(f) For the period January to May 2006, inclusive.

(g) Settlement for applicable forwards occurring within the period April to September 2007.

(h) Settlement for applicable forward was March 2006.

Fair Value of Hedging Derivative Financial Instruments

The fair value of hedging derivative financial instruments as recorded, is the estimated amount, based on broker quotes and/or internal valuation models 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 at December 31:

($ millions)	**2007**	2006
Revenue hedge swaps and collars	**(11)**	22
Fixed to floating interest rate swaps	**8**	16
Specific hedges of individual transactions	**12**	(4)
Fair value of outstanding hedging derivative financial instruments	**9**	34

Accumulated Other Comprehensive Income (AOCI)

A reconciliation of changes in AOCI attributable to derivative hedging activities for the twelve-month period ending December 31, 2007, is as follows:

($ millions)	**2007**
AOCI attributable to derivatives and hedging activities, recorded upon initial adoption on January 1, 2007, net of income taxes of $5	8
Current year net changes arising from cash flow hedges, net of income taxes of $1	**8**
Net unrealized hedging gains at the beginning of the year reclassified to earnings during the period, net of income taxes of $2	**(3)**
AOCI attributable to derivatives and hedging activities, at December 31, 2007, net of income taxes of $4	**13**

(c) Energy Marketing and Trading Activities

In addition to the financial derivatives used for hedging activities, the company uses physical and financial energy contracts, including swaps, forwards and options to earn trading and marketing revenues. The financial energy trading activities are accounted for using the mark-to-market method and, as such, these derivative instruments are recorded at fair value at each balance sheet date. Physical energy marketing contracts involve activities intended to enhance prices and satisfy physical deliveries to customers. The results of these activities are reported as revenue and as energy trading and marketing expenses in the Consolidated Statements of Earnings and Comprehensive Income. The net pretax earnings (loss) for the years ended December 31 were as follows:

Net Pretax Earnings (Loss)

($ millions)	**2007**	2006	2005
Physical energy contracts trading activity	**21**	41	15
Financial energy contracts trading activity	**(3)**	(3)	5
General and administrative costs	**(4)**	(3)	(3)
Total	**14**	35	17

The fair value of unsettled (unrealized) energy trading assets and liabilities at December 31 were as follows:

($ millions)	**2007**	2006
Energy trading assets	**18**	16
Energy trading liabilities	**21**	13
Net energy trading assets (liabilities)	**(3)**	3

Change in fair value of net assets

($ millions)	2007
Fair value of contracts at December 31, 2006	3
Fair value of contracts realized during the period	**29**
Fair value of contracts entered into during the period	**(56)**
Changes in values attributable to market price and other market changes during the period	**21**
Fair Value of Contracts outstanding at December 31, 2007	**(3)**

The source of the valuations of the above contracts was based on actively quoted prices and/or internal valuation models.

(d) Counterparty Credit Risk

The company may be exposed to certain losses in the event that counterparties to the 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. The company minimizes this risk by ensuring that substantially all agreements are with counterparties of investment grade. Risk is also minimized through regular management review of credit ratings and potential exposure to such counterparties. At December 31, the company had exposure to credit risk with counterparties as follows:

($ millions)	2007	2006
Derivative contracts not accounted for as hedges	**18**	16
Derivative contracts accounted for as hedges	**20**	35
Total	**38**	51

8. ACCRUED LIABILITIES AND OTHER

($ millions)	2007	2006
Asset retirement obligations [(a)]	**882**	704
Employee future benefits liability (see note 9)	**175**	170
Employee and director incentive plans [(b)]	**173**	143
Deferred revenue	**164**	143
Environmental remediation costs [(c)]	**11**	26
Other	**29**	28
Total	**1 434**	1 214

(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)	2007	2006
Asset retirement obligations, beginning of year	**808**	543
Liabilities incurred	**275**	286
Liabilities settled	**(59)**	(54)
Accretion of asset retirement obligations	**48**	33
Asset retirement obligations, end of year	**1 072**	808

The portion of the ARO expected to be paid within one year is shown within current liabilities and amounts to an additional $190 million (2006 – $104 million).

The total undiscounted amount of estimated future cash flows required to settle the obligations at December 31, 2007, was approximately $2.2 billion (2006 – $1.7 billion). The liability recognized in 2007 was discounted using the company's credit-adjusted risk-free rate of 6.0% (2006 – 5.5%). Payments to settle the ARO occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 30 years.

A significant portion of the company's assets, including the upgrading facilities at the oil sands operation and the two downstream refineries located in Sarnia and Commerce City, 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) Employee and Director Incentive Plans

The portion of the employee and director incentive plans expected to be paid within one year is shown within current liabilities and amounts to an additional $50 million (2006 – $32 million).

(c) Environmental Remediation Costs

The portion of the environmental remediation costs expected to be paid within one year is shown within current liabilities and amounts to an additional $19 million (2006 – $17 million). Environmental remediation costs are obligations assumed through the purchase of the Commerce City refineries.

9. EMPLOYEE FUTURE BENEFITS LIABILITY

Suncor employees are eligible to receive certain pension, health care and insurance benefits when they retire. The related ***Benefit Obligation*** *or commitment that Suncor has to employees and retirees at December 31, 2007, was $1,063 million (2006 – $1,024 million).*

As required by government regulations, Suncor sets aside funds with an independent trustee to meet certain of the 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 2007, ***Plan Assets*** *to meet the* ***Benefit Obligation*** *were $684 million (2006 – $616 million).*

The excess of the ***Benefit Obligation*** *over* ***Plan Assets*** *of $379 million (2006 – $408 million) represents the* ***Net Unfunded Obligation****.*

See below for more technical details and amounts.

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 plan was performed as at December 31, 2006.

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.

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:

($ millions)	Pension Benefits 2007	Pension Benefits 2006	Other Post-Retirement Benefits 2007	Other Post-Retirement Benefits 2006
Change in benefit obligation				
Benefit obligation at beginning of year	**866**	745	**158**	144
Service costs	**51**	44	**4**	5
Interest costs	**45**	40	**8**	8
Plan participants' contributions	**5**	4	**—**	—
Foreign exchange	**(5)**	(2)	**(2)**	—
Actuarial (gain) loss	**(28)**	67	**(3)**	5
Benefits paid	**(33)**	(32)	**(3)**	(4)
Benefit obligation at end of year [(a)(d)]	**901**	866	**162**	158
Change in plan assets [(b)]				
Fair value of plan assets at beginning of year	**616**	479	**—**	—
Actual return on plan assets	**7**	60	**—**	—
Employer contributions	**88**	103	**—**	—
Foreign exchange	**(2)**	—	**—**	—
Plan participants' contributions	**5**	4	**—**	—
Benefits paid	**(30)**	(30)	**—**	—
Fair value of plan assets at end of year [(d)]	**684**	616	**—**	—
Net unfunded obligation	**(217)**	(250)	**(162)**	(158)
Items not yet recognized in earnings:				
Unamortized net actuarial loss [(c)]	**158**	177	**43**	52
Unamortized past service costs	**—**	—	**(20)**	(23)
Accrued benefit liability	**(59)**	(73)	**(139)**	(129)
Current liability	**(41)**	(46)	**(3)**	(3)
Long-term liability	**(40)**	(44)	**(136)**	(126)
Long-term asset	**22**	17	**—**	—
Total accrued benefit liability	**(59)**	(73)	**(139)**	(129)

(a) Obligations are based on the following assumptions:

(percent)	Pension Benefit Obligations 2007	Pension Benefit Obligations 2006	Other Post-Retirement Benefits Obligations 2007	Other Post-Retirement Benefits Obligations 2006
Discount rate	**5.25**	5.00	**5.25**	5.00
Rate of compensation increase	**5.00**	5.00	**4.75**	4.75

A one percent change in the assumptions at which pension benefits and other post-retirement benefits liabilities could be effectively settled is as follows:

($ millions)	Rate of Return on Plan Assets 1% increase	Rate of Return on Plan Assets 1% decrease	Discount Rate 1% increase	Discount Rate 1% decrease	Rate of Compensation Increase 1% increase	Rate of Compensation Increase 1% decrease
Increase (decrease) to net periodic benefit cost	(6)	6	(21)	25	10	(9)
Increase (decrease) to benefit obligation	—	—	(140)	165	35	(32)

In order to measure the expected cost of other post-retirement benefits, a 9% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2007 (2006 – 9.5%; 2005 – 10%). It is assumed that this rate will remain constant in 2008 and 2009 and will decrease by 0.5% annually, to 5% by 2017, and remain at that level thereafter.

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	1	(1)
Increase (decrease) to the health care component of the accumulated post-retirement benefit obligation	15	(12)

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

(c) 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 11 years for pension benefits (2006 – 11 years; 2005 – 11 years), and over the expected average future service life to full eligibility age of 12 years for other post-retirement benefits (2006 – 10 years; 2005 – 9 years).

(d) 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 2007	2006	Other Post-Retirement Benefits 2007	2006
Partially funded plans	**901**	866	**—**	—
Unfunded plans	**—**	—	**162**	158
Benefit obligation at end of year	**901**	866	**162**	158

Components of Net Periodic Benefit Cost [(i)]

($ millions)	Pension Benefits 2007	2006	2005	Other Post-Retirement Benefits 2007	2006	2005
Current service costs	**51**	44	32	**4**	5	5
Interest costs	**45**	40	38	**8**	8	6
Expected return on plan assets [(ii)]	**(42)**	(32)	(28)	**—**	—	—
Amortization of net actuarial loss	**25**	28	21	**3**	1	1
Net periodic benefit cost recognized [(iii)]	**79**	80	63	**15**	14	12

Components of Net Incurred Benefit Cost [(i)]

($ millions)	Pension Benefits 2007	2006	2005	Other Post-Retirement Benefits 2007	2006	2005
Current service costs	**51**	44	32	**4**	5	5
Interest costs	**45**	40	38	**8**	8	6
Actual return on plan assets [(ii)]	**(7)**	(60)	(41)	**—**	—	—
Actuarial (gain) loss	**(28)**	67	75	**(4)**	5	8
Net incurred benefit cost	**61**	91	104	**8**	18	19

(i) The net periodic benefit cost includes certain accounting adjustments made to allocate costs to the periods in which employee services are rendered, consistent with the long-term nature of the benefits. Costs actually incurred in the period (arising from actual returns on plan assets and actuarial gains and losses in the period) differ from allocated costs recognized.

(ii) 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 11 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.

(iii) Pension expense is based on the following assumptions:

(percent)	Pension Benefit Expense 2007	2006	2005	Other Post-Retirement Benefits Expense 2007	2006	2005
Discount rate	**5.00**	5.00	5.75	**5.00**	5.00	5.75
Expected return on plan assets	**6.50**	6.50	6.75	**N/A**	N/A	N/A
Rate of compensation increase	**5.00**	4.50	4.50	**4.75**	4.25	4.25

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, 2007 and 2006, and the target allocation for 2008, are as follows:

	Target Allocation %	Plan Assets %	
Asset Category	2008	**2007**	2006
Equities	60	**58**	61
Fixed income	40	**42**	39
Total	100	**100**	100

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

Cash Flows

The company expects that contributions to its pension plans in 2008 will be $72 million, including approximately $10 million for the company's supplemental executive and supplemental retirement plans. Expected benefit payments from all of the plans are as follows:

	Pension Benefits	Other Post-Retirement Benefits
2008	38	5
2009	42	6
2010	45	6
2011	47	7
2012	51	8
2013 - 2017	310	47
Total	533	79

Defined Contribution Pension Plan

The company has a Canadian defined contribution plan and a U.S. 401(k) savings plan, under which both the company and employees make contributions. Company contributions and corresponding expense totalled $13 million in 2007 (2006 – $11 million; 2005 – $10 million).

10. 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 two rates and the dollar effect is as follows:

	2007		2006		2005	
($ millions)	Amount	%	Amount	%	Amount	%
Federal tax rate	**1 053**	**32**	1 256	33	648	35
Provincial abatement	**(294)**	**(9)**	(381)	(10)	(186)	(10)
Federal surtax	**33**	**1**	43	1	21	1
Provincial tax rates	**307**	**9**	395	10	213	12
Statutory tax and rate	**1 099**	**33**	1 313	34	696	38
Adjustment of statutory rate for future rate reductions	**(133)**	**(4)**	(146)	(4)	(84)	(5)
	966	**29**	1 167	30	612	33
Add (deduct) the tax effect of:						
Crown royalties	**—**	**—**	125	3	119	6
Resource allowance [(a)]	**—**	**—**	(42)	(1)	(48)	(2)
Large corporations tax	**—**	**—**	2	—	23	1
Tax rate changes on opening future income taxes [(b)]	**(427)**	**(13)**	(419)	(11)	—	—
Attributed Canadian royalty income	**—**	**—**	(23)	(1)	(24)	(1)
Stock-based compensation	**33**	**1**	18	1	8	—
Assessments and adjustments	**(1)**	**—**	(9)	—	7	—
Capital gains	**(40)**	**(1)**	—	—	(6)	—
Other	**(18)**	**(1)**	16	—	3	—
Income taxes and effective rate	**513**	**15**	835	21	694	37

(a) The resource allowance was a federal tax deduction allowed as a proxy for non-deductible provincial Crown royalties. As required by GAAP in Canada, resource allowance is accounted for by adjusting the statutory tax rate by the resource allowance rate. Resource allowance has been phased out effective January 1, 2007.

(b) During 2007, the federal government enacted tax rate reductions totalling $427 million. During the fourth quarter of 2007 the federal government substantively enacted a 3.5% reduction to its federal corporate tax rates. Accordingly, the company recognized a reduction in future income tax expense of $360 million related to the revaluation of its opening future income tax balances. During the second quarter of 2007 the federal government substantively enacted a 0.5% reduction to its federal corporate tax rates. Accordingly, the company recognized a reduction in future income tax expense of $67 million related to the revaluation of its opening future income tax balances.

During 2006, there were both federal and provincial government rate reductions totalling $419 million. During the second quarter of 2006 the federal government substantively enacted a 3.1% reduction to its federal corporate tax rates. Accordingly, the company recognized a reduction in future income tax expense of $292 million related to the revaluation of its opening future income tax balances. As well, the provincial government of Alberta substantively enacted a 1.5% reduction to its provincial corporate tax rates during the second quarter of 2006. Accordingly, the company recognized a reduction in future income tax expense of $127 million related to the revaluation of its opening future income tax balances.

In 2007 net income tax payments totalled $152 million (2006 – $36 million; 2005 – $77 million).

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

	2007		2006	
($ millions)	Current	Non-Current	Current	Non-Current
Future income tax assets:				
Employee future benefits	**16**	**—**	12	—
Asset retirement obligations	**49**	**—**	32	—
Inventories	**84**	**—**	59	—
Other	**(19)**	**—**	6	—
	130	**—**	109	—
Future income tax liabilities:				
Excess of book values of assets over tax values	**—**	**4 378**	—	4 413
Deferred maintenance shutdown costs	**—**	**89**	—	43
Employee future benefits	**—**	**(102)**	—	(88)
Asset retirement obligations	**—**	**(220)**	—	(203)
Attributed Canadian royalty income	**—**	**—**	—	(93)
Other	**—**	**67**	—	—
	—	**4 212**	—	4 072

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

(a) Operating Commitments

In order to ensure continued availability of, and access to, facilities and services to meet its operational requirements, the company periodically enters into transportation service agreements for pipeline capacity and energy services agreements as well as non-cancellable operating leases for service stations, office space and other property and equipment. Under contracts existing at December 31, 2007, future minimum amounts payable under these leases and agreements are as follows:

($ millions)	Pipeline Capacity and Energy Services (1)	Operating Leases
2008	284	46
2009	313	38
2010	388	31
2011	379	26
2012	364	23
Later years	5 284	134
	7 012	298

(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, including the shipment of crude oil from Fort McMurray to Hardisty, Alberta. The agreements commenced in 1999 and extend up to 2033. As the initial shipper on one of the pipelines, Suncor's tolls payable are subject to annual adjustments.

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. Since October 1999, this third-party has also managed the operations of Suncor's existing energy services facility at its oil sands operations.

(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 carries both property damage and business interruption insurance policies with a combined coverage limit of up to US$1.7 billion, net of deductible amounts or waiting periods. The primary property loss policy of US$250 million has a deductible of US$10 million per incident. Suncor has 100% ownership interest in Fort Insurance Limited, an insurance company which provides coverage to Suncor including business interruption coverage for oil sands with a limit of US$150 million and a deductible of the greater of 30 days or US$50 million. The excess coverage of US$1.3 billion can be used for either property damage or business interruption coverage for oil sands operations. Excess business interruption coverage begins the greater of 90 days from the date of the incident or US$250 million in gross earnings lost. For the purposes of determining loss for business interruption claims, the excess coverage has a ceiling of US$50 WTI and a lost production maximum of 150,000 barrels per day.

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) Guarantees, Variable Interest Entities (VIE), and Off-Balance Sheet Arrangements

At December 31, 2007, the company had various indemnification agreements with third parties as described below.

The company has a securitization program in place to sell, on a revolving, fully serviced and limited recourse basis, up to $170 million of accounts receivable (2006 – $170 million) having a maturity of 45 days or less, to a third party. The third party is a multiple party securitization vehicle that provides funding for numerous asset pools. As at December 31, 2007, no outstanding accounts receivable had been sold under the program (2006 – $170 million). Although the company does not believe it has any significant exposure to credit losses, under the recourse provisions, the company provided indemnification against potential credit losses for certain counterparties. This indemnification did not exceed $42 million in 2007 and no contingent liability or earnings impact have been recorded for this indemnification as the company believes it has no significant exposure to credit losses. Proceeds received from new securitizations and proceeds from collections reinvested in securitizations on a revolving basis for the year ended December 31, 2007, were $170 million and approximately $1,530 million, respectively. The company recorded an after-tax loss of approximately $4 million on the securitization program in 2007 (2006 – $2 million; 2005 – $4 million).

In 1999, the company entered into an equipment sale and leaseback arrangement with a VIE for proceeds of $30 million. The VIE's sole asset is the equipment sold to it and leased back by the company. The VIE was consolidated effective January 1, 2005. The initial lease term covers a period of seven years and is accounted for as an operating lease. The company repurchased the equipment in 2006 for $21 million. As at December 31, 2007, the VIE did not have any assets or liabilities.

The company has agreed to indemnify holders of the 6.50% notes, the 7.15% notes, the 5.95% notes and the company's credit facility lenders (see note 6) for added costs relating to taxes, assessments or other government charges or conditions, including any required withholding amounts. Similar indemnity terms apply to the receivables securitization program, and 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.

12. SHARE CAPITAL

(a) 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.

(b) Issued

	Common Shares Number (thousands)	Amount ($ millions)
Balance as at December 31, 2004	454 241	651
Issued for cash under stock option plans	3 302	74
Issued under dividend reinvestment plan	122	7
Balance as at December 31, 2005	457 665	732
Issued for cash under stock option plans	2 147	52
Issued under dividend reinvestment plan	132	10
Balance as at December 31, 2006	459 944	794
Issued for cash under stock options plan	**2 694**	**74**
Issued under dividend reinvestment plan	**145**	**13**
Balance as at December 31, 2007	**462 783**	**881**

Common Share Options

A common share 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 directors that hold options must earn the right to exercise them. This is done by the employee or director fulfilling a time requirement for service to the company, and with respect to certain options, subject to accelerated vesting should the company meet predetermined performance criterion. Once this right has been earned, these options are considered vested.

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 options are granted.

See below for more technical details and amounts on the company's stock option plans:

(a) Stock Option Plans

(i) Executive Stock Plan

Under this plan, the company granted 479,000 common share options in 2007 (2006 – 538,000; 2005 – 518,000) 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.

(ii) SunShare 2012 Performance Stock Option Plan

During 2007, the company granted 7,843,000 options to all eligible permanent full-time and part-time employees, both executive and non-executive, under its new employee stock option incentive plan ("SunShare 2012") which was approved at the Annual and Special Meeting of shareholders on April 26, 2007. Under this plan, meeting specified performance targets may accelerate the vesting of some options, such that 25% of outstanding options may vest on January 1, 2010, and the remaining 75% of outstanding options may vest on January 1, 2013. All unvested options at January 1, 2013, which have not previously been cancelled, will automatically expire.

(iii) SunShare Performance Stock Option Plan

During 2007, the company granted 1,045,000 options (2006 – 1,637,000; 2005 – 1,253,000) to eligible permanent full-time and part-time employees, both executive and non-executive, under its employee stock option incentive plan ("SunShare"). Under SunShare, meeting specified performance targets accelerates the vesting of some or all options.

On January 31, 2005, in connection with the achievement of a predetermined performance criterion, approximately 25% of the then outstanding options vested under the SunShare plan. On June 30, 2005, an additional predetermined performance criterion under the SunShare plan was met, resulting in the vesting of 50% of the outstanding, unvested SunShare options on April 30, 2008. During 2007, the final predetermined performance criterion was met, and as a result, the remaining 50% of the outstanding, unvested SunShare options will vest on April 30, 2008.

(iv) Key Contributor Stock Option Plan

Under this plan, the company granted 1,185,000 common share options in 2007 (2006 – 1,050,000; 2005 – 901,000) to non-insider senior managers and key employees. Options granted have a 10-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, 2004	20 687	5.22 – 42.02	24.49
Granted	2 672	36.93 – 71.13	48.27
Exercised	(3 302)	5.22 – 41.38	20.71
Cancelled	(854)	26.14 – 70.53	30.82
Outstanding, December 31, 2005	19 203	5.22 – 71.13	28.12
Granted	3 224	73.36 – 101.79	89.95
Exercised	(2 147)	5.22 – 61.92	20.99
Cancelled	(471)	25.00 – 96.10	46.66
Outstanding, December 31, 2006	19 809	7.77 – 101.79	38.48
Granted	**10 552**	**70.56 – 107.02**	**93.36**
Exercised	**(2 694)**	**7.77 – 92.11**	**22.75**
Cancelled	**(667)**	**25.31 – 101.73**	**65.68**
Outstanding, December 31, 2007	**27 000**	**10.13 – 107.02**	**60.61**
Exercisable, December 31, 2007	**7 276**	**10.13 – 100.04**	**30.87**

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)	**2007**	2006	2005
	7 285	7 970	10 724

The following table is an analysis of outstanding and exercisable common share options as at December 31, 2007:

	Outstanding			Exercisable	
Exercise Prices ($)	Number (thousands)	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price Per Share ($)	Number (thousands)	Weighted-Average Exercise Price Per Share ($)
10.13 – 17.45	1 598	2	15.40	1 598	15.40
21.35 – 28.93	8 538	4	27.00	3 588	26.26
31.59 – 42.65	2 656	6	37.83	1 527	37.32
45.51 – 72.42	965	5	56.81	71	52.83
73.36 – 92.68	4 993	7	88.29	475	91.32
93.36 – 107.02	8 250	7	95.16	17	98.07
Total	27 000	6	60.61	7 276	30.87

Fair Value of Options Granted

The fair values of all common share options granted during the period are estimated as at the grant date using a Monte Carlo simulation approach for the SunShare 2012 option plan and the Black-Scholes option-pricing model for all other option plans.

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:

	2007	2006	2005
Annual dividend per share	**$0.38**	$0.30	$0.24
Risk-free interest rate	**4.22%**	4.08%	3.69%
Expected life	**6 years**	5 years	6 years
Expected volatility	**30%**	29%	28%
Weighted-average fair value per option	**$29.77**	$29.17	$15.42

Stock-based compensation expense recognized for the year ended December 31, 2007 related to stock option plans was $103 million (2006 – $53 million; 2005 – $23 million).

Common share options granted prior to January 1, 2003 are not recognized as compensation expense in the Consolidated Statement of Earnings and Comprehensive Income. The company's reported net earnings attributable to common shareholders and earnings per share prepared in accordance with the fair value method of accounting for stock-based compensation would have been reduced for all common share options granted prior to 2003 to the pro forma amounts stated below:

($ millions, except per share amounts)	**2007**	2006	2005
Net earnings attributable to common shareholders – as reported	**2 832**	2 971	1 158
Less: compensation cost under the fair value method for pre-2003 options	**8**	15	13
Pro forma net earnings attributable to common shareholders for pre-2003 options	**2 824**	2 956	1 145
Basic earnings per share			
As reported	**6.14**	6.47	2.54
Pro forma	**6.12**	6.44	2.51
Diluted earnings per share			
As reported	**6.02**	6.32	2.48
Pro forma	**6.00**	6.29	2.46

(b) Deferred Share Units (DSUs)

The company had 1,168,000 DSUs outstanding at December 31, 2007 (1,170,000 at December 31, 2006). 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 2007, 20,000 DSUs were redeemed for cash consideration of $2 million (2006 – 59,000 redeemed for cash consideration of $5 million; 2005 – 81,000 redeemed for cash consideration of $5 million). Over time, DSU unitholders are entitled to receive additional DSUs equivalent in value to future notional dividend reinvestments. Final DSU redemption amounts are subject to change depending on the company's share price at the time of exercise. Accordingly, the company revalues the DSUs on each reporting date, with any changes in value recorded as an adjustment to compensation expense in the period. As at December 31, 2007, the total liability related to the DSUs was $126 million (2006 – $107 million), of which $5 million (2006 – $2 million) was classified as current.

During 2007, total pretax compensation expense related to DSUs was $21 million (2006 – $25 million; 2005 – $39 million).

(c) Performance Share Units (PSUs)

During 2007, the company issued 415,000 PSUs (2006 – 397,000; 2005 – 453,000) under its Performance Share Unit Compensation Plan. PSUs granted replace the remuneration value of reduced grants under the company's stock option plans. 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. Pretax expense recognized for PSUs during 2007 was $60 million (2006 – $42 million; 2005 – $21 million).

13. EARNINGS PER COMMON SHARE

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

($ millions)	**2007**	2006	2005
Net earnings attributable to common shareholders	**2 832**	2 971	1 158
(millions of common shares)			
Weighted-average number of common shares	**461**	459	456
Dilutive securities:			
Shares issued under stock-based compensation plans	**10**	11	10
Weighted-average number of diluted common shares	**471**	470	466
(dollars per common share)			
Basic earnings per share [a]	**6.14**	6.47	2.54
Diluted earnings per share [b]	**6.02**	6.32	2.48

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

(a) Basic earnings per share is 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.

14. ACQUISITION OF REFINERY AND RELATED ASSETS

On May 31, 2005, the company acquired all of the issued shares of the Colorado Refining Company, an indirect wholly-owned subsidiary of Valero Energy Corp. for cash consideration of $37 million. Additional payments for working capital and associated inventory brought the total purchase price to $62 million. The acquired company's principal assets are a Commerce City refinery and a products terminal located in Grand Junction, Colorado. The allocation of fair value to the assets acquired and liabilities assumed was $79 million for property, plant and equipment, $30 million for inventory and $41 million for environmental liabilities assumed. The fair value assigned to other liabilities was $6 million. The acquisition was accounted for by the purchase method of accounting.

The results of operations for these assets have been included in the consolidated financial statements from the date of acquisition. The new operations have been reported as part of the refining and marketing segment in the Schedules of Segmented Data.

15. FINANCING EXPENSES (INCOME)

($ millions)	**2007**	2006	2005
Interest on debt	**189**	150	151
Capitalized interest	**(189)**	(129)	(119)
Net interest expense	**—**	21	32
Foreign exchange gain on long-term debt	**(252)**	—	(37)
Other foreign exchange loss (gain)	**41**	18	(10)
Total financing (income) expenses	**(211)**	39	(15)

Cash interest payments in 2007 totaled $183 million (2006 – $146 million; 2005 – $149 million).

16. INVENTORIES

($ millions)	**2007**	2006
Crude oil	**332**	249
Refined products	**126**	200
Materials, supplies and merchandise	**150**	140
Total	**608**	589

The replacement cost of crude oil and refined product inventories exceeded their LIFO carrying value by $415 million (2006 – $243 million) as at December 31, 2007.

During 2007, the company recorded a pretax gain of $57 million related to a permanent reduction in LIFO inventory layers, as the LIFO layers were lower than current cost (2006 – $6 million pretax gain).

17. RELATED PARTY TRANSACTIONS

The following table summarizes the company's related party transactions after eliminations for the year. These transactions are in the normal course of operations and have been carried out on the same terms as would apply with unrelated parties.

($ millions)	**2007**	2006	2005
Operating revenues			
Sales to refining and marketing segment joint ventures:			
Refined products	**329**	294	327
Petrochemicals	**163**	136	279

The company has supply agreements with two refining and marketing segment joint ventures for the sale of refined products. The company also has a supply agreement with a refining and marketing segment joint venture for the sale of petrochemicals.

At December 31, 2007, amounts due from refining and marketing segment joint ventures were $17 million (2006 – $20 million).

Sales to and balances with refining and marketing segment joint ventures are established and agreed to by the various parties and approximate fair value.

18. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

As at December 31 ($ millions)	**2007**	2006
Unrealized foreign currency translation adjustment	**(266)**	(71)
Unrealized gains and losses on derivative hedging activities	**13**	—
Total	**(253)**	(71)

19. SUPPLEMENTAL INFORMATION

($ millions)	2007	2006	2005
Geographic areas			
Revenues			
Canada	**13 733**	12 213	8 037
U.S.	**4 091**	3 532	3 090
Other	**109**	84	2
	17 933	15 829	11 129
Total assets			
Canada	**21 389**	16 087	12 945
U.S.	**2 440**	2 379	2 003
Other	**338**	293	178
	24 167	18 759	15 126
Export sales [(a)]	**876**	810	648
Exploration expenses			
Geological and geophysical	**26**	51	22
Other	**—**	1	1
Cash costs	**26**	52	23
Dry hole costs	**69**	52	33
Cash and dry hole costs [(b)]	**95**	104	56
Leasehold impairment [(c)]	**—**	2	13
	95	106	69
Taxes other than income taxes			
Excise taxes [(d)]	**568**	538	482
Production, property and other taxes	**80**	57	47
	648	595	529
Allowance for doubtful accounts	**3**	4	4

(a) Sales of crude oil, natural gas and refined products from Canada to customers in the United States and sales of petrochemicals to customers in the United States and Europe.

(b) Included in the Consolidated Statements of Earnings and Comprehensive Income as exploration expenses.

(c) Included in depreciation, depletion and amortization in the Consolidated Statements of Earnings and Comprehensive Income.

(d) Included in operating revenues in the Consolidated Statements of Earnings and Comprehensive Income.

20. 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 earnings and comprehensive income as reported:

($ millions)	Notes	2007	2006	2005
Net earnings as reported, Canadian GAAP		**2 832**	2 971	1 158
Adjustments				
Derivatives and hedging activities	(a)	**—**	11	83
Stock-based compensation expense	(b)	**15**	(19)	(26)
Research and development costs	(g)	**(34)**	—	—
Income tax expense		**4**	(3)	(28)
Net earnings from continuing operations, U.S. GAAP		**2 817**	2 960	1 187
Cumulative effect of change in accounting principles, net of income taxes of $nil (2006 – $2; 2005 – $nil)	(b)	**—**	(4)	—
Net earnings, U.S. GAAP		**2 817**	2 956	1 187
Derivatives and hedging activities, net of income taxes of $nil (2006 – $3; 2005 – $70)	(a)	**5**	6	140
Minimum pension liability, net of income taxes of $nil (2006 – $20; 2005 – $8)	(c)	**—**	39	(15)
Pension and Post-retirement obligation, net of income taxes of $8	(c)	**17**	—	—
Foreign currency translation adjustment	(d)	**(195)**	10	(26)
Comprehensive income, U.S. GAAP		**2 644**	3 011	1 286

Per common share (dollars)	**2007**	2006	2005
Net earnings per share from continuing operations, U.S. GAAP			
Basic	**6.11**	6.45	2.60
Diluted	**5.98**	6.29	2.55
Net earnings per share, U.S. GAAP			
Basic	**6.11**	6.44	2.60
Diluted	**5.98**	6.29	2.55

The application of U.S. GAAP would have the following effects on the consolidated balance sheets as reported:

		December 31, 2007		December 31, 2006	
	Notes	As Reported	U.S. GAAP	As Reported	U.S. GAAP
Current assets		**2 818**	**2 818**	2 302	2 302
Property, plant and equipment, net	(g)	**20 945**	**20 911**	16 160	16 160
Deferred charges and other	(a,c)	**404**	**404**	297	323
Total assets		**24 167**	**24 133**	18 759	18 785
Current liabilities		**3 097**	**3 097**	2 158	2 158
Long-term borrowings	(a)	**3 811**	**3 811**	2 363	2 376
Accrued liabilities and other	(b,c)	**1 434**	**1 602**	1 214	1 430
Future income taxes	(a,c,g)	**4 212**	**4 147**	4 072	4 002
Share capital	(b)	**881**	**944**	794	842
Contributed surplus	(b)	**194**	**240**	100	153
Retained earnings	(a,b,g)	**10 791**	**10 667**	8 129	8 026
Accumulated other comprehensive income	(a,c,d)	**(253)**	**(375)**	(71)	(202)
Total liabilities and shareholders' equity		**24 167**	**24 133**	18 759	18 785

(a) Derivative Financial Instruments

The adoption of CICA Handbook section 1530 "Comprehensive Income", section 3251 "Equity", section 3855 "Financial Instruments, Recognition and Measurement", and section 3865 "Hedging" on January 1, 2007 substantially aligned Canadian GAAP with U.S. GAAP for the treatment of the company's derivative financial instruments. As a result, there were no differences between Canadian and U.S. GAAP at December 31, 2007. For prior year comparative balances disclosed under U.S. GAAP, the company accounted for its derivative financial instruments under the same method as described in note 7.

Under U.S. GAAP, for the year ended December 31, 2006, the company would have recognized $5 million of hedging gains relating to forecasted cash flows in 2007 and 2008. (2005 – $2 million ineffectiveness relating to 2006 and 2007 forecasted cash flows). The net earnings impact of this ineffectiveness was recognized for Canadian GAAP purposes on January 1, 2007 as an adjustment to opening retained earnings.

Accumulated Other Comprehensive Earnings (AOCI) and U.S. GAAP Net Earnings Impacts

A reconciliation of changes in accumulated OCI attributable to derivative hedging activities for the years ended December 31 is as follows:

($ millions)	**2007**	2006
AOCI attributable to derivatives and hedging activities, beginning of the period, net of income taxes of $4 (2006 – $1)	**8**	2
Current period net changes arising from cash flow hedges, net of income taxes of $1 (2006 – $4)	**8**	9
Net hedging losses at the beginning of the period reclassified to earnings during the period, net of income taxes of $2 (2006 – $1)	**(3)**	(3)
AOCI attributable to derivatives and hedging activities, end of period, net of income taxes of $4 (2006 – $4)	**13**	8

For the year ended December 31, 2006, U.S. GAAP net earnings increased by $7 million, net of income taxes of $4 million (2005 – increased net earnings of $55 million, net of income taxes of $28 million) to reflect the impact of ineffectiveness on derivative contracts classified as cash flow hedges.

(b) Stock-Based Compensation

On January 1, 2006, the company adopted the U.S. Financial Accounting Standards Board (FASB) Statement 123(R), "Share-Based Payment", using the modified-prospective approach. FAS 123(R) allows the company to expense common share options issued after January 1, 2003 in a manner consistent with Canadian GAAP. The statement requires the recognition of an expense for employee services received in exchange for an award of equity instruments based on the grant date fair value of the award. The cost is to be recognized over the period for which an employee is required to provide the service in exchange for the award. In addition, the statement requires recognition of compensation expense for the portion of outstanding unvested awards granted prior to the effective date.

Under Canadian GAAP, the company's Performance Share Units (PSUs) are measured using an intrinsic approach, a fair-value technique not permitted under U.S. GAAP. After adoption of FAS 123(R), our PSUs for U.S. GAAP have been measured using a Monte Carlo Simulation approach to determine fair value. The impact on net earnings for the year ended December 31, 2007 is a recovery of previously recognized stock-based compensation expense of $17 million, net of income taxes of $6 million (2006 – $3 million expense, net of income taxes of $1 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 and Comprehensive Income. FAS 123(R) requires the recognition of expense related to the company's pre-2003 options. This resulted in an increase to stock-based compensation expense of $8 million (2006 – $15 million). There was no impact on income taxes.

(c) Accounting for Defined Benefit Pension and Other Post-Retirement Plans

On December 31, 2006, the Company adopted FAS 158, "Employers Accounting for Defined Benefit and Other Post Retirement Plans", requiring the recognition of the over funded or under funded status of a defined benefit post-retirement plan (other than a multi-employer plan) as an asset or liability on the balance sheet. The changes to funded status in the year are recorded through comprehensive income, net of income taxes. The standard was applied prospectively effective December 31, 2006, as retrospective application was not permitted.

For the comparative period, prior to the adoption of FAS 158 on December 31, 2006, recognition of an additional minimum pension liability was required when the accumulated benefit obligation exceeded the fair value of plan assets to the extent that such excess was greater than accrued pension costs otherwise recorded. For the purpose of determining the additional minimum pension liability, the accumulated benefit obligation does not incorporate projections of future compensation increases in the determination of the obligation. No such adjustment was required under Canadian GAAP. As required under FAS 158, the minimum pension liability adjustment recorded in 2006 was reversed in that year.

At December 31, 2006, the company would have recognized a minimum pension liability of $35 million, an intangible asset of $16 million and an accumulated other comprehensive loss of $12 million, net of income taxes of $7 million. Other comprehensive income for the year ended December 31, 2006 would have increased by $39 million, net of income taxes of $20 million (2005 – a decrease of $15 million, net of taxes of $8 million).

Accumulated Other Comprehensive Income (AOCI) and U.S. GAAP Net Earnings Impacts

($ millions)	**2007**	2006
AOCI attributable to defined benefit pension and other post-retirement plans, beginning of period, net of income taxes of $67 million (2006 – $27 million)	**(139)**	(51)
Minimum pension liability (2006 – net of income taxes of $20 million)	**—**	39
Reversal of minimum pension liability upon adoption of FAS 158, (2006 – net of income taxes of $7 million)	**—**	12
Amortization of net actuarial loss, net of income taxes of $10 million	**21**	—
Amortization of past service costs, net of income taxes of $1 million	**(2)**	—
Additions to unamortized net actuarial loss, net of income taxes of $2 million (2006 – $74 million)	**(2)**	(155)
Additions to unamortized past service costs (2006 – net of income taxes of $7 million)	**—**	16
AOCI attributable to defined benefit pension and other post-retirement plans, end of period, net of income taxes of $59 million (2006 – $67 million)	**(122)**	(139)

Total amount included in AOCI expected to be recognized as components of net periodic benefit cost during 2008 are as follows:

Amortization of net actuarial loss	$31 million
Amortization of past service costs	$(3) million

(d) Cumulative Foreign Currency Translation

Prior to the adoption of CICA Section 1530 "Comprehensive Income" on January 1, 2007, under Canadian GAAP, foreign currency gains and losses arising on translation of the company's U.S. based foreign operations were recorded directly to shareholders' equity. Under the new Canadian standard, these foreign currency translation gains and losses are treated as they have been under U.S. GAAP, and included as a component of comprehensive income.

(e) Suspended Exploratory Well Costs

Effective January 1, 2005, Suncor adopted Financial Accounting Standards Board Staff Position 19-1 (FSP 19-1), "Accounting for Suspended Well Costs". FSP 19-1 amended Statement of Financial Accounting Standards No. 19 (FAS 19), "Financial Accounting and Reporting by Oil and Gas Producing Companies", to permit the continued capitalization of exploratory well costs beyond one year if (a) the well found a sufficient quantity of reserves to justify its completion as a producing well and (b) the entity is making sufficient progress assessing the reserves and the economic and operating viability of the project. There were no capitalized exploratory well costs charged to expense upon the adoption of FSP 19-1.

The table below provides details of the changes in the balance of suspended exploratory well costs as well as an aging summary of those costs.

Change in capitalized suspended exploratory well costs

($ millions)	**2007**	2006	2005
Balance, beginning of year	**23**	15	5
Additions pending determination of proved reserves	**14**	21	14
Charged to dry hole expense	**(6)**	—	(2)
Reclassifications to proved properties	**(10)**	(13)	(2)
Balance, end of year	**21**	23	15
Capitalized for a period greater than one year ($ millions)	**7**	2	1
Number of projects that have exploratory well costs capitalized for a period greater than 12 months	**3**	3	2

(f) Accounting for Purchases and Sales Inventory with the Same Counterparty

Emerging Issues Task Force (EITF) Abstract No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty" addresses when it is appropriate to measure purchases and sales of inventory with the same counterparty at fair value and record them in revenues and cost of sales and when they should be recorded as exchanges measured at the book value of the item sold. The EITF concluded that purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another should be combined and recorded as exchanges measured at the book value of the item sold (reported net versus gross). The EITF is effective for transactions entered into subsequent to April 1, 2006.

As required by EITF 04-13, we record certain crude oil, natural gas, petroleum product and chemical purchases and sales entered into contemporaneously with the same counterparty on a net basis within the "purchases of crude oil and products" line in the Consolidated Statements of Earnings and Comprehensive Income. These transactions are undertaken to ensure that the appropriate crude oil is at the appropriate refineries when required and that the appropriate products are available to meet customer demands. These transactions take place in the oil sands and refining and marketing operating segments.

In addition, until 2006, the refining and marketing segment sold finished product and bought coker gas oil as a raw material to be used in the refining process from the same counterparty under terms specified in a single contract. These sales and purchases, as noted in the table below, were recorded at fair value in "revenue" and "purchases of crude oil and products" in the Consolidated Statements of Earnings and Comprehensive Income in accordance with the consensus for Issue 2 in EITF 04-13.

The purchase/sale of contract amounts included in revenue for 2007, 2006 and 2005 are shown below.

($ millions)	**2007**	2006	2005
Consolidated revenues	**17 933**	15 829	11 129
Amounts included in revenues for purchase/sale contracts with the same counterparty (1)	**—**	5	16

(1) Associated costs are in "purchases of crude oil and products".

(g) Research and Development Costs

Under Canadian GAAP, development expenditures are eligible to be capitalized when specific criteria are met. Under FAS 2, "Accounting for Research and Development Costs", development costs are required to be charged to expense when incurred. As a result, $24 million, net of income taxes of $10 million, would have been charged to income during 2007 (2006 – nil; 2005 nil).

(h) Accounting for Uncertainties in Income Taxes

Effective January 1, 2007, the company adopted the FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" (FIN 48). FIN 48 is an interpretation of FASB Statement 109 "Accounting for Income Taxes" and outlines the recognition and related disclosure requirements of uncertain tax positions determined to be more likely than not, defined as greater than 50%, to be sustained on audit.

The adoption of FIN 48 had no impact on net earnings or financial position.

Recently Issued Accounting Standards

In February 2007, FASB issued FAS 159, "The Fair Value Option for Financial Assets and Financial Liabilities". The standard, effective January 1, 2008, affords entities the option to irrevocably choose to measure many financial instruments and certain other items at fair value, at specified election dates. Retrospective application is not permitted. No impact to net earnings or financial position is anticipated.

In September 2006, FASB issued FAS 157 "Fair Value Measurements". The standard, effective January 1, 2008, establishes a recognized framework for measuring fair value, and expands disclosure relating to fair value inputs. No new fair value measurements are required. This Statement is generally to be applied prospectively and does not have an impact on earnings or financial position.

QUARTERLY SUMMARY (unaudited)

FINANCIAL DATA

($ millions, except per share amounts)	For the Quarter Ended Mar 31 2007	June 30 2007	Sept 30 2007	Dec 31 2007	Total Year 2007	For the Quarter Ended Mar 31 2006	June 30 2006	Sept 30 2006	Dec 31 2006	Total Year 2006
Revenues	**3 951**	**4 358**	**4 666**	**4 958**	**17 933**	3 858	4 070	4 114	3 787	15 829
Net earnings (loss)										
Oil Sands	**453**	**419**	**556**	**1 006**	**2 434**	707	1 100	582	394	2 783
Natural Gas	**4**	**(4)**	**—**	**25**	**25**	40	60	12	(6)	106
Refining and Marketing	**99**	**206**	**40**	**—**	**345**	11	116	85	23	235
Corporate and eliminations	**(5)**	**20**	**81**	**(68)**	**28**	(45)	(58)	3	(53)	(153)
	551	**641**	**677**	**963**	**2 832**	713	1 218	682	358	2 971
Per common share										
Net earnings attributable to common shareholders										
– basic	**1.20**	**1.39**	**1.47**	**2.08**	**6.14**	1.56	2.65	1.48	0.78	6.47
– diluted	**1.17**	**1.36**	**1.43**	**2.04**	**6.02**	1.52	2.59	1.45	0.76	6.32
Cash dividends	**0.08**	**0.10**	**0.10**	**0.10**	**0.38**	0.06	0.08	0.08	0.08	0.30
Cash flow from (used in) operations										
Oil Sands	**578**	**576**	**918**	**1 020**	**3 092**	1 205	1 116	924	672	3 917
Natural Gas	**64**	**70**	**47**	**67**	**248**	99	66	68	48	281
Refining and Marketing	**171**	**292**	**83**	**34**	**580**	53	184	162	44	443
Corporate and eliminations	**(23)**	**(54)**	**(21)**	**(17)**	**(115)**	(43)	(46)	(1)	(18)	(108)
	790	**884**	**1 027**	**1 104**	**3 805**	1 314	1 320	1 153	746	4 533

OPERATING DATA

OIL SANDS
(thousands of barrels per day)

	Mar 31 2007	June 30 2007	Sept 30 2007	Dec 31 2007	Total Year 2007	Mar 31 2006	June 30 2006	Sept 30 2006	Dec 31 2006	Total Year 2006
Production [(1)]										
Total production	**248.2**	**202.3**	**239.1**	**252.5**	**235.6**	264.4	267.3	242.8	266.4	260.0
Firebag	**35.3**	**36.2**	**35.8**	**40.4**	**36.9**	27.4	35.0	37.2	35.1	33.7
Sales										
Light sweet crude oil	**105.5**	**100.0**	**99.3**	**102.2**	**101.7**	119.2	124.7	84.9	113.7	110.5
Diesel	**29.5**	**20.3**	**23.9**	**26.0**	**25.0**	35.1	32.9	20.7	24.0	28.2
Light sour crude oil	**112.7**	**84.2**	**94.1**	**118.2**	**102.3**	121.0	99.2	125.8	126.8	118.2
Bitumen	**6.8**	**3.8**	**6.6**	**5.4**	**5.7**	—	8.5	6.6	9.7	6.2
Total sales	**254.5**	**208.3**	**223.9**	**251.8**	**234.7**	275.3	265.3	238.0	274.2	263.1

QUARTERLY SUMMARY (unaudited) (continued)

OPERATING DATA (continued)

($ millions, except per share amounts)	For the Quarter Ended Mar 31 2007	June 30 2007	Sept 30 2007	Dec 31 2007	Total Year 2007	For the Quarter Ended Mar 31 2006	June 30 2006	Sept 30 2006	Dec 31 2006	Total Year 2006
OIL SANDS (continued)										
Average sales price(2) (dollars per barrel)										
Light sweet crude oil	**68.63**	**75.64**	**81.00**	**87.34**	**78.03**	69.00	78.27	78.11	64.51	71.98
Other (diesel, light sour crude oil and bitumen)	**63.62**	**66.74**	**73.76**	**78.48**	**70.86**	63.28	72.75	68.60	57.91	65.17
Total	**65.70**	**71.01**	**76.97**	**82.07**	**74.01**	65.75	75.34	71.99	60.65	68.03
Total(a)	**65.61**	**71.01**	**76.97**	**82.36**	**74.07**	65.75	75.34	71.99	60.65	68.03
Cash operating costs and total operating costs – Total Operations (dollars per barrel sold rounded to the nearest $0.05)										
Cash costs	**21.75**	**28.40**	**23.00**	**24.10**	**24.15**	15.55	15.65	21.00	22.65	18.70
Natural gas	**4.50**	**4.20**	**2.10**	**3.60**	**3.55**	3.45	2.55	2.60	3.00	2.90
Imported bitumen	**0.05**	**0.10**	**—**	**0.20**	**0.10**	0.05	0.10	0.10	—	0.10
Cash operating costs(3)	**26.30**	**32.70**	**25.10**	**27.90**	**27.80**	19.05	18.30	23.70	25.65	21.70
Project start-up costs	**0.10**	**1.15**	**1.10**	**0.55**	**0.95**	0.90	0.10	0.35	0.25	0.40
Total cash operating costs(4)	**26.40**	**33.85**	**26.20**	**28.45**	**28.75**	19.95	18.40	24.05	25.90	22.10
Depreciation, depletion and amortization	**4.45**	**5.85**	**5.70**	**5.60**	**5.40**	3.90	3.80	4.30	4.25	4.05
Total operating costs(5)	**30.85**	**39.70**	**31.90**	**34.05**	**34.15**	23.85	22.20	28.35	30.15	26.15
Cash operating costs and total operating costs – In-Situ Bitumen Production Only (dollars per barrel sold rounded to the nearest $0.05)										
Cash costs	**11.05**	**10.60**	**11.85**	**9.95**	**10.85**	5.70	8.50	5.55	8.05	8.95
Natural gas	**11.05**	**10.60**	**9.10**	**9.15**	**9.90**	7.70	8.15	7.60	9.90	8.35
Cash operating costs(6)	**22.10**	**21.20**	**20.95**	**19.10**	**20.75**	13.40	16.65	13.15	17.95	17.30
Firebag start-up costs	**—**	**—**	**—**	**—**	**—**	8.50	—	—	—	1.70
Total cash operating costs(7)	**22.10**	**21.20**	**20.95**	**19.10**	**20.75**	21.90	16.65	13.15	17.95	19.00
Depreciation, depletion and amortization	**5.35**	**5.75**	**6.70**	**6.80**	**6.20**	6.90	3.75	5.55	6.20	5.55
Total operating costs(8)	**27.45**	**26.95**	**27.65**	**25.90**	**26.95**	28.80	20.40	18.70	24.15	24.55

QUARTERLY SUMMARY (unaudited) (continued)

OPERATING DATA (continued)

($ millions, except per share amounts)	For the Quarter Ended Mar 31 2007	June 30 2007	Sept 30 2007	Dec 31 2007	Total Year 2007	For the Quarter Ended Mar 31 2006	June 30 2006	Sept 30 2006	Dec 31 2006	Total Year 2006
NATURAL GAS										
Gross production[b]										
Natural gas (millions of cubic feet per day)	**191**	**191**	**193**	**210**	**196**	196	189	191	192	191
Natural gas liquids and crude oil (thousands of barrels per day)	**3.1**	**3.0**	**3.1**	**3.2**	**3.1**	3.2	3.5	2.8	2.6	3.0
Total gross production (thousands of barrels of oil equivalent per day)	**34.9**	**34.9**	**35.2**	**38.2**	**35.8**	35.9	35.1	34.6	34.7	34.8
Total gross production (millions of cubic feet equivalent per day)	**209**	**209**	**211**	**229**	**215**	215	211	208	208	209
Average sales price[2]										
Natural gas (dollars per thousand cubic feet)	**7.01**	**6.85**	**5.39**	**6.08**	**6.32**	9.03	6.38	6.33	6.55	7.15
Natural gas[a] (dollars per thousand cubic feet)	**7.14**	**6.83**	**5.14**	**6.02**	**6.27**	8.75	6.22	6.13	6.40	6.95
Natural gas liquids and crude oil – conventional (dollars per barrel)	**56.69**	**51.21**	**58.11**	**60.31**	**56.64**	53.89	63.75	61.07	45.55	51.93
REFINING AND MARKETING										
Refined product sales (thousands of cubic metres per day)	**31.6**	**34.6**	**35.1**	**32.8**	**33.5**	26.6	31.6	31.4	29.1	29.5
Utilization of refining capacity (%)	**97**	**108**	**102**	**87**	**98**	74	96	95	76	85

(a) Excludes the impact of hedging activities.

(b) Currently natural gas production is located in the Western Canada Sedimentary Basin.

Definitions

(1) Total production – Total production includes total production from both mining and in-situ operations.

(2) Average sales price – This operating statistic is calculated before royalties and net of related transportation costs (including or excluding the impact of hedging activities as noted).

(3) Cash operating costs – Total operations – Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense, taxes other than income taxes and the cost of bitumen imported from third parties. Per barrel amounts are based on total production volumes. For a reconciliation of this non-GAAP financial measure see Management's Discussion and Analysis.

(4) Total cash operating costs – Total operations – Include cash operating costs – Total operations as defined above and cash start-up costs. Per barrel amounts are based on total production volumes.

(5) Total operating costs – Total operations – Include total cash operating costs – Total operations as defined above and non-cash operating costs. Per barrel amounts are based on total production volumes.

(6) Cash operating costs – In-situ bitumen production – Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense and taxes other than income taxes. Per barrel amounts are based on in-situ production volumes only.

(7) Total cash operating costs – In-situ bitumen production – Include cash operating costs – In-situ bitumen production as defined above and cash start-up costs for in-situ operations. Per barrel amounts are based on in-situ production volumes only.

(8) Total operating costs – In-situ bitumen production – Include total cash operating costs – In-situ bitumen production as defined above and non-cash operating costs. Per barrel amounts are based on in-situ production volumes only.

Metric conversion

Crude oil, refined products, etc. – $1m^3$ (cubic metre) = approximately 6.29 barrels
Natural gas – $1m^3$ (cubic metre) = approximately 35.49 cubic feet

FIVE-YEAR FINANCIAL SUMMARY (unaudited)

($ millions, except for ratios)	**2007**	2006	2005	2004	2003
Revenues					
Oil Sands	**6 775**	7 407	3 965	3 640	3 101
Natural Gas	**553**	578	679	567	512
Refining and Marketing	**11 173**	8 593	6 984	4 995	3 451
Corporate and eliminations	**(568)**	(749)	(499)	(497)	(453)
	17 933	15 829	11 129	8 705	6 611
Net earnings (loss)					
Oil Sands	**2 434**	2 783	957	956	892
Natural Gas	**25**	106	155	114	120
Refining and Marketing	**345**	235	174	107	70
Corporate and eliminations	**28**	(153)	(128)	(101)	18
	2 832	2 971	1 158	1 076	1 100
Cash flow from (used in) operations					
Oil Sands	**3 092**	3 917	1 916	1 717	1 780
Natural Gas	**248**	281	412	314	296
Refining and Marketing	**580**	443	363	204	158
Corporate and eliminations	**(115)**	(108)	(215)	(222)	(194)
	3 805	4 533	2 476	2 013	2 040
Capital and exploration expenditures					
Oil Sands	**4 431**	2 463	1 948	1 119	953
Natural Gas	**531**	458	363	279	184
Refining and Marketing	**376**	665	779	418	153
Corporate	**77**	27	63	31	32
	5 415	3 613	3 153	1 847	1 322
Total assets	**24 167**	18 759	15 126	11 749	10 463
Ending capital employed[a]					
Short-term and long-term debt, less cash and cash equivalents	**3 248**	1 849	2 868	2 134	2 551
Shareholders' equity	**11 613**	8 952	5 996	4 874	3 858
	14 861	10 801	8 864	7 008	6 409
Less capitalized costs related to major projects in progress	**(4 148)**	(2 649)	(2 938)	(1 467)	(1 122)
	10 713	8 152	5 926	5 541	5 287
Total Suncor employees (number at year-end)	**6 465**	5 766	5 152	4 605	4 231

FIVE-YEAR FINANCIAL SUMMARY (unaudited) (continued)

($ millions, except for ratios)	**2007**	2006	2005	2004	2003
Dollars per common share					
Net earnings attributable to common shareholders	**6.14**	6.47	2.54	2.38	2.45
Cash dividends	**0.38**	0.30	0.24	0.23	0.1925
Cash flow from operations	**8.25**	9.87	5.43	4.44	4.54
Ratios					
Return on capital employed (%) [(a), (b)]	**28.3**	40.7	19.8	19.0	18.8
Return on capital employed (%) [(c)]	**20.7**	30.5	14.4	16.1	16.3
Return on shareholders' equity (%) [(d)]	**27.5**	39.7	21.3	24.6	32.9
Debt to debt plus shareholders' equity (%) [(e)]	**24.7**	20.9	33.6	31.3	43.2
Net debt to cash flow from operations (times) [(f)]	**0.9**	0.4	1.2	1.1	1.3
Interest coverage – cash flow basis (times) [(g)]	**22.2**	30.5	16.9	13.7	11.9
Interest coverage – net earnings basis (times) [(h)]	**17.7**	25.5	12.5	10.8	10.5

(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, at the beginning and end of the year, divided by two, less average capitalized costs related to major projects in progress (as applicable). Return on capital employed (ROCE) for Suncor operating segments presented in the Quarterly Operating Summary is calculated in a manner consistent with consolidated ROCE. For a detailed annual reconciliation of this non-GAAP financial measure see page 46 of MD&A.

(c) 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.

(d) 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.

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

(f) Short-term debt plus long-term debt less cash and cash equivalents; divided by cash flow from operations for the year then ended.

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

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

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 2007	**June 30 2007**	**Sept 30 2007**	**Dec 31 2007**	Mar 31 2006	June 30 2006	Sept 30 2006	Dec 31 2006
Share ownership								
Average number outstanding, weighted monthly (thousands) [(a)]	**460 074**	**460 422**	**460 789**	**461 187**	458 230	458 596	458 859	459 069
Share price (dollars)								
Toronto Stock Exchange								
High	**92.85**	**99.70**	**101.55**	**109.47**	93.85	102.18	97.12	95.00
Low	**79.66**	**87.58**	**88.72**	**91.25**	75.58	75.00	71.18	72.26
Close	**87.85**	**95.96**	**94.46**	**107.91**	89.63	90.34	80.19	91.79
New York Stock Exchange – US$								
High	**77.79**	**93.52**	**100.11**	**117.98**	82.15	89.86	86.78	82.08
Low	**67.78**	**75.71**	**82.37**	**91.40**	64.00	67.36	63.77	64.06
Close	**76.35**	**89.92**	**94.81**	**108.73**	77.02	81.01	72.05	78.91
Shares traded (thousands)								
Toronto Stock Exchange	**109 485**	**87 784**	**99 701**	**100 233**	107 797	101 626	106 348	99 704
New York Stock Exchange	**97 383**	**71 365**	**65 133**	**58 157**	114 031	116 492	100 714	94 676
Per common share information (dollars)								
Net earnings attributable to common shareholders	**1.20**	**1.39**	**1.47**	**2.08**	1.56	2.65	1.48	0.78
Cash dividends	**0.08**	**0.10**	**0.10**	**0.10**	0.06	0.08	0.08	0.08

(a) The company had approximately 2,387 holders of record of common shares as at January 31, 2008.

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.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited)

	2007	2006	2005	2004	2003
OIL SANDS					
Production (thousands of barrels per day)	**235.6**	260.0	171.3	226.5	216.6
Sales (thousands of barrels per day)					
Light sweet crude oil	**101.7**	110.5	73.3	114.9	112.3
Diesel	**25.0**	28.2	15.6	27.9	26.3
Light sour crude oil	**102.3**	118.2	59.8	75.1	73.3
Bitumen	**5.7**	6.2	16.6	8.4	6.4
	234.7	263.1	165.3	226.3	218.3
Average sales price (dollars per barrel)					
Light sweet crude oil	**78.03**	71.98	49.93	45.60	40.26
Other (diesel, light sour crude oil and bitumen)	**70.86**	65.17	56.90	39.13	33.93
Total	**74.01**	68.03	53.81	42.28	37.19
Total [a]	**74.07**	68.03	62.68	49.78	40.22
Cash operating costs – total operations [b]	**27.80**	21.70	24.55	15.15	13.80
Total cash operating costs – total operations [b]	**28.75**	22.10	24.65	15.45	13.80
Total operating costs – total operations [b]	**34.15**	26.15	29.95	19.05	17.15
Cash operating costs – in-situ bitumen production [b], [e]	**20.75**	17.30	22.20	22.05	—
Total cash operating costs – in-situ bitumen production [b], [e]	**20.75**	19.00	23.20	28.90	—
Total operating costs – in-situ bitumen production [b], [e]	**26.95**	24.55	28.10	34.90	—
Ending capital employed excluding major projects in progress	**6 541**	5 015	4 436	4 088	4 007
Return on capital employed (%) [c]	**42.6**	53.5	22.4	22.3	21.1
Return on capital employed (%) [d]	**27.6**	40.1	16.0	18.2	17.7

(a) Excludes the impact of hedging activities.

(b) Dollars per barrel rounded to the nearest $0.05. See definitions on page 93.

(c) See definitions on page 95.

(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) In-situ bitumen production commenced commerical operations on April 1, 2004.

	2007	2006	2005	2004	2003
NATURAL GAS					
Production					
Natural gas (millions of cubic feet per day)					
Gross	**196**	191	190	200	187
Net [(a)]	**153**	141	137	147	142
Natural gas liquids and crude oil (thousands of barrels per day)					
Gross	**3.1**	3.0	3.2	3.5	3.7
Net [(a)]	**2.4**	2.3	2.6	2.6	2.8
Total (thousands of boe [(b)] per day)					
Gross	**35.8**	34.8	34.8	36.8	34.9
Net [(a)]	**27.9**	25.8	25.3	27.1	26.4
Total (millions of cubic feet equivalent per day)					
Gross	**215**	209	209	221	209
Net [(a)]	**167**	155	152	163	158
Average sales price					
Natural gas (dollars per thousand cubic feet)	**6.32**	7.15	8.57	6.70	6.42
Natural gas (dollars per thousand cubic feet) [(c)]	**6.27**	6.95	8.59	6.73	6.42
Natural gas liquids and crude oil – conventional (dollars per barrel)	**56.64**	51.93	54.24	44.99	37.67
Ending capital employed	**1 153**	857	562	447	400
Return on capital employed (%) [(g)]	**2.5**	14.9	30.7	26.9	29.2
Undeveloped landholdings [(d)]					
Oil and gas (millions of acres)					
Western Canada					
Gross	**1.3**	1.2	0.6	0.7	0.5
Net [(e)]	**0.7**	0.7	0.4	0.5	0.4
International					
Gross	**0.1**	0.1	0.4	0.7	0.9
Net [(e)]	**—**	—	0.2	0.4	0.2
Net wells drilled [(f)]					
Exploratory					
Oil	**—**	—	—	—	—
Gas	**7**	3	8	5	2
Dry	**6**	5	4	5	31
Development					
Oil	**1**	1	1	—	1
Gas	**14**	13	18	16	16
Dry	**3**	4	3	—	4
	31	26	34	26	54

(a) Net of royalties.
(b) Barrel of oil equivalent – converts natural gas to oil on the approximate energy equivalent basis that 6,000 cubic feet equals one barrel of oil.
(c) Excludes the impact of hedging activities.
(d) Metric conversion: Landholdings – 1 hectare = approximately 2.5 acres.
(e) Our interest in the undeveloped landholdings.
(f) Excludes interests in eight net exploratory wells and eight net development wells in progress at the end of 2007.
(g) See definitions on page 95.

	2007	2006	2005	2004	2003
REFINING AND MARKETING					
Refined product sales					
(thousands of cubic metres per day)					
Transportation fuels					
Gasoline					
Retail [a]	**5.2**	5.3	5.2	5.3	5.1
Other	**11.6**	10.6	10.1	7.9	7.7
Distillate	**10.6**	8.5	8.3	6.7	6.5
Total transportation fuel sales	**27.4**	24.4	23.6	19.9	19.3
Petrochemicals	**0.9**	0.9	0.7	0.8	0.8
Asphalt	**1.7**	1.2	1.6	1.5	1.7
Other	**3.5**	3.0	3.0	2.5	2.3
Total refined product sales	**33.5**	29.5	28.9	24.7	24.1
Crude oil supply and refining					
Processed at refineries					
(thousands of cubic metres per day)	**25.1**	21.7	22.7	19.9	19.9
Utilization of refining capacity (%)	**98**	85	97	96	96
Ending capital employed excluding major projects in progress	**2 270**	1 818	796	736	820
Return on capital employed (%) [b]	**16.8**	20.4	22.2	13.0	10.7
Return on capital employed (%) [b, c, e]	**14.5**	12.5	13.8	12.0	10.7
Retail outlets [d] (number at year-end)	**419**	417	417	421	422

(a) Excludes sales through joint venture interests.

(b) See definitions on page 95.

(c) 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.

(d) Sunoco-branded and Phillips 66®-branded service stations, other private brands managed by refining and marketing, and refining and marketing's interest in service stations managed through joint ventures.

(e) For 2003, return on capital employed calculated for Canadian operations only (U.S. operations acquired during 2003).

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 2007, Suncor paid an aggregate dividend of $0.38 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.

Annual Meeting

Suncor's Annual and Special meeting of shareholders will be held at 10:30 a.m. MT on April 24, 2008, at the Metropolitan Centre, 333 Fourth Avenue S.W., 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

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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.

There are no significant differences between Suncor's governance practices and those prescribed by the NYSE other than requirements applicable to equity compensation plans. A comprehensive description of Suncor's governance practices 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 partner in Kanetax Energy Inc., Tenax Energy Inc. and a director of Winalta Homes Inc. He is active with several charitable organizations including Hull Family Services and the Canadian Aboriginal Professional Association. He is also a member of the Board of Governors for the Northern Alberta Institute of Technology and the National Aboriginal Economic Development Board.

Brian A. Canfield(1)(2)
(independent)
Point Roberts, Washington
Director since 1995
Brian Canfield is the chairman of TELUS Corporation, a telecommunications company. Mr. Canfield is also a director and chairman of the governance committee of the Canadian Public Accountability Board. 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.

Bryan P. Davies(3)(4)
(independent)
Toronto, Ontario
Director 1991 to 1996 and since 2000
Bryan Davies is chairman of the Canada Deposit Insurance Corporation. He is also a director of the General Insurance Statistical Agency and is past superintendent of the Financial Services Commission of Ontario. Prior to that, he was senior vice president, regulatory affairs with the Royal Bank Financial Group. Mr. Davies is also active with a number of not-for-profit charitable organizations.

Brian A. Felesky(1)(4)
(independent)
Calgary, Alberta
Director since 2002
Brian Felesky is counsel to the law firm of Felesky Flynn LLP in Calgary, Alberta. Mr. Felesky also serves as a director on the board and is chair of the audit committee of Epcor Power LP. He is also a member of the board of Precision Drilling Trust and Resin Systems Inc. Mr. Felesky is actively involved in not-for-profit and charitable organizations. He is the co-chair of Homefront on Domestic Violence, vice chair of the Canada West Foundation, member of the senate of Athol Murray College of Notre Dame and board member of the Calgary Stampede Foundation. Mr. Felesky is a Queen's Counsel and member of the Order of Canada.

John T. Ferguson(2)(3)
(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 director of the C.D. Howe Institute, 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 also a fellow of the Alberta Institute of Chartered Accountants and of the Institute of Corporate Directors.

W. Douglas Ford(1)(2)
(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 the company 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 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 U.S. offshore and onshore drilling company Transocean. In 2006, he was selected to serve as a member of the North American Competitiveness Council. In 2007, he became a member of the Calgary Committee to End Homelessness and is currently chair of the 2008 Governor General's Canadian Leadership Conference. Mr. George was named a member of the Order of Canada in 2007.

John R. Huff(2)(3)
(independent)
Houston, Texas
Director since 1998

John Huff is chairman of Oceaneering International Inc., an oil field services company. He is also a director of BJ Services Company, KBR and Rowan Companies Inc. Mr. Huff is a member of the National Petroleum Council, the Houston Museum of Natural Science and St. Luke's Episcopal Hospital System in Houston.

M. Ann McCaig(3)(4)
(independent)
Calgary, Alberta
Director since 1995

Ann McCaig is actively involved with charitable and community activities. She is past co-chair of the Alberta Children's Hospital Foundation which raised $52 million for the new state-of-the-art pediatric facility in Calgary. She is currently chair of the Alberta Adolescent Recovery Centre, a trustee of the Killam Estate, chair of the Calgary Health Trust, a director of the Calgary Stampede Foundation and honourary chair of the Alberta Bone and Joint Institute. She is also chancellor emeritus of the University of Calgary and a member of the Order of Canada.

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 serves on the board of Shaw Communications Inc. and is an advisor to CRA International. 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.

Eira M. Thomas(1)(4)
(independent)
West Vancouver, British Columbia
Director since 2006

Eira Thomas has been chief executive officer of Stornoway Diamond Corporation, a mineral exploration company, 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. and Fortress Minerals 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) Board Policy, Strategy Review & Governance Committee
(3) Human Resources and Compensation Committee
(4) Environment, Health & Safety Committee

CORPORATE OFFICERS(1)(2)

Richard L. George
President and Chief Executive Officer

J. Kenneth Alley
Senior Vice President and
Chief Financial Officer

M. (Mike) Ashar
Executive Vice President,
Strategic Growth and Energy Trading

Kirk Bailey
Executive Vice President,
Oil Sands

David W. Byler
Executive Vice President,
Natural Gas and Renewable Energy

Bart W. Demosky
Vice President and Treasurer

Terrence J. Hopwood
Senior Vice President and General Counsel

Sue Lee
Senior Vice President,
Human Resources and Communications

Kevin D. Nabholz
Executive Vice President,
Major Projects

Janice B. Odegaard
Vice President,
Associate General Counsel and Corporate Secretary

Thomas L. Ryley
Executive Vice President,
Refining and Marketing

Jay Thornton
Senior Vice President,
Business Integration

Steven W. Williams
Chief Operating Officer

(1) Offices shown are positions held by the officers in relation to businesses of Suncor Energy Inc. and its subsidiaries. On a legal entity basis, Mr. Ashar is president of Suncor Energy Marketing Inc. and Mr. Ryley is president of Suncor Energy Products Inc., each of which are Suncor's Canada-based downstream subsidiaries; and Mr. Nabholz, Ms. Lee and Mr. Thornton are officers of Suncor Energy Services Inc., which provides major projects management, human resources and communication, business integration and other shared services to the Suncor group of companies.

(2) This information reflects the positions of officers at December 31, 2007.

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