

# Clear



PETRO-CANADA'S 2006 STRATEGIC OVERVIEW REPORT



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*Please refer to the forward-looking information statements and a description of financial data that does not conform with Canadian generally accepted accounting principles (GAAP) on the inside back cover of this document.*

# Clear. Capable. Committed.



Petro-Canada is one of Canada’s largest oil and gas companies. The Company creates value by responsibly developing energy resources and providing world class petroleum products and services.

# About Petro-Canada

With a market capitalization around \$23 billion,<sup>1</sup> Petro-Canada is a mid-sized energy company. We can take on big projects, but smaller ones can also positively impact our results.

Our roots are in Canada, a country rich in resources and part of the large and growing North American market. We have a long history of developing energy resources and we're known for having a co-operative approach to doing business globally. More than 5,000 employees work on our behalf around the world.



<sup>1</sup> At February 12, 2007.

We're financially strong and disciplined. In 2006, our operating earnings from continuing operations were \$1.8 billion and we generated \$3.7 billion in cash flow. This allowed us to fund a \$3.5<sup>1</sup> billion capital program and return cash to shareholders through dividends and a share buyback program.

<b>Financial and Operating Highlights</b>	<b>2006</b>	<b>2005</b>	<b>2004</b>	<b>2003</b>	<b>2002</b>
Operating earnings from continuing operations <i>(\$ millions)</i>	<b>1,802</b>	2,148	1,829	1,267	997
Cash flow from continuing operating activities before changes in non-cash working capital <i>(\$ millions)</i>	<b>3,687</b>	3,787	3,425	3,042	2,063
Expenditures on property, plant and equipment and exploration from continuing operations <i>(\$ millions)</i>	<b>3,434</b>	3,560	3,893	2,142	1,685
Debt-to-debt plus equity <i>(%)</i> <sup>1</sup>	<b>21.7</b>	23.5	22.8	22.7	35.1
Debt-to-cash flow <i>(times)</i>	<b>0.8</b>	0.8	0.8	0.7	1.5
Operating return on capital employed <i>(%)</i> <sup>1</sup>	<b>15.0</b>	19.8	18.8	16.1	14.5
Upstream proved reserves <i>(millions of barrels of oil equivalent – MMboe)</i> <sup>2, 3, 4</sup>	<b>1,274</b>	1,232	1,213	1,220	1,290

1 Includes results from discontinued operations.

2 Company proved reserves include reserves from oil and gas activities and oil sands mining. Please refer to the legal notice and forward-looking statements at the end of this report for further explanation.

3 Before royalties.

4 Where the term barrels of oil equivalent (boe) is used in this document, it may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet (Mcf); one barrel (bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In addition to our community investments in the areas of education, environment and local community support, we're proud to be a National Partner to the Vancouver 2010 Olympic and Paralympic Winter Games.

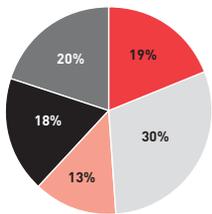
So that is who we are – a successful energy company, based in Canada and operating responsibly around the world.

1 Includes amounts for deferred charges and other assets, and discontinued operations.

# Our businesses

## Cash Flow From Continuing Operating Activities Before Changes In Non-Cash Working Capital<sup>1</sup>

For the year ended December 31, 2006 (%)  
Total: \$3,687 million



- North American Natural Gas
- East Coast Oil
- Oil Sands
- International
- Downstream

<sup>1</sup> Does not include negative cash flow of \$218 million for Shared Services.

In prior years, most of our cash flow came from our North American Natural Gas and East Coast Oil businesses. In 2006, lower gas prices impacted North American Natural Gas cash flow. In the future, as our Downstream, International and Oil Sands businesses continue to grow, it is expected they will contribute greater cash flow.

We believe our integrated portfolio of businesses gives us strength. Our diverse businesses provide more stability in changing business environments, allow us greater access to growth opportunities and create value through the integration between businesses.

## UPSTREAM

In 2006, we had four upstream businesses: North American Natural Gas, East Coast Oil, Oil Sands and International. Each has a different area of focus – from the resources they develop to the processes they use and the locations in which they operate. In 2006, these businesses produced 345,000 barrels of oil equivalent per day (boe/d) net from continuing operations. In 2007, we expect a 15% increase in production, with a forecast in the range of 390,000 boe/d to 420,000 boe/d net. In 2007, we also consolidated East Coast Oil and the International businesses to leverage and grow the capabilities of similar operations.



In our **North American Natural Gas** business, we explore for and produce natural gas, crude oil and natural gas liquids (NGL) in Western Canada and the U.S. Rockies. In 2006, we produced 616 million cubic feet per day of natural gas (MMcf/d) (102,700 boe/d) net and 14,200 barrels per day (b/d) net of crude oil and NGL. As the western Canadian basin matures, our focus is shifting to unconventional production and long-term supply opportunities in Alaska and the Mackenzie Delta/Corridor, as well as liquefied natural gas (LNG) projects.

In **East Coast Oil**, our participation in major offshore projects in Eastern Canada contributed production of 72,700 boe/d net in 2006. This production came from Terra Nova, (operator and 34% interest), Hibernia (20% interest) and White Rose (27.5% interest). At Terra Nova and White Rose, the oil flows from wells on the seabed into Floating Production Storage and Offloading (FPSO) vessels. Hibernia produces oil from a concrete gravity base structure. The East Coast Oil business goal is to sustain profitable production by extending existing reservoirs and tying in satellite fields.



- Operated
- Proposed/non-operated
- Non-operated

In our **Oil Sands** business, we have both mining and *in situ* assets. In mining, our 12% interest in Syncrude delivered 31,000 b/d in 2006. As a 55% owner and operator of the proposed Fort Hills Oil Sands mining project, we have regulatory approval to produce up to 190,000 b/d of bitumen, with initial production in 2011. We plan to build an upgrader near Edmonton to process the bitumen. Our 100% owned and operated *in situ* MacKay River project produced 21,200 b/d in 2006 and we have plans to add another 40,000 b/d of capacity by the end of the decade.



- Directly operated
- Non-operated

The **International** business operates in Northwest Europe, North Africa/Near East and Northern Latin America. The business is growing by optimizing existing assets, implementing a balanced exploration program and pursuing business development opportunities. The Northwest Europe region produced 43,700 boe/d net in 2006 and growth is expected in 2007 as Buzzard (29.9% interest) ramps up. In the North Africa/Near East region (Libya), we produced 49,400 boe/d net from continuing operations in 2006. In Northern Latin America, a 17.3% interest in a natural gas development in Trinidad and Tobago produced 63 MMcf/d (10,500 boe/d net) in 2006. We also have an interest in an oil project in Venezuela. Our exploration program spans all three regions.



- Petro-Canada assets
- Petro-Canada International offices

## DOWNSTREAM

Petro-Canada is Canada's second largest downstream company based on sales of refined petroleum products. Our refineries in Edmonton, Alberta and Montreal, Quebec accounted for 13% of Canada's refining capacity in 2006. We are currently converting our Edmonton refinery to process 100% bitumen-based feedstock and are considering the potential for a new coker at the Montreal refinery. We are known as "Canada's Gas Station," selling approximately 16% of all petroleum products sold in Canada in 2006. At our Mississauga, Ontario lubricants plant, where we produce pure lubricating oil-based stocks and other specialized products, we increased capacity by 25% in 2006.



- Petro-Canada refinery
- Petro-Canada lubricants plant

# Message from the President



Ron Brenneman,  
President and  
Chief Executive Officer

This year's annual report has the theme "clear, capable and committed" for three reasons. First, our plans for the future are clear, with a well-defined strategy and visible next steps. Second, Petro-Canada is a capable company, able to execute plans and deliver value. And last, but not least, we are committed to "doing the right thing," which means making sure our actions reflect a principled company.

Since 2000, our strategy has been clear – to profitably grow and improve the quality of our operations. This clarity is important because it focuses the organization and allows our stakeholders to understand and track our progress.

From a growth perspective, we've assembled a group of high quality projects and assets that we believe will provide us with growing cash flow and earnings over time. In 2007, we expect a 15% increase in upstream production as we see the full-year impact of projects that came on-stream in 2006 and the ramp up of production from our Buzzard interest in the North Sea.

We also eagerly await the results of our largest exploration program to date. We plan to drill up to 20 wells in Alaska and in our International business.

Longer term, we're planning to bring on five major projects over the next few years. In order of expected on-stream dates, they are the Edmonton refinery conversion project (2008), Montreal refinery coker (2009), Syria gas project (2010), MacKay River expansion (2010) and Fort Hills (2011). With such a strong lineup, we're going to narrow down our list of other opportunities in 2007. We will proceed with only those that will make a material difference and that we're sure we can execute. Petro-Canada's growth will become clearer as our projects advance, our exploration results come in and we focus our portfolio.

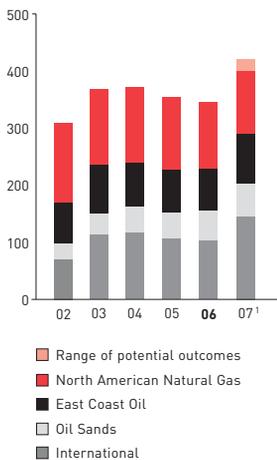
From an operational perspective, our strategy is to continue to ensure our business is run safely, reliably and efficiently. We had a number of successes in 2006. First and foremost, our total recordable injury frequency went down by 25%, putting our safety performance in line with pacesetter companies. This is a tremendous accomplishment considering how large our projects were in 2006 and how many new employees and contractors we had on our sites.

Most of our operated facilities also ran reliably. Western Canada natural gas processing facilities operated at reliability rates of more than 98%. The MacKay River *in situ* plant operated at 92% reliability. In the Downstream, our two refineries had a combined reliability index of 95 and, while the fire at our lubricants plant early in the year was a setback, the facility operated well for the remainder of the year. The disappointment from an operational perspective was Terra Nova, with the early shutdown and the extension of our planned turnaround. We have a specific

## Production from Continuing Operations

In 2007, upstream production is expected to increase by about 15%, reflecting the full-year impact of projects that came on-stream in 2006 and the ramp up of production from our Buzzard interest in the North Sea.

*(Thousands of barrels of oil equivalent – Mboe/d, net before royalties)*



1 As per the Company's forecast.

plan to get Terra Nova reliability into the 90% range. We are also combining our East Coast Oil and International businesses to leverage and grow the capabilities of similar operations.

As with growth, our operational goals are also clear. We want to be among the first quartile performers when it comes to the reliability, safety and efficiency of our operated and non-operated facilities.

In 2006, we brought on a number of major projects. In the Downstream, we successfully converted our refineries to produce cleaner burning fuels and we expanded our lubricants plant by 25%. In the upstream, we attained first oil at De Ruyter, our second operated platform in the North Sea. These major operated projects, totalling some \$1.7 billion of capital, were brought on-stream on time and on budget.

As we look to the future, a key to our success will be building on organizational capability to execute the major projects in our plan. To retain and attract quality people, we formed a dedicated recruiting team to attract more than 650 employees in 2006. As well, our attrition rate in 2006 was below the industry average. Much of this success can be attributed to the breadth of opportunity and learning we can offer employees and our reputation as a principled company.

This naturally brings us to our last theme: our commitment to do the right thing. We continue to use our Principles for Responsible Investment and Operations to guide our actions in the areas of business conduct, community participation, environmental protection, and working conditions and human rights.

Some highlights in 2006 included expanding our training on anticorruption and antitrust laws, as well as our own Code of Business Conduct. We also reviewed how we work with stakeholders and invest in communities to make sure these interactions reflect the next stage of our business growth. We began making sizable investments in educational institutions in Canada in 2006 because we believe supporting education is a key way we can help address the shortage of skilled labour in our industry, particularly in Canada.

We also do our best to reduce the impact our operations have on the environment. In 2006, we reduced our environmental exceedances by more than 20% and began developing systems to better track our performance and guide our decision-making in the critical areas of air pollutants and water use.

Our proposition for investors is to deliver integrated value from a diverse resource base. We can deliver on this promise if we focus on execution, both in our day-to-day operations and as we advance growth projects.

Execution is also important to customers who want innovative service offerings and value for their dollar. I expect that gasoline pricing will continue to be volatile (reflecting worldwide oil prices) and competitive (as retailers shrink gasoline margins in favour of greater focus on non-petroleum revenue). However, I think you are going to be pleased with some of our new products and services as we introduce state-of-the-art car washes, new concepts in food services and the next generation of lubricants.

Communities will also be keenly interested in our execution, watching our approach to working with them as we bring on new projects. We welcome this partnership and commit to working with you to share benefits and to minimize our impact on land, air and water. And, of course, our employees are key to how well we execute our plans. Our plans for the future are robust and achievable, so employees can expect some exciting years of learning and opportunity.

In closing, our road map to success is clear. We have assembled a capable organization to execute our plans and our commitment to act with integrity will not waiver. I thank all of you who participated in Petro-Canada's story in 2006 and we look forward to having you join us again in 2007.

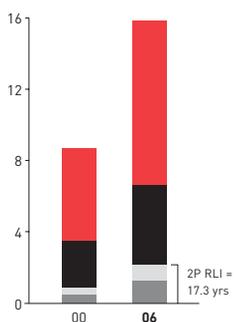


Ron Brenneman  
President and Chief Executive Officer

#### Total Upstream Resources<sup>1</sup>

Petro-Canada has built a portfolio of nearly 16 billion boes of total resources. Only a small portion of this is developed as proved plus probable (2P) reserves, with a reserves life index (RLI) of 17.3 years. Approximately two-thirds of the total resources are located in Alberta's oil sands.

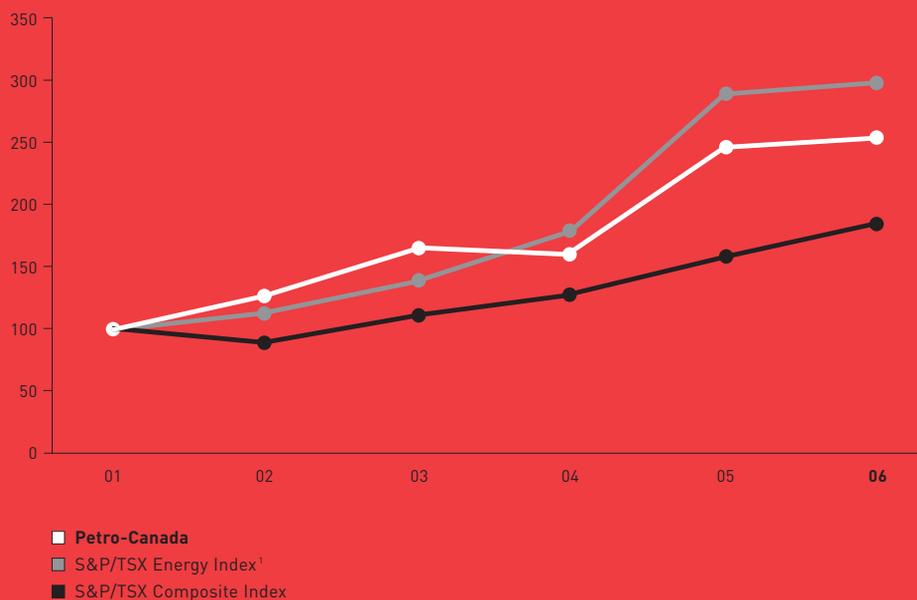
(Billion barrels of oil equivalent)



- Oil Sands resources
- Other resources
- Probable reserves
- Proved reserves

<sup>1</sup> Total resources equals total Company reserves plus resources. Please refer to the legal notice – forward-looking statements at the end of this report for further explanation.

### Five-Year Share Price Performance



<sup>1</sup> No dividends for S&P/TSX Energy Index.

Petro-Canada is an independent company traded on the Toronto and New York Stock Exchanges. While we were incorporated as a Crown corporation back in 1975, privatization began in 1991 and the Government of Canada sold its last shares in Petro-Canada in 2004.

This graph charts performance of an investment in Petro-Canada’s common shares against each of the Standard & Poor’s (S&P)/Toronto Stock Exchange (TSX) Composite Index and the S&P/TSX Energy Index, assuming an investment of \$100 on December 31, 2001 and accumulation and reinvestment of all dividends paid from the date through December 31, 2006.

From 2001 to 2003, Petro-Canada outperformed its peer group. From 2004 to 2006, we underperformed relative to our peers. Looking forward, we expect upstream production to grow by about 15% in 2007. Beyond that, we are developing five major projects over the next several years.

# Clear

on where we're going and how we'll get there

Whether you are an investor, employee, customer, partner or community member, Petro-Canada's goal is to provide you with value. We recognize that value comes in different forms – superior returns, challenging work, excellent service and respectful relationships. We can provide this kind of value because of our diverse businesses, our consistent business strategy and our plans for the future.

## 5

### major projects over the next few years

- Edmonton refinery conversion (2008)
- Montreal refinery coker (2009)
- Syria gas project (2010)
- MacKay River expansion (2010)
- Fort Hills (2011)

As a medium-sized, integrated Canadian energy company, we're well positioned for success. Our diverse businesses give us flexibility to take on growth projects and offset the ups and downs of rapidly changing business environments. As a Canadian-based company, we are ideally located near some of the largest energy resources in the world, as well as nearby demand from U.S. consumers. We are experienced energy developers and are known globally for our collaborative approach to getting the job done.

Since 2000, our strategy has been clearly defined: to deliver profitable growth and improve base business profitability. We've made a lot of progress, operating a suite of quality assets and developing a list of attractive projects for the future. In 2007, our plan is to increase our upstream production by 15%, continue to operate our assets safely, reliably and efficiently, and advance our growth projects.



Buzzard platform in the United Kingdom (U.K.) sector of the North Sea



U.S. Rockies coal bed methane (CBM) operations



The future site of the Fort Hills mine



The Edmonton refinery

# Delivering profitable growth with a focus on long-life assets

Growth is fundamental to our long-term success. Our diverse resource base provides us with greater access to new opportunities. In developing these opportunities, our objective is to increase the proportion of long-life resources in the portfolio.

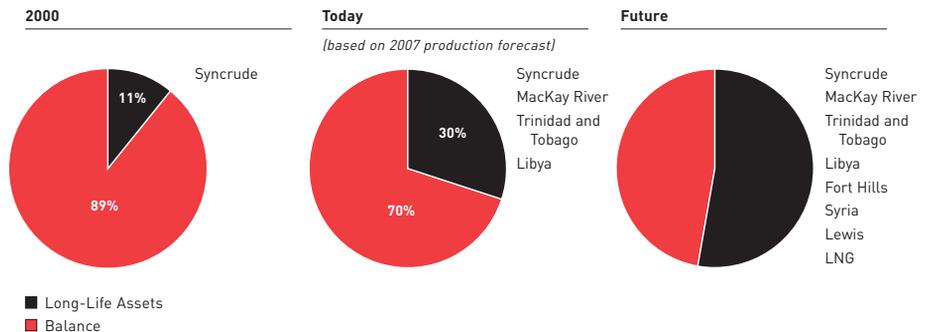
In the upstream, we define long-life assets as those projects that have more than 10 years of stable production. In the Downstream, refineries and gasoline stations share the same characteristic of having a long contributing life.

These kinds of assets provide sustainable cash flow and make us less dependent on exploration success for growth. It is also efficient to expand long-life assets from existing infrastructure.

Along with long-life assets, we pursue profitable growth through a balanced exploration program and business development.

## Long-Life Production (%)

In 2007, about 30% of Petro-Canada's production is expected to come from assets considered long-life. Successful execution of our business strategy will mean a higher proportion of long-life resources in the future.



## FUTURE GOALS:

2008

- complete Edmonton refinery conversion

2009

- complete Montreal coker project

2010

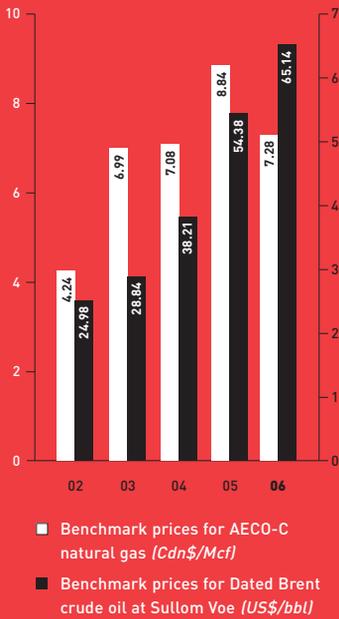
- first gas at Syrian Ash Shaer and Cherrife project
- complete MacKay River expansion

2011

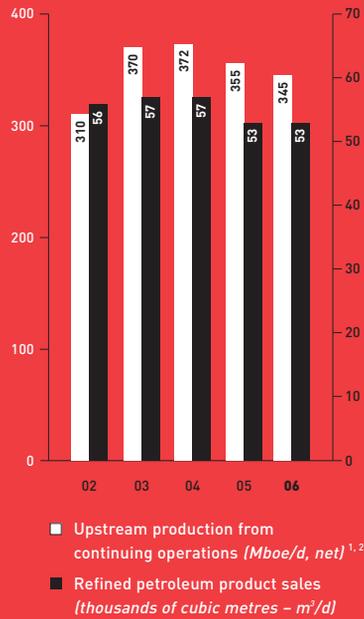
- start up Fort Hills

2006 RESULTS	2007 GOALS
<p><b>North American Natural Gas</b></p> <ul style="list-style-type: none"> <li>• completed regulatory hearing for the LNG facility at Gros-Cacouna</li> <li>• commenced a process to sell mature Brazeau and West Pembina facilities (sold in January 2007)</li> <li>• drilled 393 gross wells in Western Canada, including 291 wells in the Medicine Hat region</li> <li>• drilled more than 280 wells, added 50,000 net acres of land and continued CBM well de-watering in the U.S. Rockies</li> <li>• increased land position in Alaska to 1.5 million net acres of leased and option lands</li> </ul>	<ul style="list-style-type: none"> <li>• transition further into unconventional gas plays to about 25% of production</li> <li>• optimize opportunities around core assets</li> <li>• double U.S. Rockies production to 100 MMcfe/d by year end</li> <li>• increase focus on exploration</li> <li>• receive regulatory decision for the LNG facility</li> <li>• advance exploration prospects in the Mackenzie Delta/Corridor and Alaska</li> </ul>
<p><b>East Coast Oil</b></p> <ul style="list-style-type: none"> <li>• ramped up White Rose production to average 88,000 b/d (24,200 b/d net)</li> <li>• completed drilling the West White Rose 0-28 and North Amethyst K-15 delineation wells at White Rose</li> </ul>	<ul style="list-style-type: none"> <li>• advance in-field Hibernia growth prospects</li> <li>• delineate West White Rose</li> <li>• progress development plans for South White Rose Extension, North Amethyst and West White Rose prospects</li> </ul>
<p><b>Oil Sands</b></p> <ul style="list-style-type: none"> <li>• selected Sturgeon County for Fort Hills upgrader location and submitted commercial application</li> <li>• acquired oil sands leases adjacent to MacKay River and Fort Hills</li> <li>• completed Syncrude Stage III expansion and commenced production</li> <li>• completed third well pad at MacKay River and started production</li> </ul>	<ul style="list-style-type: none"> <li>• complete Fort Hills design basis and initial cost estimate, and start front-end engineering and design</li> <li>• receive regulatory decision on MacKay River expansion project</li> <li>• continue to ramp up Syncrude Stage III production</li> <li>• complete MacKay River water handling capacity upgrade and tie-in fourth well pad</li> </ul>
<p><b>International</b></p> <ul style="list-style-type: none"> <li>• achieved first production at De Ruyter and L5b-C</li> <li>• closed sale of mature Syrian producing assets and acquired 90% interest and became operator of Ash Shaer and Cherrife gas project</li> <li>• secured drilling rigs for 2007 and 2008 exploration programs</li> <li>• awarded Sirte licence in Libyan third round exploration and production-sharing agreements IV auction</li> </ul>	<ul style="list-style-type: none"> <li>• ramp up Buzzard and L5b-C to full production</li> <li>• achieve first production at Saxon in the U.K. sector of the North Sea</li> <li>• participate in up to a 17-well exploration drilling program (depending on rig arrival dates), with balanced risk profile</li> <li>• commence field appraisal and project design activities on the Ash Shaer and Cherrife development</li> <li>• establish a Libyan exploration program on the newly acquired Sirte exploration block</li> <li>• actively pursue LNG supply opportunities</li> </ul>
<p><b>Downstream</b></p> <ul style="list-style-type: none"> <li>• completed lubricant plant 25% expansion</li> <li>• completed detailed engineering and 18% of the Edmonton refinery conversion project</li> </ul>	<ul style="list-style-type: none"> <li>• continue the Edmonton refinery conversion project to enable the planned startup in 2008</li> <li>• complete Montreal coker feasibility study for investment decision in 2007</li> <li>• continue to invest in smaller scale refinery yield and reliability improvement projects</li> <li>• continue to integrate the Montreal refinery and the ParaChem Chemicals L.P. plant</li> </ul>

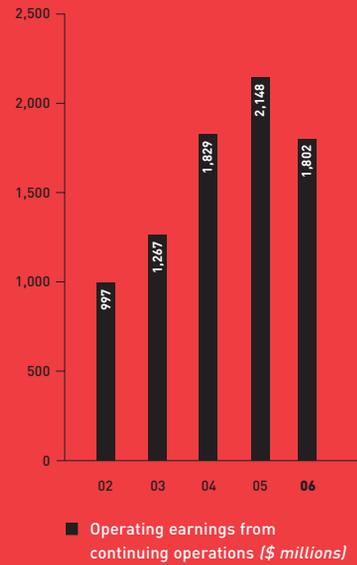
### Average Natural Gas/ Crude Oil Prices



### Upstream Production and Refined Petroleum Product Sales



### Operating Earnings From Continuing Operations<sup>1</sup>



1 Before royalties.  
2 Production from discontinued operations was 72 Mboe/d in 2002, 95 Mboe/d in 2003, 79 Mboe/d in 2004, 70 Mboe/d in 2005 and 6 Mboe/d in 2006.

1 Represents net earnings, excluding gains and losses on foreign currency and on disposal of assets, and unrealized gains or losses associated with the Buzzard derivative contracts.

Petro-Canada's integrated portfolio of businesses helped to deliver substantial financial results in 2006, despite the mixed business environment. Compared with 2005, lower natural gas prices were offset by higher oil prices and stronger refining margins.

Petro-Canada is in an enviable position of having a diverse suite of quality assets and projects to develop in the future. To get the full value from our existing businesses and future opportunities requires a company that is determined, focused and capable. We know execution is critical to success. That's why we continue to invest in growing employee capabilities.

90%

plus reliability at most of our operated facilities

# Capable

of delivering reliable operations and strong financials

In all areas, from refinery reliability to gasoline station market share, and from operating costs to facility uptime, we track our performance against our peers. We are not satisfied with our capability until we are among the best operators and providers of products and services. This means encouraging employees to set the bar high and constantly finding ways to improve operations, reduce costs and create innovative products and services.

Being capable also means having the financial ability to fund existing operations and growth, as well as return cash to shareholders. We're committed to financial discipline and flexibility. Our strong balance sheet is evidence of this commitment.



An operator at a Western Canada gas plant



Calgary's natural gas marketing floor



The Terra Nova FPSO



MacKay River *in situ* operations

# Driving for first quartile operation of our assets

plans to get Terra Nova into the

# 90%

reliability range

Our strategy is to improve the profitability of our base business by selecting the right assets and driving for first quartile performance. Execution, ensuring safe and reliable operations, will be the top priority in 2007.

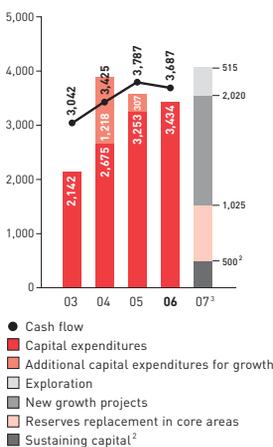
In the Downstream, our focus will be to maintain refinery reliability, increase non-petroleum revenue in retail and drive up higher margin product sales in lubricants. In the upstream, highly reliable facilities must stay that way. With an overheated energy sector, all our businesses face the challenge of trying to manage rising costs.

We also have to continually scrutinize our portfolio of assets for fit and purpose. Since 2000, Petro-Canada has disposed of nearly \$2 billion in non-core assets. This process continues, with the recent divestiture of our interests in two gas plants. In 2007, we expect to focus our portfolio even more, choosing only those projects and areas where we can make a material difference and we are sure we can execute effectively.

## Maintaining financial discipline and flexibility

**Cash Flow and Capital Expenditures from Continuing Operations<sup>1</sup>**

(\$ millions)



<sup>1</sup> Capital expenditures excluding acquisitions.

<sup>2</sup> Includes regulatory, asset enhancements and profitability improvement capital.

<sup>3</sup> As per the Company's forecast.

We base our capital program expenditures on expected cash flow over time to maintain maximum flexibility to react to market conditions and pursue new opportunities. In 2007, our capital expenditure program is expected to be \$4 billion. As we bring on big projects in the next few years, our capital program will likely increase to the \$4 billion to \$5 billion range. Our plan is to use cash flow from operations and access our strong balance sheet, as needed.

We have a strong balance sheet. Petro-Canada uses debt-to-cash flow from continuing operations as a key short-term leverage measure and debt-to-debt plus equity as a key long-term leverage measure.

We target no more than 2.0 times for our debt-to-cash flow from continuing operations and between 25% and 35% for our debt-to-debt plus equity. For the past few years, we've performed at rates significantly better than our targets. However, at times in the future, we might temporarily increase our ratios up to 2.5 times and 45% to fund the right opportunity.

Since 2000, we've returned \$3 billion to shareholders in the form of dividends and share buybacks. In 2006, we repurchased nearly 20 million shares, using surplus cash from operations and the proceeds from our sale of mature Syrian assets. We also announced a 30% increase to our quarterly dividend in December 2006, payable April 1, 2007, which represents the third consecutive year that we have announced a dividend increase.

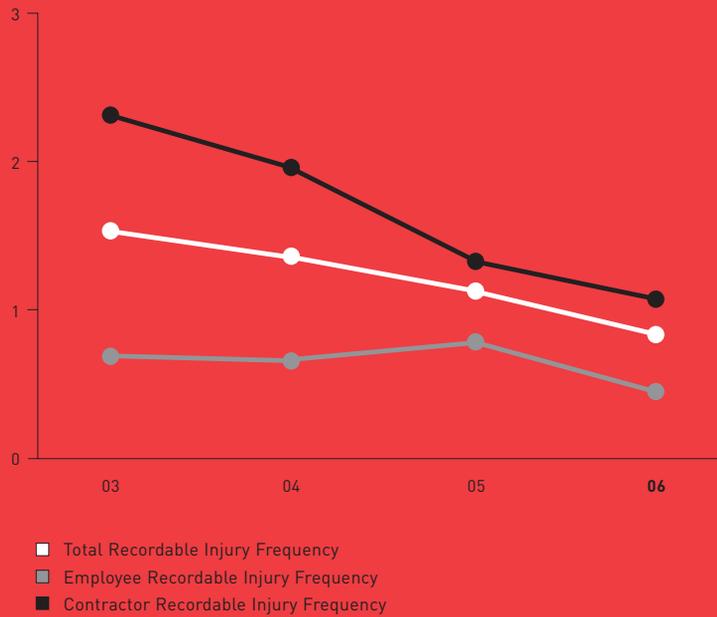
## DRIVING FOR FIRST QUARTILE OPERATIONS

2006 RESULTS		2007 GOALS
<b>North American Natural Gas</b>	<ul style="list-style-type: none"> <li>achieved better than 98% reliability at western Canadian facilities</li> <li>successfully conducted major turnaround at the Hanlan gas plant, with no air licence exceedances</li> </ul>	<ul style="list-style-type: none"> <li>sustain reliability performance</li> <li>continue to leverage costs through strategic alliances and preferred suppliers</li> </ul>
<b>East Coast Oil</b>	<ul style="list-style-type: none"> <li>completed Terra Nova turnaround for regulatory compliance and improved reliability</li> <li>saw operating and overhead costs increase, reflecting turnaround costs at Terra Nova</li> </ul>	<ul style="list-style-type: none"> <li>conduct 30-day turnaround scheduled at Hibernia for regulatory compliance</li> <li>receive regulatory approval to increase annual production from Sea Rose FPSO at White Rose</li> <li>complete 16-day turnaround at White Rose</li> <li>work toward improving Terra Nova reliability to the 90% range</li> </ul>
<b>Oil Sands</b>	<ul style="list-style-type: none"> <li>saw MacKay River operating costs increase by 5%, compared with 2005, reflecting Alberta business environment</li> <li>entered into Management Services agreement with Imperial Oil Resources at Syncrude for operational, technical and business services</li> <li>maintained reliability at MacKay River at 92%</li> <li>saw Syncrude non-fuel unit operating costs decrease 5%, compared with 2005</li> </ul>	<ul style="list-style-type: none"> <li>decrease MacKay River non-fuel unit operating costs by 10%, compared with 2006</li> <li>decrease Syncrude non-fuel unit operating costs by 10%, compared with 2006</li> <li>sustain MacKay River reliability at greater than 90%</li> </ul>
<b>International</b>	<ul style="list-style-type: none"> <li>achieved more than 95% uptime on Hanze platform</li> <li>achieved full production capacity at De Ruyter platform ahead of schedule</li> <li>seconded specialists to support Libyan operations</li> <li>improved Scott platform reliability and uptime by 33%, compared with 2005</li> </ul>	<ul style="list-style-type: none"> <li>maintain excellent reliability at De Ruyter platform</li> <li>optimize production capacity in Triton area by implementing recommendations from de-bottlenecking study</li> </ul>
<b>Downstream</b>	<ul style="list-style-type: none"> <li>achieved a combined reliability index of 95 at the Company's two refineries, above 90 for a second year in a row</li> <li>maintained leading share of retail major urban market</li> <li>grew convenience store sales by 8% and same store sales by 5%, compared with 2005</li> <li>achieved 75% high margin lubricant sales volume mix</li> <li>completed multi-year project to produce cleaner burning fuels at refineries</li> </ul>	<ul style="list-style-type: none"> <li>continue to focus on safety and refinery reliability</li> <li>increase retail non-petroleum revenue</li> <li>grow high margin lubricants sales volume</li> </ul>

## MAINTAINING FINANCIAL DISCIPLINE AND FLEXIBILITY

2006 RESULTS		2007 GOALS
<b>Being able to fund existing operations from cash</b>	<ul style="list-style-type: none"> <li>recorded cash flow from continuing operations of \$3.7 billion</li> <li>funded capital expenditure program from continuing operations of \$3.5 billion from cash flow and cash on hand</li> <li>maintained credit ratings on unsecured long-term debt securities of Baa2 from Moody's Investors Service, BBB from S&amp;P and A (low) from Dominion Bond Rating Service</li> </ul>	<ul style="list-style-type: none"> <li>fund \$4.1 billion capital expenditure program from expected cash flow, cash on hand and accessing balance sheet strength, as needed</li> <li>manage operating and capital costs within budgets</li> <li>maintain investment grade credit ratings</li> </ul>
<b>Having the financial flexibility to fund growth</b>	<ul style="list-style-type: none"> <li>ended the year with debt levels at 21.7% of total capital and a ratio of 0.8 times debt-to-cash flow</li> </ul>	<ul style="list-style-type: none"> <li>invest in additional growth opportunities when there is a strong business case</li> </ul>
<b>Providing cash to shareholders</b>	<ul style="list-style-type: none"> <li>renewed normal course issuer bid (NCIB) program in June 2006, entitling the Company to purchase up to 5% of the outstanding common shares, subject to certain conditions</li> <li>purchased 19,778,400 common shares at an average price of \$51.10/share for a total cost of \$1.011 billion</li> <li>declared a 30% increase in the quarterly dividend to \$0.13/share payable April 1, 2007</li> </ul>	<ul style="list-style-type: none"> <li>buy back shares when appropriate, although likely at lower levels than 2006</li> <li>regularly review the dividend strategy to align with financial and growth objectives, and shareholder expectations</li> </ul>

### Recordable Injuries by Year \*



\*Per 200,000 person hours

We have a Zero-Harm philosophy: the belief that work-related injuries and illnesses are foreseeable and preventable. Petro-Canada's total recordable injury frequency (TRIF) of 0.85 in 2006 was 25% lower than in 2005. Over the past six years, a commitment to improve our safety performance has moved us from an average rating to having among the best safety performances in our sector. We will continue to work hard toward our Zero-Harm goal.

We are committed to investing and conducting our operations in a way that is ethically, socially and environmentally responsible. We know we have to earn the support from those communities and people affected by our operations today and in the future.

more than

20%

reduction in environmental exceedances in 2006, compared with 2005

To help guide our actions and decision-making, we defined our own Principles for Responsible Investment and Operations back in 2002 based on the International Code of Ethics for Canadian Business. We also subscribe to the United Nations Global Compact and the Universal Declaration of Human Rights. Everyone at Petro-Canada has a role in our corporate responsibility efforts, from the employees who raised more than \$3 million for United Way campaigns in North America last year to the Environment, Health and Safety Committee of the Board of Directors that reviews environment, health and safety performance throughout the year.

*Our annual Report to the Community will be published in the second quarter of 2007.*



Habitat for Humanity



Testing treated water



Community park cleanup



Emergency response training

# Committed

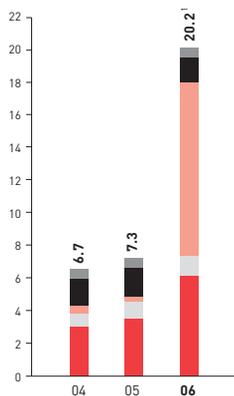
to doing the right thing in communities, the environment and society

# Following our principles for responsible investment and operations

## Cash and In-Kind Contributions of More Than \$20 Million in 2006

(% – Contribution in North America  
unless otherwise stated, unaudited)  
Years ended December 31

(millions of Canadian dollars)



- Local community support<sup>1</sup>
- United Way
- Olympic/Paralympic Games
- Education
- Environment

<sup>1</sup> The total includes community partnership funding, as well as other community support in the form of equipment, property and cash donations from various operating budgets.

Our Principles guide our actions and track our performance in the areas of business conduct, community support, environment, and working conditions and human rights. As part of this, we continue to strengthen our ethical culture and train employees on our Code of Business Conduct Policy.

There is a growing concern about the impact the energy sector has on the environment. We continue to look for ways to reduce the effect we have on land, water and air. Our areas of focus are our use of water, greenhouse gas emissions (GHGs) and biodiversity.

We have more than 5,000 employees and many contractors working on our behalf. They deserve respectful and meaningful employment. In 2006, we recruited more than 650 new employees. We are committed to providing them with a safe place to work where they can learn and make a difference.

### COMMUNITY PARTNERSHIPS AND PETRO-CANADA'S EMERGING LEADERS PROGRAM

In 2006, we completed a review of our community partnership program that led us to three focus areas: education, environment and local community support. To help address Canada's growing skills shortage, we launched our new Petro-Canada Emerging Leaders program with a \$1 million contribution to McGill University, a \$2 million contribution to the Northern Alberta Institute of Technology and, in early 2007, a \$1 million contribution to the University of Alberta.

### PARTNERING WITH THE OLYMPIC AND PARALYMPIC TEAMS

As Vancouver's 2010 exclusive national oil and gas partner, Petro-Canada proudly supports the Canadian Olympic and Paralympic Teams in Beijing 2008, Vancouver 2010 and London 2012. We are a grassroots supporter, fuelling the dreams of athletes and coaches. We work with several Canadian Olympic organizations, including the Canadian Olympic Committee, the Canadian Paralympic Committee, Vancouver 2010 and the Coaching Association of Canada.



PRINCIPLES	2006 RESULTS	2007 GOALS
<b>Business conduct</b> <ul style="list-style-type: none"> <li>• comply with applicable laws and regulations</li> <li>• apply our Code of Business Conduct wherever we operate</li> <li>• seek contractors, suppliers and agents whose practices are consistent with our principles</li> </ul>	<ul style="list-style-type: none"> <li>• provided training to 120 employees and contractors on U.S. anticorruption laws and more than 1,200 employees on compliance with antitrust laws</li> <li>• formalized processes to communicate, train and steward performance to Code of Business Conduct</li> <li>• strengthened auditing aspects of the Total Loss Management system</li> </ul>	<ul style="list-style-type: none"> <li>• improve training for Code of Business Conduct and Privacy Policies</li> <li>• strengthen leaders understanding of their role in sustaining a culture of integrity</li> <li>• improve pre-selection and communication of Code of Conduct expectations with contractors</li> </ul>
<b>Community</b> <ul style="list-style-type: none"> <li>• strive within our sphere of influence to ensure a fair share of benefits to stakeholders impacted by our activities</li> <li>• conduct meaningful and transparent consultation with all stakeholders</li> <li>• endeavour to integrate our activities with, and participate in, local communities as good corporate citizens</li> </ul>	<ul style="list-style-type: none"> <li>• received feedback from more than 100 external stakeholders, who identified areas to build on our recognized capability in stakeholder engagement</li> <li>• strengthened Aboriginal recruitment strategy and practices</li> <li>• restructured the community partnerships program, targeted at education, environment and local community support</li> </ul>	<ul style="list-style-type: none"> <li>• develop Stakeholder Engagement Policy and improve training and capability development</li> <li>• increase Aboriginal community participation in business opportunities to provide goods and services</li> <li>• better measure the socio-economic impact on the communities in which we operate</li> <li>• assess the effectiveness of key community partnership initiatives</li> </ul>
<b>Environment</b> <ul style="list-style-type: none"> <li>• conduct our activities with sound environmental management and conservation practices</li> <li>• strive to minimize the environmental impact of our operations</li> <li>• work diligently to prevent any risk to community health and safety from our operations or our products</li> <li>• seek opportunities to transfer expertise in environmental protection to host communities</li> </ul>	<ul style="list-style-type: none"> <li>• began developing an environmental information management system, with initial focus on GHGs and primary air pollutants</li> <li>• initiated water strategy project, with more work required in 2007</li> <li>• reduced environmental exceedances by more than 20%, while spills remained relatively flat in 2006, compared with 2005</li> <li>• submitted environmental and social impact assessments for the Fort Hills upgrader, the MacKay River expansion, the Saxon project in the North Sea and seismic and drilling in Syria</li> </ul>	<ul style="list-style-type: none"> <li>• strengthen environmental stewardship by developing specific commitments and indicators for air, land and water management</li> <li>• complete first phase of the environmental management system to steward performance against principles and indicators</li> <li>• improve method to capture and report environmental expenditures</li> <li>• submit environmental impact assessment in support of drilling programs in Trinidad and Tobago</li> </ul>
<b>Working conditions and human rights</b> <ul style="list-style-type: none"> <li>• provide a healthy, safe and secure work environment</li> <li>• honour internationally accepted labour standards prohibiting child labour, forced labour and discrimination in employment</li> <li>• respect freedom of association and expression in the workplace</li> <li>• not be complicit in human rights abuses</li> <li>• support and respect the protection of human rights within our sphere of influence</li> </ul>	<ul style="list-style-type: none"> <li>• achieved TRIF of .85, breaking the 1.0 barrier and becoming among the best safety performers in our industry</li> <li>• held safety learning forums with senior leaders, front-line management and contractors</li> <li>• influenced safety standard improvements among contractors participating in Terra Nova turnaround</li> <li>• piloted project to develop standardized criteria for pre-qualifying contractors based on safety</li> <li>• drafted and tested a pandemic response plan</li> <li>• announced annual President's Award to recognize safety</li> </ul>	<ul style="list-style-type: none"> <li>• sustain and further improve safety</li> <li>• develop health performance metrics to address and mitigate the impact of employee illness</li> <li>• enhance the social risk impact assessment process in the project management model</li> </ul>

**EXECUTIVE  
LEADERSHIP TEAM\***

**Ron A. Brenneman**  
President and  
Chief Executive Officer

**Neil J. Camarta**  
Senior Vice-President,  
Oil Sands

**William A. Fleming\*\***  
Vice-President,  
East Coast Oil

**Boris J. Jackman**  
Executive Vice-President,  
Downstream

**Peter S. Kallos**  
Executive Vice-President,  
International

**E.F.H. Roberts**  
Executive Vice-President and  
Chief Financial Officer

**Kathleen E. Sendall**  
Senior Vice-President,  
North American Natural Gas

**ASSOCIATE MEMBERS**

**Scott R. Miller**  
Vice-President,  
General Counsel

**M. A. (Greta) Raymond**  
Vice-President,  
Environment, Safety and  
Social Responsibility

**Andrew Stephens**  
Vice-President,  
Human Resources

**BOARD OF DIRECTORS\***

**Ron A. Brenneman**  
President and  
Chief Executive Officer  
Petro-Canada

**Angus A. Bruneau, o.c.\*\*\***  
Corporate Director

**Gail Cook-Bennett**  
Chairperson  
Canada Pension Plan  
Investment Board

**Richard J. Currie, o.c.**  
Chairman of the Board  
BCE Inc.

**Claude Fontaine, o.c.**  
Counsel  
Ogilvy Renault

**Paul Haseldonckx**  
Corporate Director

**Thomas E. Kierans, o.c.**  
Chairman  
Canadian Journalism  
Foundation

**Brian F. MacNeill, c.m.**  
Chairman of the Board  
Petro-Canada

**Maureen McCaw**  
Corporate Director

**Paul D. Melnuk**  
Chairman and  
Chief Executive Officer  
Thermadyne Holdings  
Corporation and  
Managing Partner  
FTL Capital Partners

**Guylaine Saucier, F.C.A., C.M.**  
Corporate Director

**James W. Simpson**  
Corporate Director

**SECRETARY TO THE  
BOARD OF DIRECTORS**

**Hugh L. Hooker**  
Chief Compliance Officer,  
Associate General Counsel  
and Corporate Secretary

\*As of December 31, 2006.

\*\*Mr. Fleming retired in February 2007.

\*\*\*Dr. Bruneau will retire at the end of the Annual Meeting on April 24, 2007.

We strive to maintain high standards of corporate governance, with a focus on a strong and diligent Board of Directors and transparency for shareholders. The Corporate Governance and Nominating Committee is responsible for development of, and compliance with, corporate governance policies and procedures. More detailed information on corporate governance can be found on pages 87 to 90 of Petro-Canada's 2006 Financial Report, the Management Proxy Circular or in the investor centre section of our website at [www.petro-canada.ca](http://www.petro-canada.ca).

Along with this 2006 Strategic Overview Report, Petro-Canada publishes a 2006 Financial Report, which includes our Management's Discussion and Analysis, Consolidated Financial Statements and Notes, Operating and Financial Highlights, Reserves Information, and Corporate Governance Overview. An online version is available at [www.petro-canada.ca](http://www.petro-canada.ca). Our annual Report to the Community will be published in the second quarter of 2007 and will also be available on our website.

**INVESTOR INQUIRIES**

Telephone: 403-296-4040  
Fax: 403-296-3061  
E-mail: [investor@petro-canada.ca](mailto:investor@petro-canada.ca)

**MEDIA INQUIRIES**

Corporate Communications  
Telephone: 403-296-3648

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Petro-Canada  
P.O. Box 2844  
Calgary, Alberta, Canada T2P 3E3  
Telephone: 403-296-8000  
Fax: 403-296-3030  
Website: [www.petro-canada.ca](http://www.petro-canada.ca)

## LEGAL NOTICE – FORWARD-LOOKING INFORMATION

This Strategic Overview Report contains forward-looking information. You can usually identify this information by such words as “*plan*,” “*anticipate*,” “*forecast*,” “*believe*,” “*target*,” “*intend*,” “*expect*,” “*estimate*,” “*budget*” or other similar wording suggesting future outcomes or statements about an outlook. We list below examples of references to forward-looking information:

- business strategies and goals
- outlook (including operational updates and strategic milestones)
- future capital, exploration and other expenditures
- future resource purchases and sales
- construction and repair activities
- refinery turnarounds
- anticipated refining margins
- future oil and gas production levels and the sources of their growth
- project development and expansion schedules and results
- future results of exploration activities and dates by which certain areas may be developed or may come on-stream
- retail throughputs
- pre-production and operating costs
- reserves and resources estimates
- royalties and taxes payable
- production life-of-field estimates
- natural gas export capacity
- future financing and capital activities (including purchases of Petro-Canada common shares under the Company’s NCIB program)
- contingent liabilities (including potential exposure to losses related to retail licensee agreements)
- environmental matters
- future regulatory approvals

Such forward-looking information is subject to known and unknown risks and uncertainties. Other factors may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such information. Such factors include, but are not limited to:

- industry capacity
- imprecise reserves estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as reserves
- the effects of weather and climate conditions
- the results of exploration and development drilling and related activities
- the ability of suppliers to meet commitments
- decisions or approvals from administrative tribunals
- risks attendant with domestic and international oil and gas operations
- expected rates of return
- general economic, market and business conditions
- competitive action by other companies
- fluctuations in oil and gas prices
- refining and marketing margins
- the ability to produce and transport crude oil and natural gas to markets
- fluctuations in interest rates and foreign currency exchange rates
- actions by governmental authorities, including changes in taxes, royalty rates and resource-use strategies
- changes in environmental and other regulations
- international political events

Many of these and other similar factors are beyond the control of Petro-Canada. Petro-Canada discusses these factors in greater detail in filings with the Canadian provincial securities commissions and the U.S. Securities and Exchange Commission (SEC).

We caution readers that this list of important factors affecting forward-looking information is not exhaustive. Furthermore, the forward-looking information in this Strategic Overview Report is made as of March 1, 2007 and, except as required by applicable law, Petro-Canada does not update it publicly or revise it. This cautionary statement expressly qualifies the forward-looking information in this Strategic Overview Report.

### Petro-Canada disclosure of reserves

Petro-Canada’s qualified reserves evaluators prepare the reserves estimates the Company uses. The Canadian provincial securities commissions do not consider our reserves staff and management as independent of the Company. Petro-Canada has obtained an exemption from certain Canadian reserves disclosure requirements that allows us to make disclosure in accordance with SEC standards. This exemption allows comparisons with U.S. and other international issuers.

As a result, Petro-Canada formally discloses its reserves data and other oil and gas data using U.S. requirements and practices, and these may differ from Canadian domestic standards and practices. Note that when we use the term boe in this Strategic Overview Report, it may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl is based on an energy equivalency conversion method. This method primarily applies at the burner tip and does not represent a value equivalency at the wellhead.

To disclose reserves in SEC filings, oil and gas companies must prove they are economically and legally producible under existing economic and operating conditions. Proof comes from actual production or conclusive formation tests. The use of terms such as “*probable*,” “*possible*,” “*recoverable*,” or “*potential reserves and resources*” in this Strategic Overview Report does not meet the SEC guidelines for SEC filings.

The table below describes the industry definitions that we currently use:

Definitions Petro-Canada uses	Reference
Proved oil and gas reserves (includes both proved developed and proved undeveloped)	U.S. SEC reserves definition (Accounting Rules Regulation S-X 210.4-10, FASB-69)
Unproved reserves, probable and possible reserves	CIM (Petroleum Society) definitions (Canadian Oil and Gas Evaluation Handbook, Vol. 1 Section 5)
Contingent and prospective resources	Society of Petroleum Engineers, World Petroleum Congress and American Association of Petroleum Geologist definitions (approved February 2000)

There is no certainty that it will be economically viable or technically feasible to produce any portion of the resources. For use in this Strategic Overview Report, “*total resources*” means reserves plus resources.

SEC regulations do not define proved reserves from our oil sands mining operations as an oil and gas activity. These reserves are classified as a mining activity and are estimated in accordance with SEC Industry Guide 7. For internal management purposes, we view these reserves and their development as part of our total exploration and production operations.

Throughout this Strategic Overview Report, total Company reserves, total Company production, total Company reserves replacement and total Company RLI are calculated using the sum of oil and gas activities, and oil sands mining activities. Before royalties, oil sands mining 2006 year-end proved reserves were 345 million barrels (MMbbls) and oil sands mining annual 2006 production was 11 MMbbls.

### NON-GAAP MEASURES

Cash flow, which is expressed as cash flow from operating activities before changes in non-cash working capital, is used by the Company to analyse operating performance, leverage and liquidity. Operating earnings represent net earnings, excluding gains or losses on foreign currency translation, disposal of assets and unrealized gains or losses on the mark-to-market valuation of the derivative contracts associated with the Buzzard acquisition. Operating earnings are used by the Company to evaluate operating performance. Cash flow and operating earnings do not have a standardized meaning prescribed by Canadian GAAP and, therefore, may not be comparable with the calculation of similar measures for other companies. For reconciliation of the operating earnings and cash flow amounts to the associated GAAP measures, refer to the tables on pages 12 and 14, respectively, of the Financial Report available on our website at [www.petro-canada.ca](http://www.petro-canada.ca).

*Publié également en français*



# Capable



PETRO-CANADA'S 2006 FINANCIAL REPORT



“Clear, capable and committed” are the words we use to describe Petro-Canada. The Company has a clear business focus and strategy for the future, with well-defined next steps for delivery. Petro-Canada is a capable company – able to execute plans and deliver value. We are committed to “doing the right thing,” which means making sure our actions reflect a principled company.

## Clear. Capable. Committed.



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Throughout this Financial Report, total Company reserves, total Company production, total Company reserves replacement and total Company reserves life index (RLI) are calculated using the sum of oil and gas activities, and oil sands mining activities. Before royalties, oil sands mining 2006 year-end proved reserves were 345 million barrels (MMbbls) and oil sands mining annual 2006 production was 11 MMbbls.

The Strategic Overview Report, published under separate cover, but available at the same time as the Financial Report, provides additional detail on the Company's business strategy and progress toward delivering on long-term goals. This Financial Report provides more detail on Petro-Canada's operational and financial capability. The Report to the Community, which the Company publishes in mid-2007, will elaborate on Petro-Canada's commitment to corporate responsibility objectives and performance.

Petro-Canada is one of Canada's largest oil and gas companies, operating in both the upstream and the downstream sectors of the industry in Canada and internationally. The Company creates value by responsibly developing energy resources and providing world class petroleum products and services. Petro-Canada is proud to be a National Partner to the Vancouver 2010 Olympic and Paralympic Winter Games. Petro-Canada's common shares trade on the Toronto Stock Exchange (TSX) under the symbol PCA and on the New York Stock Exchange (NYSE) under the symbol PCZ.

## Management's Discussion and Analysis

*This Management's Discussion and Analysis (MD&A), dated effective as of February 12, 2007, should be read in conjunction with the audited Consolidated Financial Statements and Notes for the year ended December 31, 2006, included in the 2006 Financial Report and the 2006 Annual Information Form (AIF). Financial data has been prepared in accordance with Canadian generally accepted accounting principles (GAAP), unless otherwise specified. All dollar values are Canadian dollars, unless otherwise indicated. All oil and natural gas production and reserves volumes are stated before deduction of royalties, unless otherwise indicated. Graphs accompanying the text identify the Company's "value drivers," the key measures of performance in each segment of Petro-Canada's business. A glossary of financial terms and ratios can be found on page 92 of this report.*

### NON-GAAP MEASURES

Cash flow, which is expressed as cash flow from operating activities before changes in non-cash working capital, is used by the Company to analyse operating performance, leverage and liquidity. Operating earnings represent net earnings, excluding gains or losses on foreign currency translation, disposal of assets and unrealized gains or losses on the mark-to-market valuation of the derivative contracts associated with the Buzzard acquisition. Operating earnings are used by the Company to evaluate operating performance. Cash flow and operating earnings do not have a standardized meaning prescribed by Canadian GAAP and, therefore, may not be comparable with the calculation of similar measures for other companies. For reconciliation of the operating earnings and cash flow amounts to the associated GAAP measures, refer to the tables on pages 12 and 14, respectively, of this MD&A.

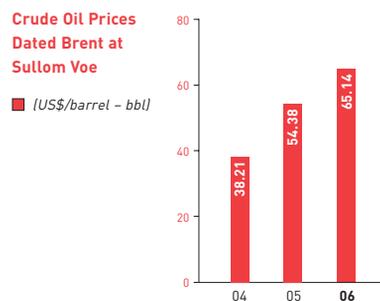
## Business Environment

The major economic factors influencing Petro-Canada's upstream financial performance include crude oil and natural gas prices, and foreign exchange, particularly the Canadian dollar/U.S. dollar rates. Crude oil and natural gas prices are affected by a number of factors, including supply and demand balance, weather and political events. Factors influencing Downstream financial performance include the level and volatility of crude oil prices, industry refining margins, movements in crude oil price differentials, demand for refined petroleum products and the degree of market competition.

### BUSINESS ENVIRONMENT IN 2006

The year 2006 was characterized by volatile crude oil and natural gas prices. The price of North Sea Brent (Dated Brent) moved between highs in excess of \$77 US/bbl, to lows of almost \$55 US/bbl. Similarly, benchmark North American natural gas prices at the Henry Hub fluctuated between highs in excess of \$10 US/million British thermal units (MMBtu) to lows close to \$4 US/MMBtu.

On an annual average basis, the price of Dated Brent reached \$65.14 US/bbl, its highest annual average value ever and almost 20% higher than the average in 2005. High oil prices in 2006 were driven by continuing demand growth from China and increased geopolitical tensions globally.

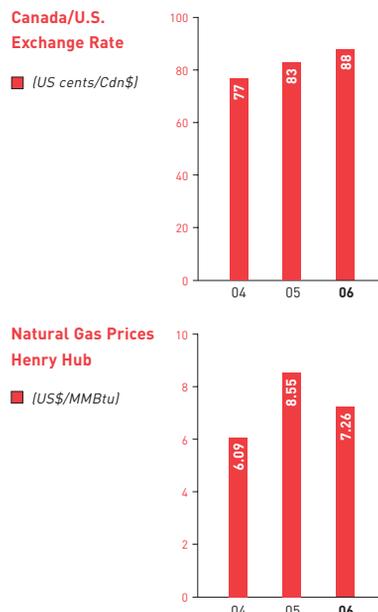


Relative to last year, international light/heavy crude (Dated Brent/Mexican Maya) price differentials stabilized in 2006 around the \$14 US/bbl level, while Canadian light/heavy crude (Edmonton Light/Western Canada Select (WCS)) spreads narrowed noticeably.

The continuing appreciation of the Canadian dollar during 2006 reduced the positive impact of higher international prices on Canadian crude prices. The Canadian dollar averaged 88 cents US in 2006, compared with 83 cents US in 2005.

North American natural gas prices suffered a setback during 2006. Record high levels of gas in storage and lower weather-related demand led to significantly lower prices, compared with 2005. Henry Hub prices averaged \$7.26 US/MMBtu in 2006, 15% lower than in 2005. Natural gas prices in 2005 reflected the severe impact of hurricanes on U.S. Gulf of Mexico production. In 2006, the Canadian natural gas price at the AECO-C hub fell in line with U.S. prices and averaged almost 18% below its 2005 level.

In the downstream sector, it is estimated that, in 2006, refined petroleum product sales in Canada declined by 1% on top of the 1% reduction in 2005. In spite of lower overall industry product sales and relatively unchanged international light/heavy crude price spreads, overall refining margins increased in 2006, compared with 2005. The impact of the introduction of ultra-low sulphur diesel in the U.S. and Canada effective June 2006 was to maintain heating crack spreads at strong levels. The phasing out of Methyl Tertiary Butyl Ether (MTBE) from gasoline in the U.S. and a heavy refinery turnaround season helped to improve gasoline margins relative to 2005.



### Commodity Price Indicators and Exchange Rates

(averages for the years indicated)

		2006	2005	2004
Crude oil price indicators (per bbl)				
Dated Brent at Sullom Voe	US\$	65.14	54.38	38.21
West Texas Intermediate (WTI) at Cushing	US\$	66.22	56.56	41.40
WTI/Dated Brent price differential	US\$	1.08	2.18	3.19
Dated Brent/Mexican Maya price differential	US\$	13.94	13.52	8.20
Edmonton Light	Cdn\$	73.23	69.22	52.78
Edmonton Light/WCS (heavy) price differential	Cdn\$	22.40	25.27	N/A
Natural gas price indicators				
Henry Hub (per MMBtu)	US\$	7.26	8.55	6.09
AECO-C spot (per Mcf)	Cdn\$	7.28	8.84	7.08
Henry Hub/AECO basis differential (per MMBtu)	US\$	1.09	1.53	0.87
New York Harbor 3-2-1 refinery crack spread (per bbl)	US\$	9.80	9.47	7.02
US\$ per Cdn\$ exchange rate	US\$	0.88	0.83	0.77

### COMPETITIVE CONDITIONS

It is becoming increasingly challenging for the energy sector to find new sources of oil and gas. Petro-Canada is well positioned to compete successfully for new opportunities that could complement existing upstream resources and increase production of oil and gas. The Company has an estimated 15.9 billion boe of total resources from which to develop new production. Approximately two-thirds of the total resources are located in Alberta's oil sands. As well, with different upstream businesses operating in Canada and internationally, the Company has the flexibility to pursue a wide range of opportunities. While the Company has wide operational scope, it remains a mid-sized global company as measured by production levels. This means Petro-Canada has the operational capability and balance sheet strength to invest in large projects, but smaller acquisitions can also impact the Company's production levels and financial returns.

Petro-Canada is well positioned to compete in the petroleum product refining and marketing business in Canada. The Company accounts for 13% of the total refining capacity in Canada and has a 16% share of the petroleum products market in Canada. Its 1,312 retail service station network has the highest gasoline sales per site in Canada among the national integrated oil companies. It also has Canada's largest commercial road transport network, with 219 locations, as well as a robust bulk fuel sales channel.

The Company believes that its strong financial position, combined with a track record of executing large capital projects and depth of management experience will enable it to continue to compete successfully in the current business environment.

## OUTLOOK FOR BUSINESS ENVIRONMENT IN 2007

Prices for energy commodities are expected to remain volatile in 2007, reflecting the unpredictable nature of weather, the level of industry inventories, and political and natural events. High levels of crude oil and refined product inventories, coupled with increased supplies from countries outside of the Organization of the Petroleum Exporting Countries (OPEC), are expected to be more than enough to meet anticipated growth in global oil demand during 2007, thus lessening the upward pressure experienced by oil prices during 2006. The extent of the anticipated price correction will depend on OPEC production adjustments as it tries to mitigate downward price pressures arising from slackened global supply/demand conditions.

Demand growth in North American natural gas markets is expected to be minimal due primarily to lower weather-related demand experienced for most of this heating season. This, combined with high levels of gas in storage, will continue to exert downward pressure on natural gas prices across the continent. The resultant downward pressure on natural gas prices could be partially offset by the challenge to grow production.

In the industry's downstream sector, 2007 refining margins are expected to remain highly volatile and are unlikely to match the high levels experienced in 2006 due to the expectation of slower growth in U.S. and Canadian refined product sales and narrower light/heavy price differentials. The uncertainty arising from continuing changes in the specification for key products, such as motor gasoline and middle distillates, will be a contributing factor to the expected volatility in margins. Also, potential shifts in weather patterns, such as warmer-than-normal temperatures driving down demand for heating fuels or a severe hurricane season that results in damage to key refining centres could influence refining margins in 2007.

## ECONOMIC SENSITIVITIES

The following table shows the estimated after-tax effects that changes in certain factors would have had on Petro-Canada's 2006 net earnings from continuing operations had these changes occurred.

Sensitivities affecting net earnings Factor <sup>1,2</sup>	Change (+)	Annual Net Earnings Impact	Annual Net Earnings Impact
		(millions of Canadian dollars)	(\$/share) <sup>3</sup>
<b>Upstream</b>			
Price received for crude oil and liquids <sup>4</sup>	\$ 1.00/bbl	\$ 39	\$ 0.08
Price received for natural gas	\$ 0.25/Mcf	32	0.06
Exchange rate: Cdn\$/US\$ refers to impact on upstream operating earnings from continuing operations <sup>5</sup>	\$ 0.01	(33)	(0.07)
Crude oil and liquids production (barrels per day – b/d)	1,000 b/d	9	0.02
Natural gas production (million cubic feet per day – MMcf/d)	10 MMcf/d	9	0.02
<b>Downstream</b>			
New York Harbor 3-2-1 crack spread	\$ 0.10 US/bbl	5	0.01
Light/heavy crude price differential	\$ 1.00 US/bbl	6	0.01
<b>Corporate</b>			
Exchange rate: Cdn\$/US\$ refers to impact of the revaluation of U.S. dollar-denominated, long-term debt <sup>6</sup>	\$ 0.01	\$ 14	\$ 0.03

1 The impact of a change in one factor may be compounded or offset by changes in other factors. This table does not consider the impact of any inter-relationship among the factors.

2 The impact of these factors is illustrative.

3 Per share amounts are based on the number of shares outstanding at December 31, 2006.

4 This sensitivity is based upon an equivalent change in the price of WTI and Dated Brent.

5 A strengthening Canadian dollar versus the U.S. dollar has a negative effect on upstream earnings from continuing operations.

6 A strengthening Canadian dollar versus the U.S. dollar has a positive effect on corporate earnings because the Company holds U.S. denominated debt. The impact refers to gains or losses on \$1.4 billion US of the Company's U.S. denominated long-term debt and interest costs on U.S. denominated debt. Gains or losses on \$1.1 billion US of the Company's U.S. denominated long-term debt, associated with the self-sustaining International business segment and the U.S. Rockies operations included in the North American Natural Gas business segment, are deferred and included as part of shareholders' equity.

# Business Strategy

## VALUE PROPOSITION AND STRATEGY

The value proposition Petro-Canada offers to its investors can best be summarized as “Integrated Value from a Diversified Resource Base.” The Company’s business strategy continues to be:

- improving the profitability of the base business
  - selecting the right assets to develop and then driving for first quartile performance<sup>1</sup>
- taking a disciplined approach to profitable growth
  - leveraging existing assets
  - accessing new opportunities with a focus on long-life assets
  - building a balanced exploration program

Execution of the corporate strategy across all the business units is based on our key beliefs. These influence decisions Petro-Canada makes to deliver value from the integrated portfolio. The Company believes its structure and scope strategically position Petro-Canada to deliver long-term shareholder value. For example, with a base in Canada, Petro-Canada is situated in a stable, resource-rich and demand-driven market. An international presence and integration across businesses provide the Company access to more growth opportunities and an ability to better manage risk. As a mid-sized global company, even smaller sized investments can have a material impact. Last, the Company is committed to developing energy resources responsibly and encouraging opportunities and growth for employees.

## EXECUTION OF THE STRATEGY IN 2006

### IMPROVING BASE BUSINESS PROFITABILITY

The cornerstone of improving the profitability of the base business is delivering operational excellence. Petro-Canada expects its operated and non-operated facilities to run with high reliability and prudently managed costs. These measures are constantly tracked, reported and improved upon.

- In East Coast Oil, the partner-operated platforms at Hibernia and White Rose had solid operational performance in 2006. Petro-Canada operated Terra Nova had a challenging year when a planned maintenance turnaround was advanced and the turnaround to complete regulatory inspections and reliability improvements was extended. In November, oil production from the Terra Nova field resumed and the Company is targeting to achieve reliability<sup>2</sup> above 90% over time.
- In North American Natural Gas, Western Canada natural gas processing facilities operated at reliability rates greater than 98%. In 2006, the business continued to be faced with industry-wide cost pressures.
- In Oil Sands, the MacKay River *in situ* plant operated at more than 92% reliability. The independently operated Syncrude facility had varying reliability performance through the year, experiencing some delays bringing on the Stage III expansion mid-year, but providing increased production for the last four months of the year.
- The International business unit’s production from Northwest Europe exceeded expectations, led by high reliability and the early ramp up to full production of the De Ruyter field. This strong performance was partially offset by lower reservoir performance in Libya and Train 4 startup problems in Trinidad and Tobago.
- In the Downstream, solid operations at the Edmonton and Montreal refineries resulted in a combined reliability index of 95. The Company completed its ultra-low sulphur diesel projects at its Edmonton and Montreal refineries, thereby providing cleaner burning fuels to consumers. A fire at the lubricants plant early in the year was a setback; however, the facility operated with solid reliability for the remainder of the year.
- Corporate wide, the Company views safety and environmental performance as an indicator of operational excellence. In 2006, total recordable injury frequency (TRIF) was reduced by 25% and environmental exceedances were lowered by more than 20%, compared with 2005.

<sup>1</sup> References to first quartile operations in this report do not refer to industry-wide benchmarks or externally known measures. The Company has a variety of internal metrics that define and track first quartile operational performance.

<sup>2</sup> Throughout this MD&A, the Company refers to reliability within the five business units. These reliability rates are calculated using internal methods that vary among the business units and take various factors into account. There are no existing external or industry-wide standards used in calculating reliability rates and, therefore, resulting calculations are not necessarily comparable to other companies in the oil and gas industry.

## LONG-TERM PROFITABLE GROWTH

The Company recognizes that adding new material opportunities is fundamental to long-term growth. Petro-Canada is seeking to increase the relative proportion of long-life resources in the portfolio as a means to deliver sustainable cash flow and earnings. In addition to bringing major projects on-stream, the Company is creating value through its balanced exploration program and business development opportunities.

- In East Coast Oil, discoveries were made in the west and southwest sections of the White Rose field in 2006. Petro-Canada and its partners suspended negotiations with the Government of Newfoundland and Labrador on the Hebron development; however, Petro-Canada continues to consider Hebron a quality asset. At Hibernia, government approval of the development plans for the Southern Extension were not received in 2006, limiting additional production in 2007.
- In North American Natural Gas, the business continued to focus on optimizing the Company's conventional assets and on the transition to unconventional production in Western Canada and the U.S. Rockies. Water treatment permits for wells in the U.S. Rockies were approved, permitting the ramp up of coal de-watering. While the Company is optimistic about its coal bed methane (CBM) opportunities in the U.S. Rockies, it also plans to bring on additional tight gas in areas like the Denver-Julesburg Basin. Progress was also made on the longer term strategy of accessing new supplies, with the addition of acreage in Alaska and advancement of the proposed Gros-Cacouna re-gasification project.
- In Oil Sands, Petro-Canada advanced the Fort Hills project with the filing of a regulatory application to construct and operate the Sturgeon Upgrader near Edmonton. MacKay River production capacity was increased with the addition of a third well pad. The Company also increased *in situ* oil sands landholdings with the purchase of additional leases adjacent to MacKay River.
- In International, Petro-Canada completed the sale of the Company's mature, high-decline producing assets in Syria. Later in the year, the Company completed an agreement to purchase a 90% interest in the Ash Shaer and Cherrife natural gas fields in central Syria, with future plans to build and operate a long-life natural gas development. In the Netherlands sector of the North Sea, the Company-operated De Ruyter project achieved first oil in September, while L5b-C achieved first natural gas in November. In September 2006, the Company furthered its balanced exploration program by securing drilling rigs for its 2007 and 2008 well programs. As well, exploration acreage was added in Libya and the North Sea in 2006. In the United Kingdom (U.K.) sector of the North Sea, the Buzzard project achieved first oil in early 2007. The field is expected to ramp up to full production in mid-2007.
- In the Downstream, capacity at the lubricants plant was expanded by 25% in 2006. Construction to convert the Edmonton refinery to process 100% bitumen-based feedstock commenced and, by year end, 18% of the project was complete. The Downstream also furthered work to evaluate the feasibility of adding a coker to the Montreal refinery.

## BUSINESS STRATEGY LOOKING FORWARD

Ensuring existing facilities run safely, reliably and efficiently through excellent execution will continue to be a key focus for Petro-Canada. This same focus on execution will apply to the advancement of major projects. Business plans see the Company adding five major projects over the next several years. Most of these are long-life projects with stable production for 10 years or more. The Buzzard project will ramp up in 2007 and the Edmonton refinery conversion project has been sanctioned and is under construction, with expected completion in 2008. The subsequent projects, shown in the table, are expected to be sanctioned once sufficient front-end engineering work has been completed. Capital expenditures are expected to increase to between \$4 billion and \$5 billion per year for the next several years, reflecting spending on these major projects.

As a result of the Company having such a strong suite of projects, Petro-Canada will further focus its portfolio in 2007 to those projects and areas that can make a material difference, that balance the Company's risk profile and that can be executed effectively. As a result, the Company may divest smaller assets and interests in 2007.

Major Projects	TARGET ON-STREAM DATE
Buzzard	2007
Edmonton Refinery Conversion	2008
Montreal Refinery Coker	2009
Syria Gas Development	2010
MacKay River Expansion	2010
Fort Hills – Phase 1	2011

# Risk Management

## PETRO-CANADA'S RISK PROFILE

Petro-Canada's results are impacted by risk and management's strategy for handling risks. Petro-Canada characterizes and manages risks in four broad categories: business risks, market risks, operational risks and foreign risks. Within these categories, risks are listed in alphabetical order below. Management believes each major risk requires a unique response based on Petro-Canada's business strategy and financial tolerance. While some risks can be effectively managed through internal controls and business processes, others are managed through insurance and hedging. The Audit, Finance and Risk Committee of the Board of Directors has responsibility to oversee risk management.<sup>1</sup> The following describes Petro-Canada's approach to managing major risks.

## BUSINESS RISKS

### Counterparties

Petro-Canada is exposed to credit risk due to the uncertainty of business partners' or counterparties' ability to fulfil their obligations. The Company has internal credit policies and procedures that include financial assessments, exposure limits and processes to monitor and minimize the exposures against these limits. Where appropriate, Petro-Canada also uses netting and collateral arrangements to minimize risk.

### Environmental Regulations

Petro-Canada has always been subject to the impact of changing environmental regulations on its operations; however, the risk is considered to be increasing as related laws and regulations become more stringent in Canada and in other countries where Petro-Canada operates. Petro-Canada invests capital to satisfy new product specifications and/or address environmental issues. In 2007, the Company anticipates that it will invest \$100 million of its capital expenditure program toward regulatory compliance. As well, the Company conducts Life-Cycle Value Assessments (LCVA), a system to integrate and balance environmental, social and economic decisions for major projects. This process encourages the exploration of alternatives when considering the life-cycle of an asset or product from construction through to abandonment. The LCVA is a useful technique, but it cannot predict changes in environmental regulations. As a result, changes in environmental regulations may impact Petro-Canada's business results.

The Kyoto Protocol, effective in Canada since 2005, requires signatory nations to reduce their emissions of carbon dioxide and other greenhouse gases. The details of implementation of the Protocol in Canada have not been finalized. Depending on the specifics of the regulations, Petro-Canada may be required to reduce emissions of greenhouse gases from operations, to purchase emission-trading credits or pay for other types of offsets. The impact on Petro-Canada could result in substantially higher capital expenditures and/or operating expenses. The Government of Canada may also impose higher vehicle fuel efficiency standards. The impact of this action could be to decrease the demand for gasoline and diesel fuels sold by Petro-Canada and depress industry-wide margins for refined products. Through industry organizations, Petro-Canada works with a number of regulatory groups and government associations to find an approach that will minimize the negative financial impact of the greenhouse gas emission regulations on the Company, while still reducing emissions. The level of influence these efforts have on the Government of Canada's implementation plan may be quite limited.

### Government Regulations

Petro-Canada's operations are regulated by, and could be intervened upon by, a variety of governments around the world. Governments could impact the contracting of exploration and production interests, impose specific drilling obligations, and expropriate or cancel contract rights. Governments may also regulate prices of commodities or refined products, or intervene indirectly on prices through taxes, royalties and exploration rights.

Petro-Canada tries to mitigate the potentially disruptive impact of government regulations by selecting operating environments with stable governments and by maintaining respectful relationships with governments and regulators. Contact with regulators and governments usually occurs through the Company's management and/or regulatory affairs and government relations personnel. Petro-Canada aims to have regular, constructive communication with regulators and

<sup>1</sup> Further detail regarding the Audit, Finance and Risk Committee can be found in the AIF along with a copy of its Charter, attached as Schedule C.

governments so issues can be resolved in a mutually acceptable fashion. The Company also has a strong record of regulatory compliance within the jurisdictions where it operates. By virtue of Petro-Canada's integrated portfolio of businesses, the Company operates in many different jurisdictions and derives revenue from several categories of products. This diversification makes financial performance less sensitive to the action of any single government. Nevertheless, Petro-Canada has limited ability to influence regulations that may have a material adverse effect on the Company.

### **Licence to Operate**

Petro-Canada's oil and gas production and refining operations impact communities and surrounding environments. Those impacted can become concerned over the use of scarce resources, such as land and water, the perceived or real threat to human health, the potential impact on biodiversity, and/or possible societal changes to surrounding communities. Petro-Canada must secure and maintain formal regulatory approvals and licences to conduct its operations. In addition, broader societal acceptance of the Company's activities is necessary for resource development. An inability for Petro-Canada to secure local community support, necessary regulatory approvals and licences, and broader societal acceptance can result in projects being delayed or stopped, increasing project costs and damage to the Company's reputation. Lack of local community and stakeholder support can also lead to pressure to limit or shut down operations.

Petro-Canada manages this risk by applying a set of Principles for Responsible Investment and Operations to its businesses. These Principles provide a framework whereby Petro-Canada's operations around the world are conducted in a manner that is economically rewarding to all parties and recognized as being ethically, environmentally and socially responsible. These Principles and the Company's activities in support of them can be found on Petro-Canada's website at [www.petro-canada.ca](http://www.petro-canada.ca). Even though Petro-Canada is committed to following its Principles and respecting two-way dialogue with applicable stakeholders, there is no guarantee the Company will be granted the licences needed to operate projects within expected timelines or that its reputation with affected stakeholders will not be damaged.

### **Non-Operated Interests**

Petro-Canada has a significant interest in assets where the management of construction or operation is done by other companies. Business assets in which Petro-Canada has a major interest, but does not operate, include Hibernia (20% interest), Syncrude (12% interest), White Rose (27.5% interest) and Buzzard (29.9% interest). Joint venture executive committees manage major projects, so Petro-Canada does have some ability to influence these projects. As well, Petro-Canada has joint venture or other operating agreements, which specify the Company's expectations from third-party operators. Nevertheless, third-party operation and management of the Company's assets could adversely affect Petro-Canada's financial performance.

### **Project Execution**

Petro-Canada manages a variety of projects to support continuing operations and future growth. Petro-Canada's goal is to consistently deliver projects in alignment with expectations. Project execution risks include, but are not limited to, changes in project scope, labour availability and productivity, material and services availability and costs, design and construction errors, regulatory approvals, project management and operational capability. To mitigate these risks, Petro-Canada applies a project delivery management system, establishes strong project management teams, breaks large projects down into manageable components, builds on experience and existing technologies, works with all stakeholders on safety and environmental expectations, and conducts post-project reviews to improve project management and operational capabilities. Petro-Canada primarily delivers projects through engineering, procurement and construction (EPC) companies. Through the establishment of strong, internal project management teams, the Company establishes effective working relationships with EPC companies.

In 2006, Petro-Canada completed a number of projects, including converting refineries to produce cleaner burning fuels, expansion of the lubricants plant and bringing the Company-operated De Ruyter project in the North Sea on-stream. These projects represented \$1.7 billion of investment, which was completed on time and on budget. Nevertheless, the inability of Petro-Canada to execute projects as expected is a risk to the Company. Globally, there is a focus on execution and projects are tending to be larger and more complex at the same time as the pool of experienced personnel is declining. The Company has recognized the need to provide the organizational capability to successfully execute these projects and, as such, has been building its capabilities through recruiting and internal training; however, the inability to adequately source the staffing requirements could jeopardize successful project execution.

## Reserves Estimates

Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions. These include geoscientific interpretation, commodity prices, operating and capital costs, and historical production from properties. Petro-Canada has well-established, corporate-wide reserves booking practices that have been continuously improved for more than a decade. PricewaterhouseCoopers LLP, as contract internal auditor, has tested aspects of the non-engineering control processes Petro-Canada used in establishing reserves. As well, independent engineering firms assess a significant portion of reserves estimates every year. Over time, this means all of Petro-Canada's reserves estimates are assessed by external evaluators. The Board of Directors also reviews and approves the Company's annual reserves filings. More information on reserves booking practices can be found in the Company's AIF.

## Reserves Replacement<sup>1, 2</sup>

Petro-Canada's future cash flows from continuing operations are highly dependent on its ability to offset natural declines as reserves are produced. As basins mature, replacement of reserves becomes more challenging and expensive. In some geographic areas, the Company may choose to allow its reserves to decline if replacement is uneconomical, pursuing other reserves additions instead from successful exploration or acquisitions.

Petro-Canada's reserves objective is to fully replace proved reserves over a five-year period. In 2006, the Company replaced 134% of its production on a proved reserves basis, compared with 111% in 2005. The Company's five-year proved replacement ratio was 160% at year-end 2006. There is no assurance Petro-Canada will successfully replace reserves that are produced in any given year.

## MARKET RISKS

More detailed quantification of the impact of some of the following risks can be found in the earnings sensitivities table on page 5 of the Business Environment section in the MD&A.

### Commodity Prices

The prices of crude oil and natural gas fluctuate in response to market factors that are external to Petro-Canada. Commodity prices are volatile and influenced by factors such as supply and demand fundamentals, geopolitical events, OPEC decisions and weather. For historical commodity prices, please refer to page 4 of the Business Environment section in the MD&A. Changes in crude oil and natural gas prices affect the price that Petro-Canada receives for its upstream production. Commodity prices also impact the refined product margins realized in the Downstream business. Petro-Canada's ability to maintain product margins in an environment of higher feedstock costs is contingent upon the Company's ability to pass on higher costs to customers.

Petro-Canada generally does not hedge large volumes of production. Management believes commodity prices are volatile and difficult to predict. The business is managed so that the Company can substantially withstand the impact of a lower price environment while maintaining the opportunity to capture significant upside when the price environment is higher. However, commodity prices and margins may be hedged occasionally to capture opportunities that represent extraordinary value and/or to reduce commodity price risk on specific exposures. Certain Downstream physical transactions are routinely hedged for operational needs and to facilitate sales to customers.

### Foreign Exchange

Because energy commodity prices are primarily in U.S. dollars, Petro-Canada's revenue stream is affected by the Canada/U.S. exchange rate. As a result, the Company's earnings are negatively affected by a strengthening Canadian dollar. The Company is also exposed to fluctuations in other foreign currencies, such as the euro and the British pound. Generally, Petro-Canada does not hedge foreign exchange exposures, although the Company partially mitigates the U.S. dollar exposure by denominating the majority of its debt obligations in U.S. dollars. Foreign exchange exposure related to asset acquisitions or divestitures, or project capital expenditures, may be hedged on a case-by-case basis.

### Interest Rates

Petro-Canada targets a blend of fixed and floating rate debt. Generally, this strategy lets the Company take advantage of lower interest rates on floating debt, while matching overall debt maturities with the life of cash-generating assets. While the Company is exposed to fluctuations in the rate of interest it pays on floating rate debt, this interest rate exposure is within the Company's risk tolerance. Periodically, the Company reviews the proportion of fixed to floating rate debt issued.

<sup>1</sup> See legal notice on page 2 regarding oil and gas, and oil sands mining activities.

<sup>2</sup> Proved reserves replacement ratio is calculated by dividing the year-over-year net change in proved reserves, before deducting production, by the annual production over the same period. The reserves replacement ratio is a general indicator of the Company's reserves growth. It is only one of a number of metrics that can be used to analyse a company's upstream business.

### *Derivative Instruments*

Petro-Canada has a formal policy that prohibits the use of derivative instruments for speculative purposes. All derivative instruments entered into are for the purpose of mitigating identified price risks.

Petro-Canada continually monitors outstanding derivative instruments. This includes an assessment of fair values of all derivative instruments using independent third-party quotes to determine the value of each derivative instrument. The objectives of all price risk mitigation transactions are documented, and the effectiveness of each derivative instrument in offsetting the identified price risk is periodically assessed. Petro-Canada also limits the transaction term of its derivative instruments.

The Company applied mark-to-market accounting treatment to all derivative transactions that it entered into in 2006. Realized and unrealized gains and losses resulting from changes in the fair value of derivative instruments that do not qualify for hedge accounting are recognized in "Investment and Other Income." For derivative instruments that qualify for hedge accounting, Petro-Canada may elect to apply hedge accounting treatment.

During 2004, as part of the Company's acquisition of an interest in the Buzzard field in the U.K. sector of the North Sea, the Company entered into a series of derivative contracts related to the future sale of Dated Brent crude oil. The purpose of these transactions was to ensure value-added returns to Petro-Canada on this investment, even in the event of a material decrease in oil prices. These contracts effectively lock in an average forward price of approximately \$26 US/bbl on a volume of 35,840,000 bbls. This volume represents approximately 50% of the Company's share of estimated plateau production from July 1, 2007 to December 31, 2010. As at December 31, 2006, the Buzzard derivative instruments had a recognized mark-to-market unrealized loss of \$1,007 million after-tax, of which \$240 million was recognized in the income statement in 2006.

In 2006, other derivative instruments in place for refining supply and product purchases resulted in an increase in net earnings from continuing operations of about \$1 million after-tax, compared with an increase of about \$4 million in 2005.

### **OPERATIONAL RISKS**

Exploring for, developing, producing, refining, transporting and marketing oil, natural gas and refined products involve significant operational risks. These risks include situations such as well blowouts, fires, explosions, gaseous leaks, equipment failures, migration of harmful substances and oil spills. Any of these operational incidents, including events beyond the Company's control, could cause personal injury, environmental contamination, interruption of production, and/or damage and destruction of the Company's assets.

Petro-Canada manages operational risks primarily through a Total Loss Management (TLM) system that has standards to prevent losses. Regular TLM audits test compliance with these standards. The Company also has a Zero-Harm philosophy, a belief that injuries and illnesses, on and off the job, are foreseeable and preventable.

The Company also purchases insurance to transfer the financial impact of some operational risks to third-party insurers. On an annual basis, Petro-Canada management evaluates its operational risk exposures and adjusts its insurance coverage, including deductibles and limits. While Petro-Canada maintains insurance consistent with industry practices, the Company cannot and does not fully insure against all risks. Losses resulting from operational incidents could have an adverse impact on the Company.

Interruption to production at any one of Petro-Canada's facilities could result in an adverse financial impact; however, the risk of multiple facilities experiencing production interruptions at the same time is mitigated by having multiple large producing and upgrading assets in various geographic locations throughout the world.

### **FOREIGN RISKS**

Petro-Canada has significant operations in a number of countries that have varying political, economic and social systems. As a result, the Company's operations and related assets are subject to potential risks of actions by governmental authorities, internal unrest, war, political disruption, economic and legal sanctions (such as restrictions against countries that the U.S. government may deem to sponsor terrorism), and changes in global trade policies. The Company's operations may be restricted, disrupted or prohibited in any country in which these risks occur. Petro-Canada also has production in countries that are members of OPEC, which has resulted in, and may result in, the future for production volumes to be constrained by quotas.

The Company continually evaluates exposure in any one country in the context of total operations. Investment may be limited to avoid excessive exposure in any one country or region. The Company also purchases political risk insurance to partially mitigate certain political risks.

# Consolidated Financial Results

## ANALYSIS OF CONSOLIDATED EARNINGS AND CASH FLOW

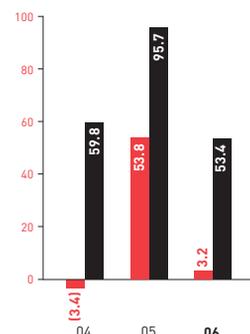
### Consolidated Financial Results

On January 31, 2006, Petro-Canada closed the sale of the Company's producing assets in Syria. These assets and associated results are reported as discontinued operations and are excluded from continuing operations.

### Shareholder Value

Shareholder value measures the change in the Petro-Canada share price plus dividend returns.

■ One-year return (%)  
■ Three-year return (%)



(millions of Canadian dollars, unless otherwise indicated)

	2006	2005	2004
<b>Net earnings</b>	<b>\$ 1,740</b>	<b>\$ 1,791</b>	<b>\$ 1,757</b>
Net earnings from discontinued operations	152	98	59
<b>Net earnings from continuing operations</b>	<b>\$ 1,588</b>	<b>\$ 1,693</b>	<b>\$ 1,698</b>
Gain on foreign currency translation <sup>1</sup>	1	73	63
Unrealized loss on Buzzard derivative contracts <sup>2</sup>	(240)	(562)	(205)
Gain on sale of assets	25	34	11
<b>Operating earnings from continuing operations<sup>3,4</sup></b>	<b>\$ 1,802</b>	<b>\$ 2,148</b>	<b>\$ 1,829</b>
Stock-based compensation	(31)	(66)	(11)
Insurance proceeds (surcharges) <sup>5</sup>	8	(75)	31
Income tax adjustments	(185)	22	13
Oakville closure costs	-	2	(46)
<b>Operating earnings from continuing operations adjusted for unusual items</b>	<b>\$ 2,010</b>	<b>\$ 2,265</b>	<b>\$ 1,842</b>
Earnings per share from continuing operations (dollars)			
- basic	\$ 3.15	\$ 3.27	\$ 3.21
- diluted	3.11	3.22	3.17
Earnings per share (dollars) - basic	\$ 3.45	\$ 3.45	\$ 3.32
- diluted	3.41	3.41	3.28
Cash flow from continuing operating activities before changes in non-cash working capital <sup>6,4</sup>	3,687	3,787	3,425
Cash flow from continuing operating activities before changes in non-cash working capital per share (dollars)	7.32	7.31	6.47
Debt	2,894	2,913	2,580
Cash and cash equivalents <sup>7</sup>	499	789	170
Average capital employed <sup>7</sup>	\$ 12,868	\$ 11,860	\$ 10,533
Return on capital employed (%) <sup>7</sup>	14.3	16.0	17.5
Operating return on capital employed (%) <sup>7</sup>	15.0	19.8	18.8
Return on equity (%) <sup>7</sup>	17.5	19.7	21.5

1 Foreign currency translation reflects gains or losses on U.S. dollar-denominated long-term debt not associated with the self-sustaining International business unit and the U.S. Rockies operations included in the North American Natural Gas business unit.

2 As part of its acquisition of an interest in the Buzzard field in the U.K. sector of the North Sea in June 2004, the Company entered into derivative contracts for half of its share of estimated production for 3½ years, starting July 1, 2007.

3 Operating earnings, which represent net earnings excluding gains or losses on foreign currency translation and on disposal of assets and the unrealized gains or losses associated with the Buzzard derivative contracts, are used by the Company to evaluate operating performance.

4 Operating earnings and cash flow from continuing operations do not have any standardized meaning prescribed by Canadian GAAP and, therefore, may not be comparable with the calculation of similar measures for other companies.

5 Insurance premium surcharges include accruals and surcharges for Oil Insurance Ltd. (OIL) and sEnergy Insurance Ltd. (sEnergy) policies. OIL is a mutual insurance company that insures against property damage in the energy sector. sEnergy was a mutual insurance company that provided business interruption and excess property insurance to the energy sector.

6 Cash flow, which is expressed before changes in non-cash working capital items relating to operating activities, is used by the Company to analyse operating performance, leverage and liquidity.

7 Includes discontinued operations.

## 2006 COMPARED WITH 2005

Operating earnings from continuing operations adjusted for unusual items decreased 11% to \$2,010 million in 2006, compared with \$2,265 million in 2005. Lower upstream production, declining realized natural gas prices and higher operating and exploration costs were partially offset by stronger realized crude oil prices.

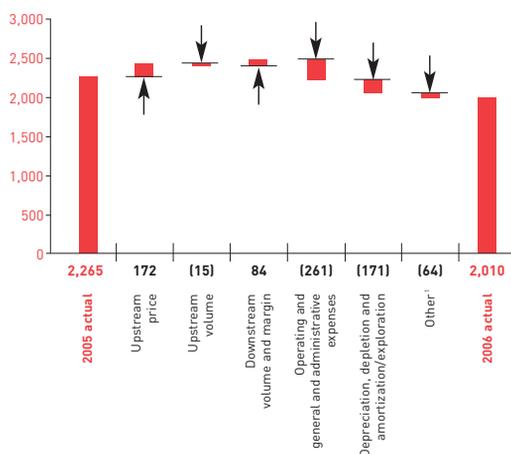
In 2006, operating earnings from continuing operations included a number of unusual items: \$185 million charge for income tax rate and other tax adjustments, \$37 million in insurance proceeds, a \$31 million charge related to the mark-to-market of stock-based compensation and a \$29 million insurance premium surcharge.

In 2005, operating earnings from continuing operations included a number of unusual items: a \$77 million insurance premium surcharge, a \$66 million charge related to the mark-to-market of stock-based compensation and a \$22 million positive adjustment related to income tax rate and other tax adjustments.

Net earnings from continuing operations in 2006 were \$1,588 million, down 6% compared with \$1,693 million in 2005, primarily due to lower production, declining realized natural gas prices and income tax adjustments, partially offset by lower realized losses on Buzzard derivative contracts. Net earnings from continuing operations included gains or losses on foreign currency translation, unrealized losses on Buzzard derivative contracts and gains on asset sales.

## 2006 Versus 2005 Factor Analysis

Operating Earnings from Continuing Operations Adjusted for Unusual Items  
(millions of dollars, after-tax)



<sup>1</sup> Other mainly includes interest expense, foreign exchange, changes in effective income tax rates and changes in upstream inventory levels.

## QUARTERLY INFORMATION

### Consolidated Quarterly Financial Results

(millions of Canadian dollars, unless otherwise indicated)

	2006				2005			
	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Quarter 1	Quarter 2	Quarter 3	Quarter 4
Total revenue from continuing operations	\$ 4,188	\$ 4,730	\$ 5,201	\$ 4,550	\$ 3,275	\$ 3,945	\$ 4,721	\$ 4,838
Operating earnings from continuing operations	202	532	597	471	427	476	597	648
Net earnings from continuing operations	54	472	678	384	110	322	593	668
Cash flow from continuing operating activities before changes in non-cash working capital	857	754	1,085	991	801	869	1,001	1,116
Earnings per share from continuing operations (dollars)								
– basic	\$ 0.11	\$ 0.93	\$ 1.36	\$ 0.77	\$ 0.21	\$ 0.62	\$ 1.14	\$ 1.29
– diluted	\$ 0.10	\$ 0.92	\$ 1.34	\$ 0.76	\$ 0.21	\$ 0.61	\$ 1.13	\$ 1.28
Earnings per share (dollars)								
– basic	\$ 0.40	\$ 0.93	\$ 1.36	\$ 0.77	\$ 0.23	\$ 0.66	\$ 1.19	\$ 1.38
– diluted	\$ 0.40	\$ 0.92	\$ 1.34	\$ 0.76	\$ 0.22	\$ 0.66	\$ 1.17	\$ 1.36

Revenue and net earnings variances from quarter to quarter resulted mainly from fluctuations in commodity prices and refinery cracking margins, the impact on production and processed volumes from maintenance and other shutdowns at major facilities, and the level of exploration drilling activity. For further analysis of quarterly results, refer to Petro-Canada's quarterly reports to shareholders available on the Company's website at [www.petro-canada.ca](http://www.petro-canada.ca).

# Liquidity and Capital Resources

## Summary of Cash Flows

<i>(millions of Canadian dollars)</i>	2006	2005	2004
<b>Cash flow from continuing operating activities</b>	<b>\$ 3,608</b>	<b>\$ 3,783</b>	<b>\$ 3,928</b>
Increase (decrease) in non-cash working capital related to continuing operating activities and other	79	4	(503)
<b>Cash flow from continuing operations</b>	<b>\$ 3,687</b>	<b>\$ 3,787</b>	<b>\$ 3,425</b>
Cash flow from discontinued operating activities	15	204	233
Increase (decrease) in non-cash working capital related to discontinued operating activities	2	41	(29)
<b>Cash flow</b>	<b>3,704</b>	<b>4,032</b>	<b>3,629</b>
Net cash inflows (outflows) from:			
investing activities before changes in non-cash working capital	(2,797)	(3,595)	(4,591)
financing activities before changes in non-cash working capital	(1,175)	(10)	(19)
(Increase) decrease in non-cash working capital	(22)	192	516
Increase (decrease) in cash and cash equivalents	<b>\$ (290)</b>	<b>\$ 619</b>	<b>\$ (465)</b>
<b>Cash and cash equivalents at end of year</b>	<b>\$ 499</b>	<b>\$ 789</b>	<b>\$ 170</b>
<b>Cash and cash equivalents – discontinued operations</b>	<b>\$ –</b>	<b>\$ 68</b>	<b>\$ 206</b>

In 2006, cash flow from continuing operations was \$3,687 million (\$7.32/share), compared with \$3,787 million (\$7.31/share) in 2005. The decrease in cash flow reflected lower operating earnings from continuing operations.

## Financial Ratios

	2006	2005	2004
Interest coverage from continuing operations <i>(times)</i> <sup>1</sup>			
Net earnings basis	19.2	17.9	20.0
EBITDAX basis	27.0	25.4	29.2
Cash flow basis	27.4	28.9	30.4
Debt-to-cash flow <i>(times)</i> <sup>2</sup>	0.8	0.8	0.8
Debt-to-debt plus equity <i>(%)</i>	21.7	23.5	22.8

1 Refer to the Glossary of Terms and Ratios on page 92 for methods of calculation.

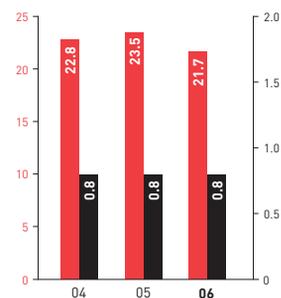
2 From continuing operations.

Petro-Canada's financing strategy is designed to maintain financial strength and flexibility to support profitable growth in all business environments. Two key measures that Petro-Canada uses to measure the Company's overall financial strength are debt-to-cash flow from continuing operations and debt-to-debt plus equity. Petro-Canada's debt-to-cash flow from continuing operations ratio, the key short-term measure, was 0.8 times at December 31, 2006 and 2005. This was well within the Company's target range of no more than 2.0 times. Debt-to-debt plus equity, the long-term measure for capital structure, was 21.7% at year-end 2006, down from 23.5% at year-end 2005. This was below the target range of 25% to 35% for both years, providing the financial flexibility to fund the Company's capital program and profitable growth opportunities. Financial covenants associated with the Company's various debt arrangements are reviewed regularly and controls are in place to ensure compliance with these covenants.

### Key Debt Ratios

Petro-Canada has the financial discipline and flexibility to manage changing market dynamics and pursue new growth opportunities.

- Debt-to-debt plus equity *(%)*
- Debt-to-cash flow *(times)*



## OPERATING ACTIVITIES

Excluding cash and cash equivalents, short-term notes payable and the current portion of long-term debt, the operating working capital deficiency, including discontinued operations, was \$1,014 million at December 31, 2006, compared with an operating working capital deficiency, including discontinued operations, of \$697 million at December 31, 2005. The working capital deficiency, including discontinued operations, was higher primarily due to a decrease in accounts receivable and an increase in accounts payable.

## INVESTING ACTIVITIES

### Capital and Exploration Expenditures

(millions of Canadian dollars)	2007 Outlook <sup>1</sup>	2006	2005	2004
<b>Upstream</b>				
North American Natural Gas	\$ 780	\$ 788	\$ 713	\$ 666
East Coast Oil	210	256	314	275
Oil Sands	770	377	772	397
International <sup>2</sup>	865	760	696	1,707 <sup>3</sup>
	<b>\$ 2,625</b>	<b>\$ 2,181</b>	<b>\$ 2,495</b>	<b>\$ 3,045</b>
<b>Downstream</b>				
Refining and Supply	\$ 1,215	\$ 1,038	\$ 883	\$ 656
Sales and Marketing	150	142	108	171
Lubricants	25	49	62	12
	<b>\$ 1,390</b>	<b>\$ 1,229</b>	<b>\$ 1,053</b>	<b>\$ 839</b>
<b>Shared Services</b>				
	<b>\$ 35</b>	<b>\$ 24</b>	<b>\$ 12</b>	<b>\$ 9</b>
<b>Total property, plant and equipment and exploration</b>				
	<b>\$ 4,050</b>	<b>\$ 3,434</b>	<b>\$ 3,560</b>	<b>\$ 3,893</b>
Deferred charges and other assets	10	50	70	36
Acquisition of Prima Energy Corporation	-	-	-	644
<b>Total continuing operations</b>				
	<b>\$ 4,060</b>	<b>\$ 3,484</b>	<b>\$ 3,630</b>	<b>\$ 4,573</b>
Discontinued operations	\$ -	\$ 1	\$ 46	\$ 62
<b>Total</b>				
	<b>\$ 4,060</b>	<b>\$ 3,485</b>	<b>\$ 3,676</b>	<b>\$ 4,635</b>

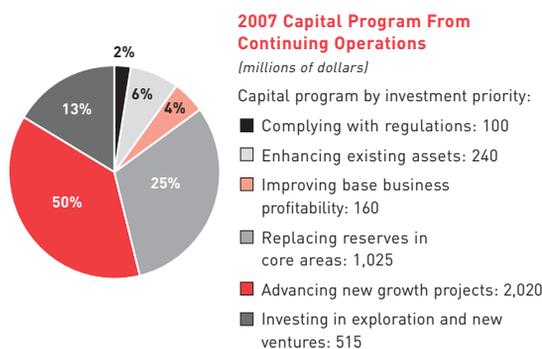
<sup>1</sup> The 2007 outlook was previously released on December 14, 2006.

<sup>2</sup> International excludes capital expenditures related to the Syrian producing assets, which are reflected as discontinued operations.

<sup>3</sup> Includes \$1,218 million for the Buzzard acquisition.

Capital and exploration expenditures were \$3,485 million in 2006, down 5% compared with \$3,676 million in 2005, mainly reflecting lower investment in Oil Sands assets.

In 2007, spending on new growth projects is expected to increase. More than 60% of planned capital expenditures support delivering profitable new growth, and funding exploration and new ventures. This estimate is up from nearly 53% in these categories in 2006. The remaining 40% of the 2007 planned capital expenditures are directed toward replacing reserves in core areas, enhancing existing assets, improving base business profitability and complying with regulations. The regulatory compliance portion of the program was greater in 2006, primarily reflecting expenditures to produce cleaner burning fuels at Downstream refineries.



## FINANCING ACTIVITIES AND DIVIDENDS

### Sources of Capital Employed

(millions of Canadian dollars)

	2006	2005	2004
Short-term notes payable	\$ -	\$ -	\$ 299
Long-term debt, including current portion	2,894	2,913	2,281
Shareholders' equity	10,441	9,488	8,739
<b>Total</b>	<b>\$ 13,335</b>	<b>\$ 12,401</b>	<b>\$ 11,319</b>

Total debt decreased to \$2,894 million at December 31, 2006, compared with \$2,913 million at the previous year end. The decrease in debt was due to capital lease repayments made in 2006.

### 2006 Financing Activities

During the fourth quarter, Petro-Canada increased its syndicated committed credit facilities to \$2,200 million from \$2,000 million. At December 31, 2006, the Company also had bilateral demand credit facilities of \$829 million. A total of \$1,444 million of the credit facilities was used for letters of credit and overdraft coverage at December 31, 2006. The syndicated facilities also provide liquidity support to Petro-Canada's commercial paper program. No commercial paper was outstanding at year-end 2006. The Company will continue to use its cash position, draw on bank lines and issue commercial paper or long-term notes as necessary to meet working capital and other financing requirements. Petro-Canada plans to meet remaining debt repayment commitments from a combination of cash flow and debt refinancing.

The Company's unsecured long-term debt securities are rated Baa2 by Moody's Investors Service, BBB by Standard & Poor's and A (low) by Dominion Bond Rating Service. The Company's long-term debt ratings remained unchanged from year-end 2005.

Petro-Canada's short-term debt securities are rated R-1 (low) by Dominion Bond Rating Service. This rating remains unchanged from year-end 2005.

### Returning Cash to Shareholders

Petro-Canada's first priority use of cash is to fund its capital program and profitable growth opportunities, and then to look to return cash to shareholders through dividends and a share buyback program.

Petro-Canada regularly reviews its dividend strategy to ensure the alignment of the dividend policy with shareholder expectations, and financial and growth objectives. Consistent with these objectives, on December 14, 2006, the Company declared a 30% increase in its quarterly dividend to \$0.13/share, commencing with the dividend payable April 1, 2007. Total dividends paid in 2006 were \$201 million, compared with \$181 million in 2005.

In 2004, Petro-Canada initiated a NCIB program, which was renewed in 2005 and 2006. The current program, which extends to June 21, 2007, entitles the Company to purchase up to 5% of the outstanding common shares, subject to certain conditions. The level of activity in the NCIB program during the first two quarters of 2006 reflected the use of proceeds from the sale of the mature Syrian assets to buy back shares.

Period	Shares Repurchased		Average Price		Total Cost	
	2006	2005	2006	2005	2006	2005
Full year	19,778,400	8,333,400	\$ 51.10	\$ 41.54	\$ 1,011 million	\$ 346 million

### Off Balance Sheet

The Company has certain retail licensee and wholesale marketing agreements that would constitute variable interest entities as described in Note 26 to the Consolidated Financial Statements. These entities are not consolidated because Petro-Canada is not the primary beneficiary and, therefore, consolidation is not required. The Company's maximum exposure to losses from these arrangements would not be material. Other off balance sheet activities are limited to the accounts receivable securitization program, which does not meet the criteria for consolidation and guarantees.

### Pension Plans

At year-end 2006, Petro-Canada's defined benefit pension plans were underfunded by \$300 million, compared with an underfunded position of \$378 million at year-end 2005. For both the defined benefit and defined contribution pension plans, the Company made cash contributions of \$114 million and recorded a pension expense of \$91 million before-tax in 2006. This compares with \$112 million of cash contributions and \$78 million before-tax of pension expense in 2005. The Company expects to make pension contributions of approximately \$115 million in 2007.

### Contractual Obligations – Summary

<i>(Millions of Canadian dollars)</i>	PAYMENTS DUE BY PERIOD				
	Total	2007	2008-2009	2010-2011	2012 and thereafter
Unsecured debentures and senior notes <sup>1</sup>	\$ 6,260	\$ 175	\$ 351	\$ 351	\$ 5,383
Capital lease obligations <sup>1</sup>	142	15	21	21	85
Operating leases	1,149	492	246	174	237
Transportation agreements	1,741	215	358	238	930
Product purchase/delivery obligations <sup>2</sup>	2,539	280	375	275	1,609
Exploration work commitments <sup>3</sup>	132	88	36	8	–
Asset retirement obligations	3,481	67	106	126	3,182
Other long-term obligations <sup>4,5</sup>	2,756	197	853	393	1,313
<b>Total contractual obligations</b>	<b>\$ 18,200</b>	<b>\$ 1,529</b>	<b>\$ 2,346</b>	<b>\$ 1,586</b>	<b>\$ 12,739</b>

1 Obligations include related interest. For further details, see Note 18 to the 2006 Consolidated Financial Statements.

2 Excludes supply purchase agreements contracted at market prices of \$11,400 million, where the products could reasonably be re-sold into the market.

3 Excludes other amounts related to the Company's expected future capital spending. Capital spending plans are reviewed and revised annually to reflect Petro-Canada's strategy, operating performance and economic conditions. For further information regarding future capital spending plans, refer to the business segment and investing activities discussions of the 2006 MD&A.

4 Includes processing agreement with Suncor Energy Inc., receivables securitization program, pension funding obligations for the periods prior to the Company's next required pension plan valuation and other obligations. Pension obligations beyond the next required pension valuation date were excluded due to the uncertainty as to the amount or timing of these obligations.

5 Petro-Canada is involved in litigation and claims associated with normal operations. Management is of the opinion that any resulting settlements would not materially affect the financial position of the Company. The table excludes amounts for these contingencies due to the uncertainty as to the amount or timing of any settlements.

During 2006, Petro-Canada's total contractual obligations increased by approximately \$1.5 billion, mainly due to an increase in the estimate of asset retirement obligations, additional product purchase obligations and operating lease commitments.

# Upstream

Petro-Canada's upstream operations consisted of four business segments in 2006: North American Natural Gas, with current production in Western Canada and the U.S. Rockies; East Coast Oil, with three major developments offshore Newfoundland and Labrador; Oil Sands operations in Northeast Alberta; and International, where the Company is active in three core areas: Northwest Europe, North Africa/Near East and Northern Latin America.

The diverse asset base provides a balanced portfolio and a platform for long-term growth. In 2007, Petro-Canada is consolidating its East Coast Oil and International businesses. The purpose of this consolidation is to leverage and grow the capabilities of similar operations.



Wildcat Hills gas plant in Alberta



Terra Nova Floating Production Storage and Offloading (FPSO) vessel in Newfoundland and Labrador



Mackay River *in situ* oil sands plant in northern Alberta



De Ruyter platform in the North Sea

## NORTH AMERICAN NATURAL GAS

### BUSINESS SUMMARY AND STRATEGY

North American Natural Gas explores for and produces natural gas, and crude oil and natural gas liquids (NGL) in Western Canada and the U.S. Rockies. This business also markets natural gas in North America and has established resources in the Mackenzie Delta/Corridor and Alaska.

The North American Natural Gas strategy is to be a significant market participant by accessing new and diverse natural gas supply sources in North America. Key features of the strategy include:

- targeting 75% to 80% reserves replacement
- transitioning further into unconventional gas plays
- optimizing core properties in Western Canada and developing CBM and tight gas in the U.S. Rockies
- increasing the focus on exploration
- developing liquefied natural gas (LNG) import capacity at Gros-Cacouna, Quebec
- building the northern resource base for long-term growth

### North American Natural Gas Financial Results

(millions of Canadian dollars)

	2006	2005	2004
<b>Net earnings</b>	<b>\$ 405</b>	<b>\$ 674</b>	<b>\$ 500</b>
Gain on sale of assets	3	14	-
<b>Operating earnings</b>	<b>\$ 402</b>	<b>\$ 660</b>	<b>\$ 500</b>
Insurance premium surcharges	(1)	(4)	-
Income tax adjustments	6	28	7
<b>Operating earnings adjusted for unusual items</b>	<b>\$ 397</b>	<b>\$ 636</b>	<b>\$ 493</b>
Cash flow from operating activities before changes in non-cash working capital	<b>\$ 739</b>	\$ 1,193	\$ 882
Expenditures on property, plant and equipment and exploration	<b>\$ 788</b>	\$ 713	\$ 666
Total assets	<b>\$ 4,151</b>	\$ 3,763	\$ 3,477

## 2006 COMPARED WITH 2005

North American Natural Gas contributed \$397 million of operating earnings adjusted for unusual items, down considerably from \$636 million in 2005. Weak natural gas prices, lower Western Canada production, increased operating costs, higher exploration expenses and higher depreciation, depletion and amortization were partially offset by higher U.S. Rockies production.

Net earnings for North American Natural Gas were \$405 million in 2006, down from \$674 million in 2005. Net earnings in 2006 included a \$6 million income tax adjustment, a \$3 million gain on sale of assets and a \$1 million insurance premium surcharge. Net earnings in 2005 included a \$14 million gain on sale of assets, a \$4 million insurance premium surcharge and a \$28 million positive adjustment to income tax rate and other tax adjustments.

Oil and natural gas production averaged 701 million cubic feet/day of natural gas equivalent (MMcfe/d) in 2006, down from 756 MMcfe/d in 2005, as natural declines in Western Canada were partially offset by U.S. Rockies production growth. Natural gas commodity prices declined in 2006. The North American realized natural gas price averaged \$6.85/Mcf in 2006, down 19% from \$8.47/Mcf in 2005.

## 2006 OPERATING REVIEW AND STRATEGIC INITIATIVES

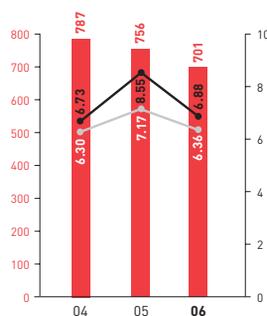
The North American Natural Gas business is positioning for the future with an increased focus on unconventional gas plays, acquisition of land in the Far North and progress on the proposed Quebec LNG project.

### 2006 Operating Review

#### North American Natural Gas Production and Realized Natural Gas Price

Western Canada natural declines more than offset the addition of U.S. Rockies production in 2006.

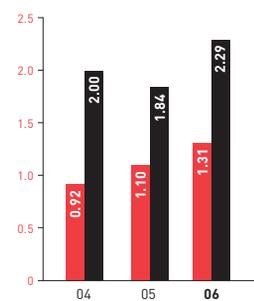
- Western Canada and U.S. Rockies production net (MMcfe/d)
- Western Canada realized natural gas price (\$/Mcf)
- U.S. Rockies realized natural gas price (\$/Mcf)



#### North American Natural Gas Operating and Overhead Costs

A 19% increase in Western Canada costs reflected general industry-wide cost pressures combined with lower production. U.S. Rockies costs increased due to the increasing number of wells and general industry-wide cost pressures.

- Western Canada operating and overhead costs (\$/Mcf)
- U.S. Rockies operating and overhead costs (\$/Mcf)



	2006	2005	2004
Production net (MMcfe/d)			
Western Canada	646	704	764
U.S. Rockies	55	52	23 <sup>1</sup>
Total North American Natural Gas production net	701	756	787
Western Canada realized natural gas price (\$/Mcf)	\$ 6.88	\$ 8.55	\$ 6.73
U.S. Rockies realized natural gas price (\$/Mcf)	\$ 6.36	\$ 7.17	\$ 6.30
Western Canada operating and overhead costs (\$/Mcf)	\$ 1.31	\$ 1.10	\$ 0.92
U.S. Rockies operating and overhead costs (\$/Mcf)	\$ 2.29	\$ 1.84	\$ 2.00

<sup>1</sup> U.S. Rockies production in 2004 is from the date of acquisition in July 2004.

### Western Canada

Western Canada natural gas production averaged 646 MMcfe/d in 2006, down 8% from 704 MMcfe/d in 2005. Exploration and development drilling activity in Western Canada resulted in 393 successful wells (gross), for an overall success rate of 93% in 2006. Western Canada operating and overhead costs were \$1.31/Mcfe in 2006, up from \$1.10/Mcfe in the previous year. The operating and overhead cost increase in Western Canada reflected general industry-wide cost pressures for materials, fuel and labour, combined with lower production.

### U.S. Rockies

U.S. Rockies natural gas production averaged 55 MMcfe/d in 2006, up 6% from 52 MMcfe/d in 2005. The increase reflected natural gas breakthrough at the Wild Turkey CBM field. Exploration and development drilling activity in the U.S. Rockies during 2006 resulted in more than 280 gross wells, down from the 300 wells in 2005. In addition, Petro-Canada obtained 396 permits for new CBM wells in 2006, with 363 applications submitted for consideration.

Most of the new CBM wells are currently in the de-watering phase. U.S. Rockies operating and overhead costs were \$2.29/Mcfe in 2006, compared with \$1.84/Mcfe in 2005. This increase reflected costs associated with the increasing number of wells, along with general industry-wide cost pressures.

## **2006 Strategic Initiatives**

In Western Canada, the Company commenced its planned shallow tight gas drilling program in the Medicine Hat area, and drilled more than 290 wells in 2006. The business expects to drill another 270 wells in 2007. In the southern Alberta Foothills, Petro-Canada successfully fulfilled the conditions required to earn a 60% working interest in the Sullivan natural gas field. The Company plans to seek regulatory approval in early 2007 to proceed with a multi-well development program in the Sullivan field. As part of the Company's ongoing optimization of its portfolio of assets, Petro-Canada completed the sale of its 31% working interest in the Brazeau plant and the majority of its 10% working interest in the West Pembina plant in early 2007.

In the U.S. Rockies, Petro-Canada is targeting increased CBM production with the Wild Turkey, North Shell Draw, Cedar Draw and Kingsbury projects. Increased CBM natural gas production follows a period of de-watering, which lowers the pressure in the coal seams, allowing natural gas breakthrough and production. Delays in obtaining CBM water treatment permits in 2005 pushed back the gas production increase in 2006. In February 2006, water treatment permits required for wells planned in 2005 and 2006 were approved. With water treatment permits in place, the U.S. Rockies continued to ramp up coal de-watering. Natural gas breakthrough at the Wild Turkey field occurred in the third quarter of 2006, with net production reaching 17 MMcf/d in late December. The Company continues to drill in the Denver-Julesburg Basin for natural gas from tight sands. Petro-Canada expects to double U.S. Rockies production to 100 MMcfe/d net by the end of 2007.

Furthering the strategic shift to increased unconventional production in the first half of 2006, the Company acquired approximately 50,000 net exploration acres of tight gas prone land for future development, including approximately 36,000 net acres in the Uinta Basin in eastern Utah.

During 2006, the Company continued to position itself for long-term North American supply by building its land position in Alaska and by participating in the drilling of an exploration well. At state and federal lease sales in 2006, Petro-Canada and its partners, Anadarko Petroleum Corporation and BG Group, were successful bidders on approximately 412,000 gross acres in the Alaska Foothills (a portion of this acreage remains subject to state title verification), giving each company a net land position in the Alaska Foothills of approximately one million acres, including option acreage.

Early in 2006, Petro-Canada and FEX L.P. (a subsidiary of Talisman Energy Inc.) reached a pooling agreement for the joint exploration of acreage in the National Petroleum Reserve-Alaska (NPR-A). As a result of this agreement, Petro-Canada obtained a 30% interest in the Aklaq-2 exploration well, which was drilled in the first quarter of 2006 and found to have hydrocarbons in quantities that were not commercially economical. In the latter part of 2006, FEX and Petro-Canada acquired 48 leases, or 562,000 gross acres, at the NPR-A lease sale for \$10.4 million US and subsequently pooled the majority of their NPR-A leaseholdings, covering approximately 1.2 million gross acres. As a result, in jointly held NPR-A acreage with FEX, Petro-Canada's net acreage position is just over 500,000 acres.

Consistent with the Company's strategy to build long-term resources in Canada's North, Petro-Canada made an offer to acquire Canada Southern Petroleum with interests in lands in the Arctic islands. The offer was unsuccessful; however, the Company remains the largest landholder in Arctic island gas and will continue to look for opportunities to consolidate its interests in the North.

A public hearing on the proposed Gros-Cacouna LNG re-gasification terminal in Quebec was held during the second quarter of 2006. The Company expects to receive a regulatory decision in 2007.

Capital expenditures in 2006 totalled \$788 million, with \$532 million for exploration and development of natural gas in Western Canada, \$145 million for U.S. Rockies exploration and development and \$111 million for other natural gas opportunities in North America.

## OUTLOOK

### Production expectations in 2007

- production is expected to average about 660 MMcfe/d net of natural gas, crude oil and NGL
- unconventional gas production is expected to be about 25% of production

### Action plans in 2007

- drill approximately 360 gross wells in Western Canada and approximately 300 gross wells in the U.S. Rockies
- advance long-term opportunities in Northern Canada and Alaska

- advance the re-gasification project at Gros-Cacouna to a project decision point

### Capital spending plans in 2007

- approximately \$400 million for replacing reserves in Western Canada core areas
- approximately \$230 million directed to exploration in Western Canada, the U.S. Rockies and the Far North
- approximately \$115 million for growth opportunities in the U.S. Rockies
- approximately \$45 million for maintenance

The shift to longer term projects, as well as declines in Western Canada, are expected to result in approximately a 6% drop in production in 2007, compared with 2006. In 2007, about 25% of the North American Natural Gas capital spending program is expected to go to development of unconventional sources, including U.S. Rockies CBM and deep tight gas, and infill drilling in the Medicine Hat area. At the same time, the business is expected to continue with exploration.

The Company will also continue to advance long-term supply opportunities. In the Alaska NPR-A area, the Company plans to start testing exploration lands by drilling up to three wells in 2007. As well, Petro-Canada expects to continue to advance the Gros-Cacouna LNG project. The Company, along with its partner, TransCanada PipeLines Limited, is aiming to secure regulatory approval in 2007. A joint provincial and federal government public review and consultation process took place in 2006.

[Link to Petro-Canada's Corporate and Strategic Priorities](#)

The North American Natural Gas business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2006 and goals for 2007.

	2006 RESULTS	2007 GOALS
<b>Delivering Profitable Growth with a Focus on Operated, Long-Life Assets</b>	<ul style="list-style-type: none"> <li>• drilled 393 gross wells in Western Canada, including 291 wells in the Medicine Hat region<sup>1</sup></li> <li>• drilled more than 280 gross wells, added 50,000 net acres of tight gas prone land and continued to increase CBM well de-watering in the U.S. Rockies</li> <li>• completed regulatory hearing for the LNG facility at Gros-Cacouna</li> <li>• increased land position in Alaska to 1.5 million net acres of leased and option lands</li> </ul>	<ul style="list-style-type: none"> <li>• transition further into unconventional gas plays</li> <li>• optimize opportunities around core assets</li> <li>• double U.S. Rockies production to 100 MMcfe/d net by year-end 2007</li> <li>• shift focus from developing around existing production to exploring in new areas</li> <li>• receive regulatory decision for the LNG facility at Gros-Cacouna</li> <li>• advance exploration prospects in the Mackenzie Delta/Corridor and Alaska</li> </ul>
<b>Driving For First Quartile Operation of Our Assets</b>	<ul style="list-style-type: none"> <li>• achieved better than 98% reliability at Western Canada facilities</li> <li>• successfully conducted major turnaround at the Hanlan gas plant, with no air licence exceedances</li> </ul>	<ul style="list-style-type: none"> <li>• sustain reliability performance</li> <li>• continue to leverage costs through strategic alliances and preferred suppliers</li> </ul>
<b>Continuing To Work At Being A Responsible Company</b>	<ul style="list-style-type: none"> <li>• achieved record TRIF in Western Canada, a 40% decrease compared with 2005</li> <li>• improved employee and contractor safety culture through behaviour-based safety programs</li> <li>• proactively remediated and reclaimed old sites</li> <li>• achieved record low regulatory compliance exceedances</li> </ul>	<ul style="list-style-type: none"> <li>• continue to focus on TRIF and maintain low regulatory exceedances</li> <li>• complete the roll out of behaviour-based safety for employees and contractors</li> <li>• drive for continuous improvement in contractor safety performance</li> <li>• proactively remediate and reclaim old sites</li> </ul>

<sup>1</sup> Includes wells only where Petro-Canada has a working interest.

# EAST COAST OIL

## BUSINESS SUMMARY AND STRATEGY

Petro-Canada is positioned in every major oil development off Canada's East Coast. The Company holds a 20% interest in Hibernia and a 27.5% interest in White Rose, and is the operator with a 34% interest in Terra Nova.

The East Coast Oil strategy is to improve reliability and sustain profitable production well into the next decade. Key features of the strategy include:

- delivering top quartile operating performance
- sustaining profitable production through reservoir extensions and add-ons
- pursuing high potential development projects

### East Coast Oil Financial Results

(millions of Canadian dollars)

	2006	2005	2004
<b>Net earnings and operating earnings</b>	<b>\$ 934</b>	<b>\$ 775</b>	<b>\$ 711</b>
Insurance premium surcharges	(9)	(25)	-
Income tax adjustments	37	(2)	3
Terra Nova insurance proceeds	22	2	31
<b>Operating earnings adjusted for unusual items</b>	<b>\$ 884</b>	<b>\$ 800</b>	<b>\$ 677</b>
Cash flow from operating activities before changes in non-cash working capital	\$ 1,163	\$ 1,062	\$ 993
Expenditures on property, plant and equipment and exploration	\$ 256	\$ 314	\$ 275
Total assets	\$ 2,465	\$ 2,442	\$ 2,265

## 2006 COMPARED WITH 2005

East Coast Oil contributed \$884 million of operating earnings adjusted for unusual items, up 11% from \$800 million in 2005. Strong realized prices were partially offset by lower production and increased operating expense.

Net earnings for East Coast Oil were \$934 million in 2006, up from \$775 million in 2005. Net earnings in 2006 included a \$37 million income tax adjustment, \$22 million of insurance proceeds related to mechanical failures on the Terra Nova FPSO vessel and a \$9 million insurance premium surcharge. Net earnings in 2005 included a \$25 million insurance premium surcharge.

In 2006, realized crude oil prices remained strong, while production decreased due to the early shutdown and planned dry dock turnaround of the Terra Nova FPSO. East Coast Oil realized crude prices averaged \$71.12/bbl in 2006, up from \$63.15/bbl in 2005. Petro-Canada's share of east coast oil production averaged 72,700 b/d in 2006, down from 75,300 b/d in 2005. Lower Terra Nova production was partially offset by the addition of White Rose production.

## 2006 OPERATING REVIEW AND STRATEGIC INITIATIVES

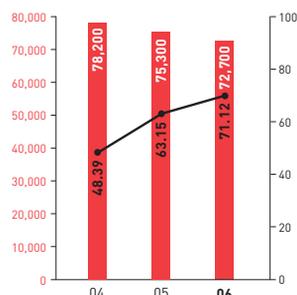
In 2006, East Coast Oil delivered record operating earnings of \$934 million. White Rose ramped up production, averaging 88,000 b/d gross (24,200 b/d net), Hibernia continued to operate reliably and Terra Nova underwent its planned dry dock turnaround for regulatory inspections and reliability improvements.

### 2006 Operating Review

#### East Coast Oil Production and Realized Crude Price

Realized crude prices remained strong, while production decreased due to the planned Terra Nova turnaround in 2006.

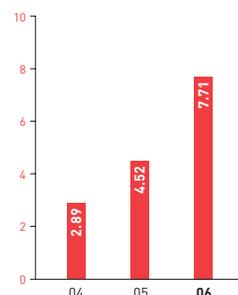
- East Coast Oil production net (b/d)
- Average realized crude price (\$/bbl)



#### East Coast Oil Operating and Overhead Costs

Operating costs increased as a result of the Terra Nova turnaround.

- East Coast operating and overhead costs (\$/bbl)



	2006	2005	2004
Production net (b/d)			
Hibernia	35,700	39,800	40,800
Terra Nova	12,800	33,700	37,400
White Rose	24,200	1,800	–
Total East Coast Oil production net	72,700	75,300	78,200
Average realized crude price (\$/bbl)	\$ 71.12	\$ 63.15	\$ 48.39
Operating and overhead costs (\$/bbl)	\$ 7.71	\$ 4.52	\$ 2.89

Hibernia production averaged 178,500 b/d gross (35,700 b/d net) in 2006, down from 199,000 b/d gross (39,800 b/d net) in 2005. The Hibernia platform continued to operate at first quartile levels during 2006, with lower production reflecting normal reservoir decline rates. Early in 2007, Hibernia encountered a mechanical failure on one of the platform's main power generators, thereby reducing production. While repairs are being completed, it is expected that Hibernia production will be in the range of 100,000 b/d to 110,000 b/d gross (20,000 b/d to 22,000 b/d net) for January and part of February 2007. To mitigate the impact of the main power generator repair on production, the operator advanced the planned third quarter turnaround. The planned Hibernia 30-day turnaround is expected to start in mid-February 2007.

At Terra Nova, production averaged 37,600 b/d gross (12,800 b/d net), down considerably from 99,100 b/d gross (33,700 b/d net) in 2005. Early in 2006, the first production well came on-stream in the Far East Block of the Terra Nova field. Terra Nova had a challenging year when its planned maintenance turnaround was advanced following the mechanical failure of the second of two main power generators. The completion of regulatory inspections and reliability improvements was expected to last up to 90 days, but was extended to complete necessary work. The reliability work included a 50% increase in onboard living quarters to support increased routine maintenance, repairs to gearboxes attached to two power generators and improvements to the gas compression system. In November, oil production from the Terra Nova field resumed. Petro-Canada's share of the total cost of the turnaround was approximately \$77 million. In December 2006, the Terra Nova FPSO encountered a mechanical issue in a swivel on the turret system that supports water injection to the reservoir. A temporary fix was completed in late December and production returned to normal rates in excess of 100,000 b/d gross (34,000 b/d net). Full repair of the swivel is currently planned during a turnaround in the summer of 2008. The Terra Nova project reached tier one payout in the fourth quarter of 2005. As a result, royalty payments at Terra Nova increased from 5% of gross revenues to 30% of net revenues.

White Rose operated reliably in 2006, ramping up production to average 88,000 b/d gross (24,200 b/d net), compared with 6,500 b/d gross (1,800 b/d net) in 2005. The 2006 results reflected a full year of operation at White Rose.

East Coast Oil operating and overhead costs averaged \$7.71/bbl in 2006, compared with \$4.52/bbl in 2005. Operating costs for East Coast Oil increased as a result of the Terra Nova turnaround, excluding insurance premium surcharges and startup costs for White Rose.

## 2006 Strategic Initiatives

In April 2006, Petro-Canada and its partners in the Hebron development suspended negotiations with the Government of Newfoundland and Labrador and demobilized the Hebron project team after failing to reach a development agreement. Petro-Canada continues to consider Hebron a high quality asset. While project activities have been suspended at this time, Petro-Canada and its project partners remain positive that the project could proceed at a future date with the conclusion of a definitive agreement with the provincial government.

At Hibernia, a delineation well was drilled to assess the growth potential of the Southern Extension of the Hibernia reservoir in late 2005. A development plan update for the Southern Extension was filed with the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) in May 2006. The partners originally expected to receive regulatory approval of the development application in 2006, so that first production from the Southern Extension could be brought on in 2007. In January 2007, the Government of Newfoundland and Labrador rejected the decision report of the C-NLOPB to approve the development of the Hibernia Southern Extension and asked the applicants for additional information. Petro-Canada and its partners are reviewing the decision.

In 2006, the West White Rose 0-28 and North Amethyst K-15 delineation wells were drilled in the west and southwest sections of the field, respectively. The White Rose 0-28 well revealed a 280-metre oil column in a multi-layered reservoir and the White Rose North Amethyst K-15 well revealed a 50- to 55-metre oil column in the Ben Nevis Avalon formation with high reservoir quality. The Company and its partner are assessing the development options for both of these add-on opportunities. Also in 2006, front-end engineering and design (FEED) began on the White Rose Southern Extension. This pool, discovered in 2003, is expected to be developed as a subsea tie-back to the SeaRose FPSO. Subject to regulatory approval, production could begin in late 2009.

Capital expenditures for exploration and development of crude oil offshore Canada's East Coast were \$256 million in 2006, including \$106 million for the planned Terra Nova dry dock turnaround and development drilling, \$88 million related to the development of the White Rose oilfield, \$51 million for ongoing activities at Hibernia and \$11 million for other East Coast Oil growth opportunities.

## OUTLOOK

### Production expectations in 2007

- production is expected to average 87,000 b/d net, reflecting a 30-day planned turnaround at Hibernia and a 16-day planned turnaround at White Rose

### Growth plans

- achieve 90% operating performance at Terra Nova
- continue delineation drilling of Terra Nova's Far East Block
- conduct delineation drilling and preliminary analysis of development options for the West White Rose Block at the White Rose field

- advance Hibernia Southern Extension development plan discussions with the Government of Newfoundland and Labrador
- complete FEED on the South White Rose Extension. Project sanction will be subject to regulatory approval
- complete FEED and submit development plan to the C-NLOPB on the North Amethyst discovery at White Rose with project sanction, subject to regulatory approval, by the end of 2007

### Capital spending plans in 2007

- approximately \$210 million is expected to be spent on drilling to replace reserves at Hibernia, Terra Nova and White Rose, and for delineation of Terra Nova's Far East Block

East Coast Oil production is expected to be about 87,000 b/d net in 2007, compared with 72,700 b/d net in 2006. The 2007 production estimate reflects the return of Terra Nova production and higher volume forecasts at White Rose due to the addition of the sixth production well and the expected receipt of regulatory approval to produce at higher rates. These gains are expected to be partially offset by natural declines at Hibernia. A major turnaround is not planned for Terra Nova in 2007. White Rose and Hibernia have planned maintenance turnarounds of 16 and 30 days, respectively, in 2007.

Beyond 2007, the East Coast Oil business intends to offset natural declines in the main reservoirs and sustain profitable production by adding production from reservoir extensions and satellite tie-ins. The Hebron project remains a significant resource the Company would like to see developed, subject to the conclusion of a definitive agreement with the provincial government.

[Link to Petro-Canada's Corporate and Strategic Priorities](#)

The East Coast Oil business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2006 and goals for 2007.

	2006 RESULTS	2007 GOALS
<b>Delivering Profitable Growth with a Focus on Operated, Long-Life Assets</b>	<ul style="list-style-type: none"> <li>• ramped up White Rose production, averaging 88,000 b/d gross (24,200 b/d net)</li> <li>• completed drilling the West White Rose 0-28 and North Amethyst K-15 delineation wells at White Rose</li> </ul>	<ul style="list-style-type: none"> <li>• increase reliability at Terra Nova</li> <li>• advance in-field Hibernia growth prospects</li> <li>• delineate West White Rose</li> <li>• advance development plans for South White Rose Extension, North Amethyst and West White Rose prospects</li> </ul>
<b>Driving For First Quartile Operation of Our Assets</b>	<ul style="list-style-type: none"> <li>• completed Terra Nova turnaround for regulatory compliance and to improve reliability</li> <li>• saw operating and overhead costs increase, reflecting turnaround costs at Terra Nova</li> </ul>	<ul style="list-style-type: none"> <li>• conduct a 30-day turnaround scheduled at Hibernia for regulatory compliance</li> <li>• receive regulatory approval to increase annual production from SeaRose FPSO at White Rose</li> <li>• complete 16-day turnaround at White Rose</li> </ul>
<b>Continuing To Work At Being A Responsible Company</b>	<ul style="list-style-type: none"> <li>• saw 28% decrease in TRIF, compared with 2005</li> <li>• accepted responsibility for an improper discharge of oil from Terra Nova in 2004, contributing \$220,000 of the \$290,000 fine to positive environmental projects</li> <li>• improved the produced water system on Terra Nova, resulting in no regulatory compliance exceedances</li> </ul>	<ul style="list-style-type: none"> <li>• further reduce TRIF</li> <li>• apply lessons learned from oily water discharge to prevent future incidents</li> <li>• maintain zero regulatory exceedances</li> </ul>

# OIL SANDS

## BUSINESS SUMMARY AND STRATEGY

Petro-Canada has more than 10 billion barrels of Oil Sands total resource. The Company's major Oil Sands interests include a 12% ownership in the Syncrude joint venture (an oil sands mining operation and upgrading facility), 100% ownership of the MacKay River *in situ* bitumen development (a steam-assisted gravity drainage (SAGD) operation), a 55% ownership in and operatorship of the proposed Fort Hills oil sands mining and upgrading project, and extensive oil sands acreage considered prospective for *in situ* development of bitumen resources.

The Oil Sands strategy for profitable growth includes:

- phased and integrated development of reserves to incorporate knowledge gained
- disciplined capital investment to ensure long-life projects create value
- a staged approach to development of capital-intensive Oil Sands projects to allow rigorous cost management and the opportunity to benefit from evolving technology

The Company has chosen to participate in the full oil sands value chain due to its resource potential and strong position with bitumen upgrading capacity. Petro-Canada not only has processing capacity through Syncrude and Suncor Energy Inc. (starting in 2008), but the Company is also converting the conventional crude oil train at its Edmonton refinery to refine bitumen-based feedstock from northern Alberta, starting in 2008. This conversion, along with the existing synthetic crude train, will result in the refinery running on an exclusive diet of bitumen-based feedstock. This connection between resource and upgrading capacity should provide more economic certainty in a business where volatile light/heavy differentials affect bitumen pricing.

### Oil Sands Financial Results

(millions of Canadian dollars)

	2006	2005	2004
<b>Net earnings</b>	<b>\$ 245</b>	<b>\$ 115</b>	<b>\$ 120</b>
Gain on sale of assets	-	3	-
<b>Operating earnings</b>	<b>\$ 245</b>	<b>\$ 112</b>	<b>\$ 120</b>
Insurance premium surcharges	[3]	[7]	-
Income tax adjustments	44	-	2
Syncrude insurance proceeds	12	-	-
<b>Operating earnings adjusted for unusual items</b>	<b>\$ 192</b>	<b>\$ 119</b>	<b>\$ 118</b>
Cash flow from operating activities before changes in non-cash working capital	\$ 497	\$ 380	\$ 332
Expenditures on property, plant and equipment and exploration	\$ 377	\$ 772	\$ 397
Total assets	\$ 2,885	\$ 2,623	\$ 1,883

### 2006 COMPARED WITH 2005

*Oil Sands contributed \$192 million of operating earnings adjusted for unusual items, up 61% from \$119 million in 2005. Higher realized prices and production were partially offset by increased operating costs.*

Net earnings for Oil Sands were \$245 million in 2006, up from \$115 million in 2005. Net earnings in 2006 included a \$44 million income tax adjustment, \$12 million of Syncrude insurance proceeds related to the 2005 hydrogen plant fire and \$3 million for an insurance premium surcharge. Net earnings in 2005 included a \$3 million gain on the sale of assets and a \$7 million insurance premium surcharge.

Record prices and increased production at Syncrude were highlights of 2006 performance. Syncrude realized price for synthetic crude oil averaged \$72.13/bbl in 2006, up from \$70.41/bbl in 2005. MacKay River realized price for bitumen averaged \$28.93/bbl in 2006, compared with \$18.53/bbl in 2005. Oil Sands production averaged 52,200 b/d net in 2006, compared with 47,000 b/d net in 2005.

### 2006 OPERATING REVIEW AND STRATEGIC INITIATIVES

In 2006, Oil Sands delivered a record \$245 million in operating earnings. Oil Sands strategic progress included selecting Sturgeon County near Edmonton as the location for the Fort Hills upgrader, filing the Sturgeon Upgrader commercial application, updating the Fort Hills mine plan, purchasing additional leases in the Fort Hills and MacKay River areas, completing the Syncrude Stage III expansion and commencing production from the third well pad at MacKay River.

## 2006 Operating Review

### Oil Sands Production and Realized Crude and Bitumen Price

Record prices and increased overall production were the highlights of 2006 performance.



### Oil Sands Operating and Overhead Costs

Syncrude unit operating and overhead costs decreased primarily due to higher production and lower natural gas costs in 2006. MacKay River unit operating and overhead costs increased due to higher costs for goods and services, partially offset by lower natural gas costs in 2006.



	2006	2005	2004
Production net (b/d)			
Syncrude	31,000	25,700	28,600
MacKay River	21,200	21,300	16,600
Total Oil Sands production net	52,200	47,000	45,200
Syncrude realized crude price (\$/bbl)	\$ 72.13	\$ 70.41	\$ 52.40
MacKay River realized bitumen price (\$/bbl)	\$ 28.93	\$ 18.53	\$ 18.37
Syncrude operating and overhead costs (\$/bbl)	\$ 30.00	\$ 31.90	\$ 21.13
MacKay River operating and overhead costs (\$/bbl)	\$ 17.83	\$ 17.06	\$ 21.87

Syncrude's production and unit operating costs were positively affected by the startup of the Stage III expansion in 2006. Following a brief run in May, Syncrude initiated bitumen feed into its new Coker 8-3 on August 30, 2006, enabling the Stage III expansion to come online and begin ramping up. Syncrude's production averaged 258,300 b/d gross (31,000 b/d net) in 2006, compared with 214,200 b/d gross (25,700 b/d net) in 2005. Average unit operating and overhead costs decreased to \$30/bbl in 2006, down from \$31.90/bbl in 2005. Lower unit operating costs were mainly due to higher production and lower natural gas costs, partially offset by Syncrude retention and incentive-based compensation. Syncrude reached royalty payout in the second quarter of 2006 and shifted to a royalty rate of 25% of net operating revenues from 1% of gross revenues. The total royalty paid in 2006 equated to a rate of 10% of gross revenues.

MacKay River's production remained flat and unit operating costs increased slightly in 2006. Production averaged 21,200 b/d in 2006, consistent with an average of 21,300 b/d in 2005, as natural declines were offset by production from the third well pad. MacKay River reliability averaged 92% in 2006, down from 98% in 2005, reflecting a gearbox failure in April. Unit operating and overhead costs increased by 5% in 2006, averaging \$17.83/bbl, compared with \$17.06/bbl in 2005. Higher unit operating costs were due to higher costs for goods and services, partially offset by lower natural gas costs.

### 2006 Strategic Initiatives

At MacKay River, work to tie-in a third well pad was completed and, in January 2006, the new well pad began steaming. Production from the new well pad commenced in the second quarter and continues to ramp up. In the third quarter of 2006, the Company purchased, for \$30 million, 13 additional oil sands leases, comprising a total of 31,232 hectares immediately adjacent to Petro-Canada's existing *in situ* development at MacKay River.

In the fourth quarter of 2006, Petro-Canada announced its intention to divest its interest in the five *in situ* properties of Chard, Stony Mountain, Liege, Thornbury and Ipiatik. The sale process attracted considerable attention; however, the bids received did not meet Petro-Canada's expectation; therefore, the Company will not divest its interests at this time.

Syncrude completed construction of the Stage III expansion project at a total cost of \$8.2 billion (\$1 billion net). At full capacity, the Stage III expansion is expected to add approximately 100,000 b/d gross (12,000 b/d net) and increase the quality of all of Syncrude's sweet synthetic production.

In early 2006, the Fort Hills partners acquired two additional leases adjacent to the existing Fort Hills leases to afford greater mine planning flexibility. The initial phase of mine production is expected to be in the range of 100,000 b/d to 170,000 b/d gross (55,000 b/d to 93,500 b/d net) of bitumen. The partners selected Sturgeon County, 40 kilometres northeast of Edmonton, as the location for the upgrading facility to process bitumen from the Fort Hills mine. The upgrader is expected to produce in the range of 85,000 b/d to 145,000 b/d gross (46,750 b/d to 79,750 b/d net) of synthetic crude oil, with first bitumen production in the 2011 time frame. The Company expects to complete the design basis memorandum (DBM) and preliminary cost estimates for the project by mid-2007.

Oil Sands capital expenditures of \$377 million in 2006 included \$151 million for the Fort Hills development, \$102 million for the Syncrude Stage III expansion and operations, \$86 million for MacKay River and \$38 million for the acquisition of 13 additional leases adjacent to MacKay River, and other *in situ* projects.

## OUTLOOK

### Production expectations in 2007

- Petro-Canada's share of Syncrude production is expected to average 34,000 b/d net
- MacKay River bitumen production is expected to average 24,000 b/d net

### Growth plans

- work to improve reliability at Syncrude
- increase water handling capacity and bitumen production at MacKay River
- advance the Fort Hills oil sands mining and upgrading project
- progress SAGD technology through research and development

### Capital spending plans in 2007

- approximately \$550 million to advance the Fort Hills development and the MacKay River expansion
- approximately \$130 million to enhance existing operations at Syncrude and MacKay River
- approximately \$60 million to replace reserves through ongoing pad development at MacKay River
- approximately \$30 million to advance development of *in situ* oil sands leases

Oil Sands production is expected to increase to 58,000 b/d net in 2007, compared with 52,200 b/d net in 2006. Higher expected production in 2007 is due to a full year of production from the Syncrude Stage III expansion and increased production at MacKay River. The total Syncrude royalty payable in 2007 is expected to equate to a rate of between 10% and 15% of gross revenue, depending on crude oil prices. The total MacKay River royalty payable in 2007 is expected to be 1% of gross revenue.

In 2007, the Company expects to complete the Fort Hills mine, extraction and upgrading DBM, which establishes key design parameters and a more detailed project schedule. Petro-Canada expects to receive a regulatory decision on the filed commercial application for the Sturgeon Upgrader by mid-2008.

The Oil Sands business has a capital program of about \$770 million in 2007. Capital for new growth opportunities of \$550 million includes funding the preliminary engineering and design for the Fort Hills project (forecast to be \$315 million) and the FEED for the MacKay River expansion (forecast to be \$235 million). Spending to enhance existing operations and comply with regulations at Syncrude is budgeted to be \$75 million in 2007. Capital for enhancing existing operations and improving base business profitability at MacKay River is expected to be approximately \$55 million in 2007.

With the initial phase of Fort Hills and the MacKay River expansion, Petro-Canada's production will grow to more than 150,000 b/d net. Beyond that, the Company has the potential to grow the Oil Sands business to approximately 350,000 b/d net over the next decade. Challenges to implementation of the strategy include capital cost pressures, skilled labour shortages, and environmental and stakeholder issues. As an experienced and responsible operator, Petro-Canada is well positioned to meet these challenges.

[Link to Petro-Canada's Corporate and Strategic Priorities](#)

The Oil Sands business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2006 and goals for 2007.

	2006 RESULTS	2007 GOALS
<b>Delivering Profitable Growth with a Focus on Operated, Long-Life Assets</b>	<ul style="list-style-type: none"> <li>• selected Sturgeon County for Fort Hills upgrader location</li> <li>• submitted commercial application for Sturgeon Upgrader</li> <li>• acquired additional oil sands leases adjacent to MacKay River and the existing Fort Hills leases</li> <li>• Syncrude Stage III expansion came on-stream</li> </ul>	<ul style="list-style-type: none"> <li>• complete Fort Hills DBM and initial cost estimate, and initiate FEED</li> <li>• receive regulatory decision on MacKay River expansion project</li> <li>• continue ramp up of Syncrude Stage III expansion</li> <li>• complete MacKay River water handling capacity upgrade and tie-in a fourth well pad so that production can increase in 2008</li> </ul>
<b>Driving For First Quartile Operation of Our Assets</b>	<ul style="list-style-type: none"> <li>• saw Syncrude non-fuel unit operating costs decrease by 5%, compared with 2005</li> <li>• saw MacKay River unit operating costs increase by 5%, compared with 2005, reflecting Alberta business environment</li> <li>• saw Syncrude enter into a Management Services agreement with Imperial Oil Resources for operational, technical and business services</li> <li>• maintained reliability at MacKay River at 92%</li> </ul>	<ul style="list-style-type: none"> <li>• decrease MacKay River non-fuel unit operating costs by 10%, compared with 2006</li> <li>• decrease Syncrude non-fuel unit operating costs by 10%, compared with 2006</li> <li>• sustain MacKay River reliability at greater than 90%</li> </ul>
<b>Continuing To Work At Being A Responsible Company</b>	<ul style="list-style-type: none"> <li>• TRIF decreased by 46%, compared with 2005</li> </ul>	<ul style="list-style-type: none"> <li>• maintain focus on TLM and Zero-Harm</li> <li>• ensure regulators, First Nations and other key stakeholders affected by major projects are properly consulted and engaged</li> </ul>

# INTERNATIONAL

## BUSINESS SUMMARY AND STRATEGY

International production and exploration interests are currently focused in three regions. In Northwest Europe, production comes from the U.K. and the Netherlands sectors of the North Sea, with exploration activities extending into Denmark and Norway. The North Africa/Near East region provides crude oil production from assets in Libya, with exploration activity extending into Syria, Algeria, Tunisia and Morocco. In addition, a natural gas development is underway in Syria. In Northern Latin America, operations are focused in Trinidad and Tobago, and Venezuela.

The International strategy is to access a sizable resource base using a three-fold approach to:

- optimize and leverage existing assets
- seek out new, long-life opportunities
- execute a substantial and balanced exploration program

In 2005, Petro-Canada reached an agreement to sell the Company's mature producing assets in Syria. The sale was closed on January 31, 2006. These assets and associated results are reported as discontinued operations and excluded from continuing operations.

### International Financial Results

(millions of Canadian dollars)

	2006	2005	2004
<b>Net earnings (loss) from continuing operations</b>	<b>\$ (206)</b>	<b>\$ (109)</b>	<b>\$ 116</b>
Unrealized loss on Buzzard derivative contracts	(240)	(562)	(205)
Gain on sale of assets	12	-	8
<b>Operating earnings from continuing operations</b>	<b>\$ 22</b>	<b>\$ 453</b>	<b>\$ 313</b>
Insurance premium surcharges	(8)	(18)	-
Scott insurance proceeds	3	-	-
Income tax adjustments <sup>1</sup>	(242)	29	-
<b>Operating earnings from continuing operations adjusted for unusual items</b>	<b>\$ 269</b>	<b>\$ 442</b>	<b>\$ 313</b>
Cash flow from continuing operating activities before changes in non-cash working capital	\$ 716	\$ 770	\$ 768
Expenditures on property, plant and equipment and exploration from continuing operations	\$ 760	\$ 696	\$ 1,707
Total assets from continuing operations	\$ 6,031	\$ 4,856	\$ 4,969

<sup>1</sup> In 2006, the Company recorded a \$242 million charge for the U.K. supplemental corporate tax rate adjustment.

### 2006 COMPARED WITH 2005

International contributed \$269 million of operating earnings from continuing operations adjusted for unusual items, down 39% from \$442 million in 2005. Lower production, tax adjustments in Northwest Europe, higher exploration, depreciation, depletion and amortization costs, and foreign exchange losses were partially offset by higher realized prices. In 2006, cash flow from continuing operating activities before changes in non-cash working capital remained strong at \$716 million, compared with \$770 million in 2005.

International net loss from continuing operations was \$206 million in 2006, compared with a net loss of \$109 million in 2005. Net loss from continuing operations in 2006 included an unrealized loss on the Buzzard derivative contracts of \$240 million, a \$242 million charge for the U.K. supplemental corporate tax rate adjustment, a \$12 million gain on the sale of non-core assets, an \$8 million insurance premium surcharge and \$3 million in insurance proceeds from the Scott platform fire. Net loss from continuing operations in 2005 included an unrealized loss on the Buzzard derivative contracts of \$562 million, an \$18 million insurance premium surcharge and a \$29 million positive adjustment for income tax rate and other tax adjustments.

International production from continuing operations averaged 103,600 barrels of oil equivalent/day (boe/d) net in 2006, compared with 106,300 boe/d net in 2005. The decrease was primarily due to lower production in Northwest Europe and Northern Latin America. International crude oil and liquids realized prices from continuing operations averaged \$72.69/bbl and natural gas realized prices averaged \$7.64/Mcf in 2006, compared with \$65.93/bbl and \$7.13/Mcf, respectively, in 2005.

Operating and overhead costs from continuing operations averaged \$7.61/boe in 2006, flat compared with \$7.60/boe in 2005.

International capital expenditures from continuing operations in 2006 were \$760 million, with \$588 million directed to Northwest Europe, primarily for North Sea developments, \$120 million invested in the North Africa/Near East region and \$52 million going toward the Northern Latin America region and other capital projects.

## 2006 OPERATING REVIEW AND STRATEGIC INITIATIVES

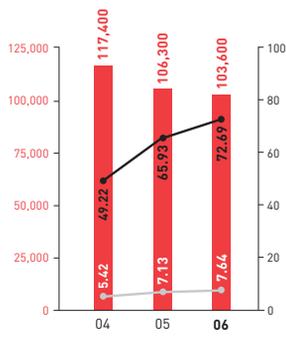
The International business strengthened its production profile by delivering first production from De Ruyter and L5b-C. The business also enhanced its portfolio of assets with the acquisition of long-life natural gas assets in Syria in 2006.

### 2006 Operating Review

#### International Production and Realized Prices

Lower production from continuing operations was primarily due to decreased production in Northwest Europe and Northern Latin America.

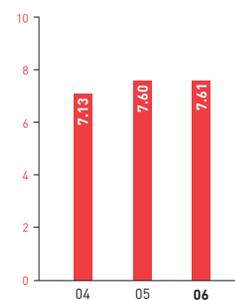
- Production from continuing operations (boe/d)
- Average realized crude oil and NGL price from continuing operations (\$/bbl)
- Average realized natural gas price from continuing operations (\$/Mcf)



#### International Operating and Overhead Costs

Operating and overhead costs were flat in 2006, compared with 2005.

- International operating and overhead costs (\$/bbl)



	2006	2005	2004
Production from continuing operations net (boe/d)			
Northwest Europe	43,700	44,600	54,600
North Africa/Near East	49,400	49,800	50,900
Northern Latin America	10,500	11,900	11,900
<b>Total International production net</b>	<b>103,600</b>	<b>106,300</b>	<b>117,400</b>
Average realized crude oil and NGL price from continuing operations (\$/bbl)	\$ 72.69	\$ 65.93	\$ 49.22
Average realized natural gas price from continuing operations (\$/Mcf)	\$ 7.64	\$ 7.13	\$ 5.42
Operating and overhead costs from continuing operations (\$/boe)	\$ 7.61	\$ 7.60	\$ 7.13

### Northwest Europe

Petro-Canada's Northwest Europe production averaged 43,700 boe/d net in 2006, compared with 44,600 boe/d net in 2005. Natural declines in the U.K. and the Netherlands sectors of the North Sea were partially offset by new production from De Ruyter and L5b-C. Northwest Europe crude oil and liquids realized prices averaged \$72.67/bbl and natural gas averaged \$8.91/Mcf in 2006, compared with \$66.13/bbl and \$7.35/Mcf, respectively, in 2005.

During 2006, Petro-Canada continued to leverage its existing infrastructure through concentric development near core areas and through new discoveries. Although the basin is mature, the Company continues to secure new developments, including the Buzzard, Pict and Saxon fields in the U.K. sector of the North Sea, and the De Ruyter and L5b-C fields in the Netherlands sector of the North Sea.

In the U.K. sector of the North Sea, the Buzzard development, in which the Company has a 29.9% interest, achieved first oil in January 2007. The field is expected to ramp up to peak production in mid-2007. In 2006, a rig was secured to complete a 12-month program of development, infill and exploration drilling, which began in early 2007. This program includes completing the Saxon project, a Pict look-alike 100% owned and operated by Petro-Canada. The Saxon development will be tied back to the Triton area infrastructure and is expected to be on-stream at the end of 2007, with peak production of approximately 7,000 boe/d gross. Following the discovery in 2005 on the Petro-Canada operated 13/27a Block (90% working interest), the Company farmed into adjacent Blocks 13/26a and 13/26b in September 2006,

obtaining a 27.5% non-operated working interest. Appraisal drilling to test the extent of the 13/27a discovery is planned by the operator for the second half of 2007. In late 2006, the Golden Eagle discovery was made on the non-operated Block 20/1 North located near the Buzzard field. The Company has a 25% working interest in this licence and work is ongoing to assess the possible development of the discovery. In early 2007, Petro-Canada was awarded Block 13/24d near Buzzard in the U.K. 24th licensing round. The Company is operator with a 90% working interest.

In the Netherlands sector of the North Sea, the De Ruyter and L5b-C developments achieved first production in 2006. De Ruyter, a Petro-Canada operated oil development, came on-stream in late September and delivered 5,500 boe/d gross (2,970 boe/d net) in 2006. The Company has a 54.07% working interest in De Ruyter, which is expected to add around 10,000 boe/d net to Petro-Canada in 2007. L5b-C, a non-operated asset in which the Company holds a 30% working interest, achieved first gas in mid-November 2006 and is expected to add 3,000 boe/d net to Petro-Canada in 2007. Two offshore exploration wells near the De Ruyter field are planned during 2007 and the Company expects to participate in one other non-operated exploration well in 2007.

In 2006, Petro-Canada opened an office in Stavanger, Norway, following the award of five production licences in the Norwegian sector of the North Sea in the 2005 Awards in Predefined Areas (APA). In 2007, the Company was awarded seven additional production licences in the 2006 APA round. Petro-Canada is operator of four of the 12 licences in Norway.

Technical and commercial studies relating to development scenarios were undertaken on the Hejre field in Denmark in 2006. A non-operated licence (20% working interest) was acquired adjacent to the Hejre field as protection acreage for the discovery in 2006. The Stork and Robin prospects were drilled and completed as dry holes. This resulted in the Company's decision to relinquish the Robin licence in January 2007. The exploration period on the Svane discovery was extended by two years in 2006 to complete technical and economic re-evaluation.

#### *North Africa/Near East*

In 2006, Petro-Canada's production from continuing operations in this region averaged 49,400 boe/d net, relatively unchanged from 49,800 boe/d net in 2005. North Africa/Near East crude oil and liquids realized prices from continuing operations averaged \$72.70/bbl in 2006, compared with \$65.79/bbl in 2005.

In the North Africa/Near East region, Petro-Canada continues to assess the significant future resource potential, using the Company's experience and assets in the area as leverage for long-term growth.

In Syria, the Company completed the sale of its mature producing assets in early 2006. In November, Petro-Canada acquired operatorship and a 90% interest in a Production-Sharing Contract (PSC) in the Ash Shaer and Cherrife natural gas fields for \$54 million. Under the agreement, Petro-Canada expects to develop and produce an estimated 80 MMcf/d of natural gas, with first gas anticipated in 2010. In addition, preparations for drilling on Block II progressed, with two exploration wells expected to be drilled in 2007.

In 2006, nine development wells were drilled in the producing fields in Libya, of which seven were completed. A further three exploration wells were drilled, with one new discovery on existing concessions. In 2007, Petro-Canada expects to participate in three exploration and appraisal wells with Veba Oil Operations. The Company was awarded an exploration licence in the Libyan third round exploration and production-sharing agreement (EPSA) IV auction. The onshore licence is located in the Sirte Basin and Petro-Canada is the operator with a 50% working interest.

Petro-Canada spudded an exploration well on the Zotti Block in Algeria in late 2006. In Tunisia, the Company closed its Tunis office and relinquished its 72.5% interest in the Melitta Block after completing its work commitment. The Company intends to focus on exploration on the offshore, non-operated Cap Serrat and Bechateaur permits in 2007 (33% working interest). In Morocco, Petro-Canada extended its reconnaissance licence by another 12 months on the Bas Draa Block. A gravity magnetic survey will take place on the block in the first half of 2007.

## Northern Latin America

In 2006, Petro-Canada's share of Trinidad and Tobago production averaged 63 MMcf/d net, down from 72 MMcf/d net in 2005. This was due to a reduction in overall processing capacity at the Atlantic LNG plant, following maintenance on Trains 2 and 3, and delays in commissioning Train 4. Northern Latin America realized prices for natural gas averaged \$5.13/Mcf in 2006, compared with \$6.62/Mcf in 2005.

In Trinidad and Tobago, 3D seismic surveys on offshore Blocks 1a, 1b and 22, covering a total area of 4,433 square kilometres, were completed in 2006. Long lead materials were secured and drilling rigs contracted to complete a drilling program of up to eight exploration wells starting in 2007. The evaluation of seismic data and work to obtain environmental approvals for the drilling program progressed in 2006. The Company continues to develop its 17.3% working interest in the North Coast Marine Area (NCMA-1) asset. Phase 3a and 3b subsea tie-backs to the Hibiscus platform were completed and first natural gas was achieved in late 2006. Phase 3c was approved and will involve the development of the Poinsettia field, with a platform and pipeline tie-back to the Hibiscus platform. Production is expected to come on-stream by early 2009.

In Venezuela, the La Ceiba field development plan is awaiting approval by the Venezuelan authorities. Petro-Canada has a 50% non-operated interest in the field.

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## OUTLOOK

### Production expectations in 2007

- North Africa/Near East oil and gas production to average 49,000 boe/d net
- Northwest Europe oil and gas production to average 85,000 boe/d net
- Northern Latin America natural gas production to average 66 MMcf/d net

### Growth plans

- advance Saxon development for 2007 startup
- execute the exploration program in Northern Latin America, Northwest Europe and North Africa/Near East

- advance natural gas development in Syria
- continue to pursue new business opportunities in LNG

### Capital spending plans in 2007

- approximately \$340 million for reserves replacement spending in core areas
- approximately \$275 million primarily for new growth projects in Syria and the North Sea
- approximately \$250 million for exploration and new ventures

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International production from continuing operations is expected to be about 145,000 boe/d net in 2007, compared with 103,600 boe/d net in 2006. The anticipated 40% increase in production in 2007 reflects contributions from new development projects, such as De Ruyter, Buzzard, L5b-C and Saxon. These projects are expected to more than offset the 15% to 20% natural declines in Northwest Europe.

The Company continues to advance discussions on importing gas from Russia to North America through a joint LNG project with OAO «Gazprom» (Gazprom). The liquefaction plant proposed in the St. Petersburg region is expected to export 3.5 million tonnes to 5 million tonnes per annum (or 500 MMcf/d to 700 MMcf/d) of gas supplied from the Russian grid. An agreement was signed with Gazprom in March 2006 to proceed with the initial engineering design of the liquefaction plant. The preliminary engineering studies will provide cost and schedule estimates from which the Company may proceed into detailed design and engineering for the liquefaction plant.

*Link to Petro-Canada's Corporate and Strategic Priorities*

The International business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2006 and goals for 2007.

	2006 RESULTS	2007 GOALS
<b>Delivering Profitable Growth with a Focus on Operated, Long-Life Assets</b>	<ul style="list-style-type: none"> <li>• achieved first production at De Ruyter and L5b-C</li> <li>• closed sale of mature Syrian producing assets</li> <li>• acquired 90% interest and became operator of the Ash Shaer and Cherrife gas project</li> <li>• secured drilling rigs for 2007 and 2008 exploration programs</li> <li>• awarded Sirte licence in Libyan third round EPSA IV auction</li> </ul>	<ul style="list-style-type: none"> <li>• ramp up Buzzard and L5b-C to full production</li> <li>• achieve first production at Saxon in the U.K. sector of the North Sea by year end</li> <li>• participate in up to a 17-well exploration drilling program, (depending on rig arrival dates) with balanced risk profile over the next 18 months</li> <li>• commence field appraisal and project design activities on Ash Shaer and Cherrife development</li> <li>• establish a Libyan exploration program on the newly acquired Sirte exploration block</li> <li>• actively pursue LNG supply opportunities</li> </ul>
<b>Driving For First Quartile Operation of Our Assets</b>	<ul style="list-style-type: none"> <li>• achieved more than 95% uptime on Hanze platform</li> <li>• achieved full production capacity at De Ruyter platform ahead of schedule</li> <li>• seconded specialists to support Libyan operations</li> <li>• improved Scott platform reliability and uptime by 33%, compared with 2005</li> </ul>	<ul style="list-style-type: none"> <li>• maintain excellent reliability at De Ruyter platform</li> <li>• optimize production capacity on Triton area assets by implementing recommendations from de-bottlenecking study</li> </ul>
<b>Continuing To Work At Being A Responsible Company</b>	<ul style="list-style-type: none"> <li>• had nine recordable injuries in 2006, compared with 14 in 2005, but TRIF rose to 0.8 in 2006, compared with 0.62 in 2005, reflecting fewer person hours worked</li> <li>• achieved five years of continuous operations on the Hanze platform without a lost-time incident</li> <li>• provided safety training and equipment to fishermen in Trinidad and Tobago as part of community liaison activities during seismic operations</li> </ul>	<ul style="list-style-type: none"> <li>• maintain focus on TRIF and increase leadership visibility of Zero-Harm effort</li> <li>• reduce oil in produced water at Triton</li> <li>• collaborate with local stakeholders in Trinidad and Tobago to minimize impact of offshore drilling</li> </ul>

*Discontinued Operations*

On January 31, 2006, Petro-Canada completed the sale of the Company's producing assets in Syria to a joint venture of companies owned by India's Oil and Natural Gas Corporation Limited and the China National Petroleum Corporation for net proceeds of \$640 million. The sale resulted in a gain on disposal of \$134 million recorded in the first quarter of 2006. This sale aligned with Petro-Canada's strategy to increase the proportion of long-life and operated assets within its portfolio. Petro-Canada's activities in Syria remain part of the North Africa/Near East producing region, with an active exploration program in Block II and the addition of the Ash Shaer and Cherrife natural gas projects in Syria during 2006.

Producing assets in Syria are presented as discontinued operations in the Consolidated Financial Statements. Petro-Canada's net earnings from discontinued operations in 2006 were \$152 million and included a gain on disposal of \$134 million. Summary information is presented on the following page. Additional information concerning Petro-Canada's discontinued operations can be found in Note 4 to the Consolidated Financial Statements.

## Discontinued Financial Results

(millions of Canadian dollars, unless otherwise noted)

	2006	2005	2004
<b>Net earnings from discontinued operations</b>	<b>\$ 152</b>	<b>\$ 98</b>	<b>\$ 59</b>
Gain on sale of assets	134	-	-
<b>Operating earnings from discontinued operations</b>	<b>\$ 18</b>	<b>\$ 98</b>	<b>\$ 59</b>
Insurance premium surcharges	-	[2]	-
<b>Operating earnings from discontinued operations adjusted for unusual items</b>	<b>\$ 18</b>	<b>\$ 100</b>	<b>\$ 59</b>
Cash flow from operating activities before changes in non-cash working capital	\$ 17	\$ 245	\$ 204
Expenditures on property, plant and equipment and exploration	\$ 1	\$ 46	\$ 62
Total assets	\$ -	\$ 648	\$ 985
Total volumes <i>(boe/d)</i>			
- net before royalties	5,500	70,100	79,200
- net after royalties	1,400	21,000	24,200
Average realized crude oil and NGL price <i>(\$/bbl)</i>	\$ 71.84	\$ 61.82	\$ 46.70
Average realized natural gas price <i>(\$/Mcf)</i>	\$ 7.94	\$ 6.43	\$ 4.81

## UPSTREAM PRODUCTION

### 2006 COMPARED WITH 2005

In 2006, Petro-Canada's production from continuing operations of crude oil, NGL and natural gas averaged 345,400 boe/d net, down from 354,600 boe/d net in 2005.

### 2006 Average Daily Production Volumes Net

	North American		East		Total
	Natural Gas	Coast Oil	Oil Sands	International	
<b>Crude oil, NGL and bitumen <i>(b/d)</i></b>					
- net before royalties	14,200	72,700	21,200	82,600	190,700
- net after royalties	10,800	68,500	20,800	77,900	178,000
<b>Synthetic crude oil <i>(b/d)</i></b>					
- net before royalties	-	-	31,000	-	31,000
- net after royalties	-	-	28,000	-	28,000
<b>Natural gas <i>(MMcf/d)</i></b>					
- net before royalties	616	-	-	126	742
- net after royalties	489	-	-	95	584
<b>Continuing operations <i>(boe/d)</i></b>					
- net before royalties	116,900	72,700	52,200	103,600	345,400
- net after royalties	92,300	68,500	48,800	93,700	303,300
<b>Discontinued operations <i>(boe/d)</i></b>					
- net before royalties	-	-	-	5,500	5,500
- net after royalties	-	-	-	1,400	1,400
<b>Total volumes <i>(boe/d)</i></b>					
- net before royalties	116,900	72,700	52,200	109,100	350,900
- net after royalties	92,300	68,500	48,800	95,100	304,700

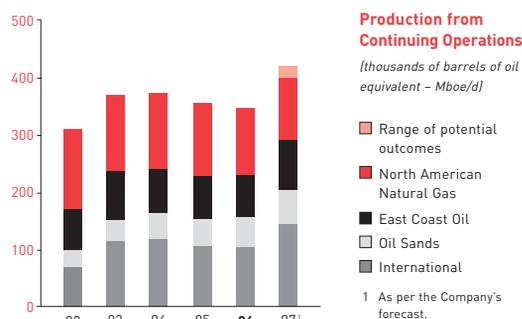
**2005 Average Daily  
Production Volumes Net**

	North American Natural Gas	East Coast Oil	Oil Sands	International	Total
<b>Crude oil, NGL and bitumen</b> (b/d)					
- net before royalties	14,700	75,300	21,300	83,500	194,800
- net after royalties	11,200	69,600	21,100	77,700	179,600
<b>Synthetic crude oil</b> (b/d)					
- net before royalties	-	-	25,700	-	25,700
- net after royalties	-	-	25,400	-	25,400
<b>Natural gas</b> (MMcf/d)					
- net before royalties	668	-	-	138	806
- net after royalties	512	-	-	95	607
<b>Continuing operations</b> (boe/d)					
- net before royalties	126,000	75,300	47,000	106,300	354,600
- net after royalties	96,500	69,600	46,500	93,500	306,100
<b>Discontinued operations</b> (boe/d)					
- net before royalties	-	-	-	70,100	70,100
- net after royalties	-	-	-	21,000	21,000
<b>Total volumes</b> (boe/d)					
- net before royalties	126,000	75,300	47,000	176,400	424,700
- net after royalties	96,500	69,600	46,500	114,500	327,100

**2007 Production Outlook**

Upstream production is expected to increase in 2007 with additional volumes from Buzzard, Terra Nova, the Syncrude expansion, De Ruyter and L5b-C. Offsetting these increases are lower production from North American Natural Gas and natural declines in the North Sea. Production is expected to average in the range of 390,000 boe/d net to 420,000 boe/d net in 2007, up from 2006.

Factors that may impact production during 2007 include reservoir performance, drilling results, facility reliability (particularly at Terra Nova), ramp up of production at Buzzard, De Ruyter and L5b-C, regulatory approval of increased facility throughput at White Rose and the successful execution of planned turnarounds.



**Consolidated Production from Continuing Operations Net**

(thousands of boe/d)

2007 Outlook (+/-)

<b>North American Natural Gas</b>	
Natural gas	97
Liquids	13
<b>East Coast Oil</b>	87
<b>Oil Sands</b>	
Syncrude	34
MacKay River	24
<b>International</b>	
North Africa/Near East <sup>1</sup>	49
Northwest Europe	85
Northern Latin America	11
<b>Total continuing operations</b>	<b>390 - 420</b>

<sup>1</sup> North Africa/Near East excludes production from the mature Syrian producing assets sold in 2006.

# Reserves Summary

The Company's reserves data and reserves quantities are determined by Petro-Canada's staff of qualified reserves evaluators using corporate-wide policies, procedures and practices. These reserves policies, procedures and practices conform with the requirements in Canada, as well as with the U.S. SEC and the Association of Professional Engineers, Geologists and Geophysicists of Alberta's Standard of Practice for the Evaluation of Oil and Gas Reserves for Public Disclosure. Petro-Canada also employs independent third parties to evaluate, audit and/or review its reserves processes and estimates. In 2006, 53% of North American (or 34% if Syncrude oil sands mining is included) and 29% of International proved oil and gas reserves were assessed by independent reserves evaluators. The independent reserves evaluators concluded that the Company's year-end reserves estimates were reasonable.

<b>December 31, 2006</b> <b>Consolidated Reserves<sup>1</sup></b> <i>(working interest before royalties)</i>	<b>Proved Liquids</b> <i>(MMbbls)</i>	<b>Proved Gas</b> <i>(Billion cubic feet – Bcf)</i>	<b>Proved Reserves Additions Liquids<sup>3</sup></b> <i>(MMbbls)</i>	<b>Proved Reserves Additions Gas<sup>3</sup></b> <i>(Bcf)</i>	<b>Proved<sup>2</sup></b> <i>(Million bbls of oil equivalent – MMboe)</i>	<b>Proved Reserves Additions<sup>3</sup></b> <i>(MMboe)</i>
North American Natural Gas	47	1,645	3	44	321	10
East Coast Oil	123	–	18	–	123	18
Oil Sands <sup>4</sup>	502	–	179	–	502	179
International <sup>5</sup>	278	300	(35)	(24)	328	(39)
<b>Total</b>	<b>950</b>	<b>1,945</b>	<b>165</b>	<b>20</b>	<b>1,274</b>	<b>168</b>
Production net	81	270				126
Proved replacement ratio <sup>6,7</sup>						134%

1 A comparative table for 2006 versus 2005 is shown on page 78.

2 At year-end 2006, 63% of proved reserves were classified as proved developed reserves. Of the total undeveloped reserves, 95% are associated with large projects currently producing or under active development, including Buzzard, Syncrude, MacKay River, Hibernia, Terra Nova, White Rose, and Trinidad and Tobago natural gas.

3 Proved reserves additions are the sum of revisions of previous estimates, net purchases/sales, and discoveries, extensions and improved recovery in 2006. Further detail on these categories is provided in the reserves table on page 78.

4 Oil Sands proved reserves include reserves from Syncrude and MacKay River. Syncrude is an oil sands mining operation. Oil sands mining is not an oil and gas activity as defined by the SEC. The mining proved reserves are estimated in accordance with the SEC Industry Guide 7.

5 The year-end reserves reflect Petro-Canada's sale of its mature Syrian producing assets on January 31, 2006. The 2005 year-end Syrian proved reserves were 49 MMboe. The 2006 production presented does not include any production from the Syrian producing assets.

6 This ratio is the year-over-year net change in proved reserves (before deducting production), divided by annual production over the same time period. Proved reserves replacement ratio is a general indicator of the Company's reserves growth. It is only one of a number of metrics that can be used to analyse a company's upstream business.

7 Reserves replacement ratio and reserves life index are non-standardized measures and may not be comparable to similar measures of other companies. They are illustrative only.

## December 31, 2006

Five-year proved plus probable replacement ratio	175%
Proved plus probable reserves life index <sup>8,9</sup>	17.3

8 This index is proved plus probable reserves at year-end 2006, divided by annual production.

Petro-Canada's objective is to replace reserves over time through exploration, development and acquisition. The Company believes that, due to the specific nature of its upstream portfolio and attributes of its probable reserves, the combination of proved plus probable reserves provides the best perspective of Petro-Canada's reserves. Petro-Canada's proved plus probable reserves replacement on a consolidated basis was 175%<sup>9</sup> over the last five years. The proved plus probable reserves life index was 17.3<sup>9</sup> years at year-end 2006, compared with 14.7 years at year-end 2005.

In 2006, the Company replaced 134%<sup>9</sup> of production on a proved basis. Proved reserves additions totalled 168 MMboe<sup>9</sup>, compared with 2006 production of 126 MMboe net<sup>9</sup>. As a result, total proved reserves increased from 1,232 MMboe<sup>9</sup> at year-end 2005 to 1,274 MMboe<sup>9</sup> at year-end 2006.

The North American Natural Gas business added 10 MMboe of proved reserves additions in 2006. Lower than expected reserves additions reflected technical revisions related to reservoir performance of some Western Canada pools and application of year-end natural gas prices as stipulated by the SEC. These factors were partially offset by reserves additions from exploration and development activity.

9 Reserves replacement ratio and reserves life index are non-standardized measures and may not be comparable to similar measures of other companies. They are illustrative only. Company total proved reserves include oil and gas activity proved reserves plus oil sands mining proved reserves (oil sands mining reserves – 345 MMbbls and 2006 annual production – 11 MMbbls).

In East Coast Oil, 18 MMbbls were added to proved reserves during 2006. This was due to ongoing development well drilling at White Rose, Terra Nova and Hibernia.

In 2006, 179 MMbbls of proved reserves were added in Oil Sands.<sup>1</sup> At MacKay River, year-end bitumen prices resulted in positive economics, permitting the booking of proved reserves in compliance with SEC guidance. Development and delineation drilling, combined with an increased proved recovery factor, resulted in the addition of 165 MMbbls of proved reserves at MacKay River. At Syncrude, 14 MMbbls were added to proved reserves, reflecting extraction efficiencies.

International proved reserves declined by 39 MMboe in 2006 due to the sale of the mature Syrian producing assets. Partially offsetting this decline was the addition of proved reserves at Buzzard.

Further detail on Petro-Canada's reserves is provided in the reserves table at the end of this report (see page 78).

## Downstream



Montreal refinery



Lubricants plant in Mississauga



One of more than 1,300 retail stations in Canada



One of 219 PETRO-PASS locations in Canada

### BUSINESS SUMMARY AND STRATEGY

Petro-Canada is the second largest Downstream business and the “brand of choice” in Canada. In 2006, Petro-Canada accounted for approximately 13% of the total refining capacity in Canada and about 16% of total petroleum products sold in Canada.

Downstream operations include two refineries – one in Edmonton and one in Montreal – with a total daily rated capacity of 40,500 cubic metres/day ( $m^3/d$ ) (255,000 b/d), a lubricants plant – the largest producer of lubricant base stocks in Canada, a network of more than 1,300 retail service stations, Canada's largest commercial road transport network of 219 locations and a robust bulk fuel sales channel.

The strategy in the Downstream business is to increase the profitability of the base business through effective capital investment and disciplined management of controllable factors. In 2007, planned Downstream capital investment will shift to growth projects as regulatory projects to produce cleaner burning fuels were completed in 2006. The Downstream business' goal is to deliver superior returns and growth, including a 12% return on capital employed (ROCE) based on a mid-cycle business environment. Key features of the strategy include:

- achieving and maintaining first quartile operating performance in all areas
- advancing Petro-Canada as the “brand of choice” for Canadian gasoline consumers
- increasing sales of high margin specialty lubricants

The trend toward increased heavy crude production globally has resulted in increased need for refining capacity that can process this feedstock. As a result, Petro-Canada is converting the conventional crude oil train at its Edmonton refinery to refine bitumen-based feedstock from northern Alberta, with completion expected by 2008. The Edmonton refinery conversion project is expected to add earnings and cash flow starting in 2008. As well, the Company is considering construction of a 25,000 b/d coker at its Montreal refinery. An investment decision on a new coker at the Montreal refinery is expected to be made in 2007. If the coker project is approved, completion is targeted for late 2009 and is expected to add earnings and cash flow in 2010.

<sup>1</sup> Oil Sands proved reserves include reserves from Syncrude and MacKay River. Syncrude is an oil sands mining operation. Oil sands mining is not an oil and gas activity as defined by the SEC. The mining proved reserves are estimated in accordance with the SEC Industry Guide 7.

## Downstream Financial Results

(millions of Canadian dollars)

	2006	2005	2004
<b>Net earnings</b>	<b>\$ 473</b>	<b>\$ 415</b>	<b>\$ 314</b>
Gain on sale of assets	10	17	4
<b>Operating earnings</b>	<b>\$ 463</b>	<b>\$ 398</b>	<b>\$ 310</b>
Insurance premium surcharges	(8)	(23)	–
Income tax adjustments	41	(2)	2
Oakville closure costs	–	2	(46)
<b>Operating earnings adjusted for unusual items</b>	<b>\$ 430</b>	<b>\$ 421</b>	<b>\$ 354</b>
Cash flow from operating activities before changes in non-cash working capital	\$ 790	\$ 607	\$ 556
Expenditures on property, plant and equipment	\$ 1,229	\$ 1,053	\$ 839
Total assets	\$ 6,649	\$ 5,609	\$ 4,462

## 2006 COMPARED WITH 2005

Downstream contributed \$430 million of operating earnings adjusted for unusual items, up 2% from \$421 million in 2005. Strong reliability at the Edmonton and Montreal refineries allowed Petro-Canada to maximize the benefits of favourable refining margins and a wider light/heavy crude price differential. These benefits were partially offset by the impact of higher operating costs associated with the planned refinery turnarounds in the second quarter, higher energy prices and one-time expenses incurred due to a fire at the Mississauga lubricants plant.

Net earnings from Downstream were a record \$473 million in 2006, up from \$415 million in 2005. Net earnings in 2006 included a \$41 million income tax adjustment, a \$10 million gain on the sale of assets and an \$8 million insurance premium surcharge. Net earnings in 2005 included a \$17 million gain on the sale of assets and a \$23 million insurance premium surcharge.

Refining and Supply contributed 2006 operating earnings adjusted for unusual items of \$352 million, compared with \$366 million in 2005. Lower 2006 operating earnings adjusted for unusual items reflected major planned turnarounds at the Edmonton and Montreal refineries and a fire at the Mississauga lubricants plant. These factors were partially offset by favourable realized refining margins.

Total sales of refined products decreased by less than 1%, compared with 2005. The reduced volumes were mainly due to lower furnace fuel oil sales as a result of warmer winter weather in Eastern Canada.

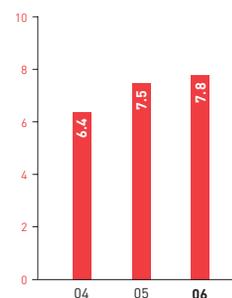
In 2006, marketing contributed operating earnings adjusted for unusual items of \$78 million, compared with \$55 million in 2005. Improved margins were partially offset by increased costs related to higher fuel prices.

Total Downstream operating, marketing, and general and administrative unit costs of 7.8 cents/litre in 2006 were up from 7.5 cents/litre in 2005. The increase mainly reflected increased shutdown costs, operating costs driven by higher energy prices and transportation costs, and one-time expenses incurred due to a fire at the Mississauga lubricants plant.

### Downstream Operating, Marketing and General Costs

Per litre costs reflected higher shutdown and operating costs, as well as one-time expenses.

■ Downstream operating, marketing and general costs (cents/litre)



## 2006 OPERATING REVIEW AND STRATEGIC INITIATIVES

In 2006, the Downstream delivered record operating earnings for the third year in a row of \$463 million due to a continued strong business environment and reliable operations at the Company's two refineries. With the major regulatory projects complete in 2006, Petro-Canada is well positioned with the supply capability to optimize profitability within a range of future business environment scenarios.

### Refining and Supply

In 2006, the business processed an average of 37,800 m<sup>3</sup>/d of crude oil, down from 40,900 m<sup>3</sup>/d in 2005. The overall utilization rate at Petro-Canada's two refineries averaged 93% in 2006, down from 96% in 2005. The decline reflected planned major turnarounds at the Edmonton and Montreal refineries for maintenance and completion of the ultra-low sulphur diesel projects.

Overall plant reliability is a critical component of success in the refining business. For the second year in a row, strong operational performance at both refineries resulted in an overall reliability index of 95.

Work at the Montreal and Edmonton refineries to bring new diesel desulphurization units on-stream was completed on schedule in the second quarter of 2006.

Looking forward, Petro-Canada is well positioned to take advantage of the trend toward increased production of cheaper, heavier crudes. At the Edmonton refinery in 2006, the Company completed detailed engineering and started construction of new crude and vacuum units, and expanded coker and sulphur capacity. This was part of the refinery conversion project to upgrade and refine bitumen-based feedstock. The Edmonton refinery conversion project is estimated to cost \$2 billion and come on-stream in 2008. At its Montreal refinery, the Company furthered work to evaluate the feasibility of adding a 25,000 b/d coker to the refinery. An investment decision on a new coker at the Montreal refinery is expected to be made in 2007.

### Marketing

Total Downstream sales decreased to an average 52,500 m<sup>3</sup>/d in 2006, compared with 52,800 m<sup>3</sup>/d in 2005. Lower volumes were mainly due to a decline in furnace fuel oil sales as a result of warmer weather.

In the retail business, Petro-Canada completed most of its re-imaging program, contributing to industry-leading throughputs. Within the Company's network, annual gasoline sales from re-imaged sites averaged in excess of 7 million litres per site. The Company has extended the re-imaging program to independent retailers and, to date, nearly 62% of these retailers have chosen to participate.

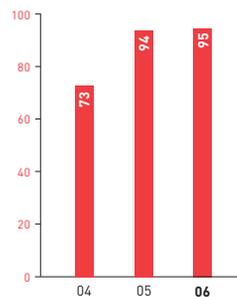
Petro-Canada continued to leverage its position as "Canada's Gas Station." In 2006, the Company continued to focus on expanding its non-petroleum revenue base, as evidenced by the 8% year-over-year sales growth of its convenience store business and 5% increase in same-store sales, compared with 2005.

In 2006, the PETRO-PASS network, which includes 219 truck stop facilities, continued to be the leading national marketer of fuel in the commercial road transport segment in Canada. The distribution network was upgraded during the year.

#### Refinery Reliability Index

The refinery reliability index score improved in 2006, reflecting improved maintenance procedures.

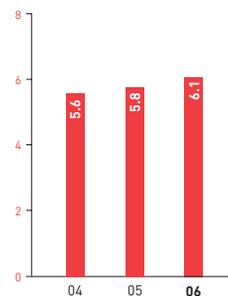
■ Refinery reliability index



#### Gasoline Throughput per Retail Site

Total Downstream sales per retail site continued to grow in 2006.

■ Gasoline throughput per retail site (millions of litres)  
- Excludes Petro-Canada branded sites operated by independent dealers.



## Lubricants

Overall sales of lubricants totalled 722 million litres in 2006, a decrease of 7% compared with sales volumes of 779 million litres in 2005. The decrease in sales volumes was primarily due to the impact of a fire at the lubricants facility early in 2006.

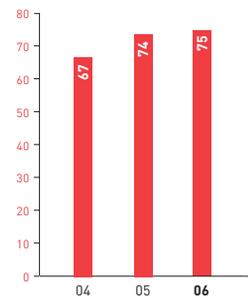
An investigation of the fire at the Mississauga lubricants plant indicated that the event occurred during a routine maintenance procedure in a fractionation section of the plant. Following the fire, the lubricants plant temporarily operated at 50% capacity. Repairs were completed and production on the unit was restored to pre-incident levels in March 2006. In June, the 25% expansion of the lubricants plant came on-stream. Sales in high margin product segments represented 75% of total sales, a 1% increase compared with 2005. Over the past five years, sales of high margin products have grown by approximately 26%.

Lubricants is positioned for profitable future growth as tougher performance and environmental standards increase global demand for higher quality base oils and finished products like those produced at the Mississauga lubricants plant.

### Lubricants High Margin Sales

Lubricants high margin sales mix increased by 1% in 2006.

■ % of high margin sales to total volume  
- 2005 restated



## OUTLOOK

### Growth plans

- drive for first quartile refinery safety and reliability
- advance Edmonton refinery conversion project to process bitumen-based feedstock by 2008
- make investment decision for a coker at the Montreal refinery
- increase service station network effectiveness, with a focus on increasing non-petroleum revenue
- build wholesale volumes primarily through our commercial road transport and bulk fuels sales channels
- increase sales of high quality, higher margin lubricants

### Capital spending plans in 2007

- approximately \$1,075 million focused on new growth projects, such as the Edmonton refinery conversion and the possible Montreal coker
- approximately \$125 million to enhance existing operations
- approximately \$120 million to improve profitability in the base business
- approximately \$70 million for regulatory compliance projects

Downstream capital spending shifts from regulatory requirements to growth in 2007, in particular with the conversion of the Edmonton refinery and an investment decision on a possible Montreal coker.

The Downstream business will have a capital program of approximately \$1,390 million in 2007. The majority of capital spending is forecasted for new growth project funding of \$1,075 million. This capital will be directed toward advancing the Edmonton refinery conversion project and completing the FEED on the 25,000 b/d Montreal coker in preparation for the 2007 investment decision.

Approximately \$125 million is forecasted to be directed to the enhancement of existing operations. This includes reliability and safety improvements at Downstream facilities, as well as site enhancement within the wholesale and retail networks. A further \$120 million is planned to be invested to improve the profitability of the Downstream's base business. This includes a number of high return refining projects and continued development of the retail and wholesale network.

Approximately \$70 million is expected to be invested in regulatory compliance, down considerably from the \$290 million invested in 2006. The majority of the 2006 regulatory compliance capital was required to produce cleaner burning diesel fuel.

Based on the current mid-cycle business environment, the Downstream business delivered a mid-cycle ROCE of more than 10% in 2006. Over time, it is anticipated that improvement in the base business and the refinery conversion projects will help drive the mid-cycle ROCE to the target of 12%.

The Downstream business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2006 and goals for 2007.

	2006 RESULTS	2007 GOALS
<b>Delivering Profitable Growth with a Focus on Operated, Long-Life Assets</b>	<ul style="list-style-type: none"> <li>completed lubricant plant 25% expansion</li> <li>completed detailed engineering and 18% of the Edmonton refinery conversion project</li> </ul>	<ul style="list-style-type: none"> <li>continue the Edmonton refinery conversion project to enable the planned startup in 2008</li> <li>complete Montreal coker feasibility study for investment decision in 2007</li> <li>continue to invest in smaller scale refinery yield and reliability improvement projects</li> <li>continue to integrate the Montreal refinery and the ParaChem Chemicals L.P. plant</li> </ul>
<b>Driving For First Quartile Operation of Our Assets</b>	<ul style="list-style-type: none"> <li>achieved a combined reliability index of 95 at the Company's two refineries, above 90 for a second year in a row</li> <li>completed multi-year project to produce cleaner burning fuels at refineries</li> <li>maintained leading share of major retail urban market</li> <li>grew convenience store sales by 8% and same-store sales by 5%, compared with 2005</li> <li>achieved 75% high margin lubricant sales volume mix</li> </ul>	<ul style="list-style-type: none"> <li>continue to focus on safety and refinery reliability</li> <li>increase retail non-petroleum revenue</li> <li>grow high margin lubricants sales volume</li> </ul>
<b>Continuing To Work At Being A Responsible Company</b>	<ul style="list-style-type: none"> <li>reduced TRIF by 3%, compared with 2005</li> <li>reduced regulatory compliance exceedances by 17%, compared with 2005</li> </ul>	<ul style="list-style-type: none"> <li>maintain focus on TRIF and regulatory compliance exceedances</li> <li>meet provincial ethanol regulations</li> <li>continue focus on community relations, including establishment of Community Liaison Committee in Montreal</li> <li>continue to look for partnerships with Aboriginal communities on retail opportunities</li> </ul>

## Shared Services

Shared Services includes investment income, interest expense, foreign currency translation and general corporate revenue and expenses.

### Shared Services Financial Results

(millions of Canadian dollars)

	2006	2005	2004
<b>Net loss</b>	<b>\$ (263)</b>	<b>\$ (177)</b>	<b>\$ (63)</b>
Loss on sale of assets	-	-	(1)
Foreign currency translation gain	1	73	63
<b>Operating loss</b>	<b>\$ (264)</b>	<b>\$ (250)</b>	<b>\$ (125)</b>
Stock-based compensation	(31)	(66)	(11)
Income tax adjustments	(71)	(31)	(1)
<b>Operating loss adjusted for unusual items</b>	<b>\$ (162)</b>	<b>\$ (153)</b>	<b>\$ (113)</b>
Cash flow from operating activities before changes in non-cash working capital	\$ (218)	\$ (225)	\$ (106)

### 2006 COMPARED WITH 2005

Shared Services recorded an operating loss adjusted for unusual items of \$162 million in 2006, compared with a loss of \$153 million in 2005.

Shared Services net loss was \$263 million in 2006, compared with a net loss of \$177 million in 2005. The 2006 net loss included a \$71 million charge for income tax adjustments and a \$31 million charge related to the mark-to-market valuation of stock-based compensation. The 2005 net loss included a \$73 million gain on foreign currency translation related to long-term debt, a \$66 million charge related to the mark-to-market valuation of stock-based compensation and a \$31 million charge related to income tax adjustments.

# Financial Reporting

## CRITICAL ACCOUNTING ESTIMATES

The preparation of the Company's financial statements requires management to adopt accounting policies that involve the use of significant estimates and assumptions. These estimates and assumptions are developed based on the best available information and are believed by management to be reasonable under the existing circumstances. New events or additional information may result in the revision of these estimates over time. The Audit, Finance and Risk Committee of the Board of Directors regularly reviews the Company's critical accounting policies and any significant changes thereto. A summary of the significant accounting policies used by Petro-Canada can be found in Note 1 to the 2006 Consolidated Financial Statements. The following discussion outlines what management believes to be the most critical accounting policies involving the use of significant estimates or assumptions.

### **Property, Plant and Equipment/Depreciation, Depletion and Amortization**

Investments in exploration and development activities are accounted for under the successful efforts method. Under this method, the acquisition costs of unproved acreage; the costs of exploratory wells pending determination of proved reserves; and the costs of wells, which are assigned proved reserves and development costs, including costs of all wells, are capitalized. The cost of unsuccessful wells and all other exploration costs, including geological and geophysical costs, are charged to earnings as incurred. Capitalized costs of oil and gas producing properties are depreciated and depleted using the unit of production method based upon estimated reserves (see Estimated Oil and Gas Reserves discussion on page 42). Reserves estimates can have a significant impact on net earnings, because they are a key component in the calculation of depreciation and depletion related to the capitalized costs of property, plant and equipment. A revision in reserves estimates could result in a higher or lower depreciation and depletion charge to net earnings. A downward revision in reserves could result in a write-down of oil and gas producing properties as part of the impairment assessment (see Asset Impairment discussion below).

### **Asset Retirement Obligations**

The Company currently records the obligation for estimated asset retirement costs at fair value when incurred. Factors that can affect the fair values of the obligations include the expected costs to be incurred, the useful lives of the assets and discount rates applied. Cost estimates are influenced by factors such as the number and type of assets subject to asset retirement obligations, the extent of work required and changes in environmental legislation. A revision to the estimated costs to be incurred, useful lives of the assets or discount rates applied could result in an increase or decrease in the total obligation, which would change the amount of amortization and accretion expense recognized in net earnings over time.

### **Asset Impairment**

Producing properties and significant unproved properties are assessed annually, or as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated net undiscounted future cash flows to the carrying value of the asset. The cash flows used in the impairment assessment require management to make assumptions and estimates about recoverable reserves (see Estimated Oil and Gas Reserves discussion on page 42), future commodity prices and operating costs. Changes in any of the assumptions, such as a downward revision in reserves, a decrease in future commodity prices or an increase in operating costs, could result in an impairment of an asset's carrying value.

### **Purchase Price Allocation**

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

### **Goodwill Impairment**

Goodwill is subject to impairment tests annually, or as economic events dictate, by comparing the fair value of the reporting unit to its carrying value, including goodwill. If the fair value of the reporting unit is less than its carrying value, a goodwill impairment loss is recognized as the excess of the carrying value of the goodwill over the fair value of the goodwill. The determination of fair value requires management to make assumptions and estimates about recoverable reserves (see Estimated Oil and Gas Reserves discussion below), future commodity prices, operating costs, production profiles and discount rates. Changes in any of these assumptions, such as a downward revision in reserves, a decrease in future commodity prices, an increase in operating costs or an increase in discount rates, could result in an impairment of all or a portion of the goodwill carrying value in future periods.

### **Estimated Oil and Gas Reserves**

Reserves estimates, although not reported as part of the Company's Consolidated Financial Statements, can have a significant effect on net earnings as a result of their impact on depreciation and depletion rates, asset impairments and goodwill impairments (see discussion of these items above and on page 41). The Company's staff of qualified reserves evaluators performs internal evaluations on all of its oil and gas reserves on an annual basis using corporate-wide policies, procedures and practices. Independent qualified petroleum reservoir engineering consultants also conduct annual evaluations, technical audits and/or reviews of a significant portion of the Company's reserves and audit the Company's reserves policies, procedures and practices. In addition, the Company's contract internal auditors test the non-engineering management control processes used in establishing reserves. However, the estimation of reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions, such as geoscientific interpretation, economic conditions, commodity prices, operating and capital costs, and production forecasts, all of which may vary considerably from actual results. These estimates are expected to be revised upward or downward over time as additional information, such as reservoir performance, becomes available or as economic conditions change.

### **Employee Future Benefits**

The Company maintains defined benefit pension plans and provides certain post-retirement benefits to qualifying retirees. The cost of pension and other post-retirement benefits are actuarially determined by an independent actuary using the projected benefit method, pro-rated based on service. The determination of these costs requires management to estimate or make assumptions regarding the expected plan investment performance, salary escalation, retirement ages of employees, expected health care costs, employee turnover and discount rates. Changes in these estimates or assumptions could result in an increase or decrease to the accrued benefit obligation and the related costs for both pensions and other post-retirement benefits.

### **Income Taxes**

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

### **Contingencies**

The Company is involved in litigation and claims in the normal course of operations. Management is of the opinion that any resulting settlements would not materially affect the financial position of the Company as at December 31, 2006. However, the determination of contingent liabilities relating to litigation and claims is a complex process that involves judgments as to the outcomes and interpretation of laws and regulations. Changes in the judgments or interpretations may result in an increase or decrease in the Company's contingent liabilities in the future.

### **SHARE DATA**

The authorized share capital of Petro-Canada consists of an unlimited number of common shares and an unlimited number of preferred shares issuable in series designated as either senior preferred shares or junior preferred shares. As at March 1, 2007, there were 497,132,045 common shares outstanding and no preferred shares outstanding. For details of the Company's share capital and stock options outstanding at December 31, 2006, refer to Notes 21 and 22 of the 2006 Consolidated Financial Statements.

### **ADDITIONAL INFORMATION**

Copies of this MD&A and the following Consolidated Financial Statements, as well as the Company's latest AIF and Management Proxy Circular, may be obtained from the Company's website at [www.petro-canada.ca](http://www.petro-canada.ca) or by mail upon request from the Corporate Secretary, 150 – 6 Avenue S.W., Calgary, Alberta, T2P 3E3. Other disclosure documents, and any reports, statements or other information filed by Petro-Canada with the Canadian provincial securities commissions or other similar regulatory authorities, are accessible through the Internet on the Canadian System for Electronic Document Analysis and Retrieval, which is commonly known by the acronym SEDAR, and located at [www.sedar.com](http://www.sedar.com). SEDAR is the Canadian equivalent of the U.S. SEC's Electronic and Document Gathering and Retrieval System, which is commonly known by the acronym EDGAR, and located at [www.sec.gov](http://www.sec.gov).

# Management, Audit, Finance and Risk Committee, and Auditor Reports

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## MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS AND REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The preparation and presentation of the Company's Consolidated Financial Statements and the overall quality of the Company's financial reporting are the responsibility of management. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) and necessarily include estimates, which are based on management's best judgments. Information contained elsewhere in the Annual Report is consistent, where applicable, with that contained in the financial statements.

Management is also responsible for establishing and maintaining a system of internal controls over financial reporting to provide reasonable assurance that assets are safeguarded and that reliable financial information is produced for preparation of financial statements. Management conducted an evaluation of the effectiveness of the system of internal control over financial reporting based on the framework in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's system of internal control over financial reporting was effective as at December 31, 2006.

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

Management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006 has been audited by Deloitte & Touche LLP, the Company's Independent Registered Chartered Accountants, who also audited the Company's Consolidated Financial Statements for the year ended December 31, 2006. The Report of Independent Registered Chartered Accountants expresses an unqualified opinion on management's assessment of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2006.

The Board of Directors is responsible for overseeing management's performance of its responsibilities for financial reporting and internal control. The Board of Directors exercises this responsibility with the assistance of the Audit, Finance and Risk Committee of the Board of Directors.



Ron A. Brenneman  
*President and Chief Executive Officer*

February 12, 2007



E.F.H. Roberts  
*Executive Vice-President and Chief Financial Officer*

February 12, 2007

## AUDIT, FINANCE AND RISK COMMITTEE OF THE BOARD OF DIRECTORS

The Audit, Finance and Risk Committee (the Committee), which is composed of not fewer than three (currently five) independent directors, assists the Board of Directors in the discharge of its responsibility for overseeing management's performance of the financial reporting and internal control responsibilities. The Committee reviews the annual and quarterly Consolidated Financial Statements, accounting policies and the overall quality of the Company's financial reporting, and the financial information contained in prospectuses and in reports filed with regulatory authorities, as required. The Committee also reviews and makes recommendations to the Board of Directors regarding financial matters and oversees the process that management has in place to identify business risks. The Committee members are all independent pursuant to National Instrument 52-110 (N1 52-110), NYSE Corporate Governance Standards and the Sarbanes-Oxley Act of 2002 (SOX), and are financially literate, with one member who has been recognized as a "financial expert" in accordance with SOX requirements.

With respect to the external auditors, the Committee reviews and approves the terms of engagement, the scope and plan for the external audit, and reviews the results of the audit and the Reports of the Independent Registered Chartered Accountants. The external auditors report to the Committee. The Committee discusses the external auditors' independence from management and the Company with the auditors and receives written confirmation of their independence. The Committee also recommends to the Board of Directors the external auditors to be appointed by the shareholders and approves in advance fees for the external auditors' services.

With respect to the contract auditor's engagement to provide internal audit services, the Committee reviews the engagement contract, reviews and approves the scope and plan for the internal audit, receives periodic reports and reviews significant findings and recommendations. The contract auditor reports to the Committee.

Senior management, the external auditors and the contract auditor attend all Audit, Finance and Risk Committee meetings and each is provided with the opportunity to meet privately with the Committee.



Paul D. Melnuk  
*Chairman of the Audit, Finance and Risk Committee*

February 12, 2007

# Management, Audit, Finance and Risk Committee, and Auditor Reports *cont'd*

## REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

*To the Board of Directors and Shareholders of Petro-Canada:*

We have audited management's assessment, included in the accompanying Management's Responsibility for the Financial Statements and Report on Internal Control Over Financial Reporting, that Petro-Canada and subsidiaries (the Company) maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. 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. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit 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. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the 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, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006 is fairly stated, in all material respects, based on the criteria established in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the Consolidated Financial Statements as of and for the year ended December 31, 2006 of the Company and our report dated February 12, 2007 expressed an unqualified opinion on those financial statements and included a separate report titled Comments by Independent Registered Chartered Accountants on Canada-United States of America Reporting Difference referring to a change in accounting principle.



Independent Registered Chartered Accountants  
Calgary, Canada

February 12, 2007

## REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

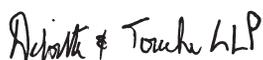
*To the Board of Directors and Shareholders of Petro-Canada:*

We have audited the accompanying Consolidated Balance Sheet of Petro-Canada and subsidiaries as of December 31, 2006 and 2005, and the related Consolidated Statements of Earnings, Retained Earnings and Cash Flows for each of the three years in the period ended December 31, 2006. 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.

With respect to the financial statements for the year ended December 31, 2006, we conducted our audit in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). With respect to the financial statements for the years ended December 31, 2005 and December 31, 2004, we conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such Consolidated Financial Statements present fairly, in all material respects, the financial position of Petro-Canada and subsidiaries as of December 31, 2006 and 2005 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with Canadian generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, based on the criteria established in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 12, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

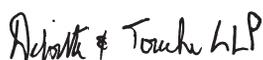


Independent Registered Chartered Accountants  
Calgary, Canada

February 12, 2007

## COMMENTS BY INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS ON CANADA-UNITED STATES OF AMERICA REPORTING DIFFERENCE

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph when there are changes in accounting principles that have a material effect on the comparability of the Company's financial statements, such as the changes described in Note 2 to the Consolidated Financial Statements. Although we conducted our audits in accordance with both Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), our report to the Board of Directors and shareholders on the Consolidated Financial Statements of Petro-Canada, dated February 12, 2007, is expressed in accordance with Canadian reporting standards, which do not require a reference to such changes in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.



Independent Registered Chartered Accountants  
Calgary, Canada

February 12, 2007

## CONSOLIDATED STATEMENT OF EARNINGS

*(stated in millions of Canadian dollars, except per share amounts)*

<i>For the years ended December 31,</i>	2006	2005	2004
<b>REVENUE</b>			
Operating	\$ 18,911	\$ 17,585	\$ 14,270
Investment and other income (expense) <i>(Note 5)</i>	(242)	(806)	(312)
	18,669	16,779	13,958
<b>EXPENSES</b>			
Crude oil and product purchases	9,649	8,846	6,740
Operating, marketing and general <i>(Note 6)</i>	3,180	2,962	2,572
Exploration <i>(Note 15)</i>	339	271	235
Depreciation, depletion and amortization <i>(Notes 6 and 15)</i>	1,365	1,222	1,256
Unrealized gain on translation of foreign currency denominated long-term debt	(1)	(88)	(77)
Interest	165	164	142
	14,697	13,377	10,868
<b>EARNINGS FROM CONTINUING OPERATIONS</b>			
<b>BEFORE INCOME TAXES</b>	3,972	3,402	3,090
<b>PROVISION FOR INCOME TAXES</b> <i>(Note 7)</i>			
Current	2,073	1,794	1,365
Future	311	(85)	27
	2,384	1,709	1,392
<b>NET EARNINGS FROM CONTINUING OPERATIONS</b>	1,588	1,693	1,698
<b>NET EARNINGS FROM DISCONTINUED OPERATIONS</b> <i>(Note 4)</i>	152	98	59
<b>NET EARNINGS</b>	\$ 1,740	\$ 1,791	\$ 1,757
<b>EARNINGS PER SHARE FROM CONTINUING OPERATIONS</b> <i>(Note 8)</i>			
Basic	\$ 3.15	\$ 3.27	\$ 3.21
Diluted	\$ 3.11	\$ 3.22	\$ 3.17
<b>EARNINGS PER SHARE</b> <i>(Note 8)</i>			
Basic	\$ 3.45	\$ 3.45	\$ 3.32
Diluted	\$ 3.41	\$ 3.41	\$ 3.28

## CONSOLIDATED STATEMENT OF RETAINED EARNINGS

*(stated in millions of Canadian dollars)*

<i>For the years ended December 31,</i>	2006	2005	2004
<b>RETAINED EARNINGS AT BEGINNING OF YEAR</b>	\$ 7,018	\$ 5,408	\$ 3,810
Net earnings	1,740	1,791	1,757
Dividends on common shares	(201)	(181)	(159)
<b>RETAINED EARNINGS AT END OF YEAR</b>	\$ 8,557	\$ 7,018	\$ 5,408

See accompanying Notes to Consolidated Financial Statements

# CONSOLIDATED STATEMENT OF CASH FLOWS

*[stated in millions of Canadian dollars]*

<i>For the years ended December 31,</i>	<b>2006</b>	2005	2004
<b>OPERATING ACTIVITIES</b>			
Net earnings	\$ 1,740	\$ 1,791	\$ 1,757
Less: Net earnings from discontinued operations	152	98	59
Net earnings from continuing operations	<b>1,588</b>	1,693	1,698
Items not affecting cash flow from continuing operating activities:			
Depreciation, depletion and amortization	1,365	1,222	1,256
Future income taxes	311	(85)	27
Accretion of asset retirement obligations <i>[Note 20]</i>	54	50	50
Unrealized gain on translation of foreign currency denominated long-term debt	(1)	(88)	(77)
Gain on disposal of assets <i>[Note 5]</i>	(30)	(48)	(12)
Unrealized loss associated with the Buzzard derivative contracts <i>[Note 24]</i>	259	889	333
Other	18	14	33
Exploration expenses <i>[Note 15]</i>	123	140	117
Proceeds from sale of accounts receivable <i>[Note 10]</i>	-	80	399
(Increase) decrease in non-cash working capital related to continuing operating activities <i>[Note 9]</i>	(79)	(84)	104
Cash flow from continuing operating activities	<b>3,608</b>	3,783	3,928
Cash flow from discontinued operating activities <i>[Note 4]</i>	15	204	233
Cash flow from operating activities	<b>3,623</b>	3,987	4,161
<b>INVESTING ACTIVITIES</b>			
Expenditures on property, plant and equipment and exploration <i>[Note 15]</i>	(3,435)	(3,606)	(3,955)
Proceeds from sale of assets <i>[Note 4]</i>	688	81	44
Increase in deferred charges and other assets	(50)	(70)	(36)
Acquisition of Prima Energy Corporation <i>[Note 12]</i>	-	-	(644)
Decrease in non-cash working capital related to investing activities <i>[Note 9]</i>	59	237	10
Cash flow used in investing activities	<b>(2,738)</b>	(3,358)	(4,581)
<b>FINANCING ACTIVITIES</b>			
Increase (decrease) in short-term notes payable	-	(303)	314
Proceeds from issue of long-term debt <i>[Note 18]</i>	-	762	533
Repayment of long-term debt	(7)	(6)	(299)
Proceeds from issue of common shares <i>[Note 21]</i>	44	64	39
Purchase of common shares <i>[Note 21]</i>	(1,011)	(346)	(447)
Dividends on common shares	(201)	(181)	(159)
Increase in non-cash working capital related to financing activities <i>[Note 9]</i>	-	-	(26)
Cash flow used in financing activities	<b>(1,175)</b>	(10)	(45)
<b>(DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS</b>	<b>(290)</b>	619	(465)
<b>CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR</b>	<b>789</b>	170	635
<b>CASH AND CASH EQUIVALENTS AT END OF YEAR</b> <i>[Note 13]</i>	<b>\$ 499</b>	<b>\$ 789</b>	<b>\$ 170</b>
<b>CASH AND CASH EQUIVALENTS - DISCONTINUED OPERATIONS</b> <i>[Note 4]</i>	<b>\$ -</b>	<b>\$ 68</b>	<b>\$ 206</b>
<b>CASH AND CASH EQUIVALENTS - CONTINUING OPERATIONS</b>	<b>\$ 499</b>	<b>\$ 721</b>	<b>\$ (36)</b>

See accompanying Notes to Consolidated Financial Statements

# CONSOLIDATED BALANCE SHEET

(stated in millions of Canadian dollars)

As at December 31,	2006	2005
<b>ASSETS</b>		
<b>CURRENT ASSETS</b>		
Cash and cash equivalents (Note 13)	\$ 499	\$ 721
Accounts receivable (Note 10)	1,600	1,617
Inventories (Note 14)	632	596
Future income taxes (Note 7)	95	-
Assets of discontinued operations (Note 4)	-	237
	<b>2,826</b>	<b>3,171</b>
<b>PROPERTY, PLANT AND EQUIPMENT, NET</b> (Note 15)	<b>18,577</b>	<b>15,921</b>
<b>GOODWILL</b> (Note 16)	<b>801</b>	<b>737</b>
<b>DEFERRED CHARGES AND OTHER ASSETS</b> (Note 17)	<b>442</b>	<b>415</b>
<b>ASSETS OF DISCONTINUED OPERATIONS</b> (Note 4)	<b>-</b>	<b>411</b>
	<b>\$ 22,646</b>	<b>\$ 20,655</b>
<b>LIABILITIES AND SHAREHOLDERS' EQUITY</b>		
<b>CURRENT LIABILITIES</b>		
Accounts payable and accrued liabilities	\$ 3,319	\$ 2,895
Income taxes payable	22	82
Liabilities of discontinued operations (Note 4)	-	102
Current portion of long-term debt	7	7
	<b>3,348</b>	<b>3,086</b>
<b>LONG-TERM DEBT</b> (Note 18)	<b>2,887</b>	<b>2,906</b>
<b>OTHER LIABILITIES</b> (Note 19)	<b>1,826</b>	<b>1,888</b>
<b>ASSET RETIREMENT OBLIGATIONS</b> (Note 20)	<b>1,170</b>	<b>882</b>
<b>FUTURE INCOME TAXES</b> (Note 7)	<b>2,974</b>	<b>2,405</b>
<b>COMMITMENTS AND CONTINGENT LIABILITIES</b> (Note 25)		
<b>SHAREHOLDERS' EQUITY</b>		
Common shares (Note 21)	1,366	1,362
Contributed surplus (Note 21)	469	1,422
Retained earnings	8,557	7,018
Foreign currency translation adjustment	49	(314)
	<b>10,441</b>	<b>9,488</b>
	<b>\$ 22,646</b>	<b>\$ 20,655</b>

See accompanying Notes to Consolidated Financial Statements

Approved on behalf of the Board of Directors



Ron A. Brenneman  
Director



Brian F. MacNeill  
Director

# NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

*(stated in millions of Canadian dollars, unless otherwise stated)*

## Note 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

### (a) Basis of Presentation

The Consolidated Financial Statements include the accounts of Petro-Canada and all subsidiary companies (the Company) and are prepared in accordance with Canadian generally accepted accounting principles (GAAP). Differences between Canadian and United States GAAP are explained in Note 27.

Substantially all of the Company's exploration and development activities are conducted jointly with others. Only the Company's proportionate interests in such activities are reflected in the Consolidated Financial Statements.

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

### (b) Revenue Recognition

Revenue from the sale of crude oil, natural gas, natural gas liquids, purchased products and refined petroleum products is recorded when title passes to the customer. Revenue represents the Company's share and is recorded net of royalty payments to governments and other mineral interest owners. Inter-segment sales are accounted for at market values and included, for segmented reporting, in revenues of the segment making the transfer and expenses of the segment receiving the transfer; these amounts are eliminated on consolidation.

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

### (c) Transportation Costs

Transportation costs incurred to transport crude oil, natural gas and refined products to customers, which are included in operating marketing and general expenses, are recognized when the product is delivered and the service is provided.

**(d) Foreign Currency Translation**

Monetary assets and liabilities are translated into Canadian dollars at rates of exchange in effect at the balance sheet date. With the exception of items pertaining to self-sustaining operations, the other assets and related depreciation, depletion and amortization, other liabilities, revenue and other expense items are translated into Canadian dollars at rates of exchange in effect at the respective transaction dates. The resulting exchange gains or losses are included in earnings.

The Company's International business segment and the U.S. Rockies upstream operations included in the North American Natural Gas business segment are operated on a self-sustaining basis. Assets and liabilities of these operations, including associated long-term debt, are translated into Canadian dollars at period end exchange rates, while revenues and expenses are converted using average rates for the period. Gains and losses from the translation into Canadian dollars are deferred and included in the foreign currency translation adjustment as part of shareholders' equity.

**(e) Income Taxes**

The Company follows the liability method of accounting for income taxes. Under this method, future income taxes are recognized, using substantively enacted income tax rates, based on the temporary differences between the carrying amounts of assets and liabilities reported in the financial statements and their respective tax bases. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in income in the period the change occurs.

**(f) Earnings Per Share**

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

**(g) Cash and Cash Equivalents**

Cash and cash equivalents comprise cash in banks, less outstanding cheques, and short-term investments with a maturity of 90 days or less when purchased. Short-term investments are recorded at the lower of cost or market value.

**(h) Sale of Accounts Receivable**

The transfers of accounts receivable are accounted for as sales, other than the retained interest, when the Company has surrendered control over the transferred receivables and received proceeds. Gains or losses are recognized as other income or expenses and are dependent upon the purchase discount as well as the previous carrying amount of the receivables transferred, which is allocated between the receivables sold and the retained interest, based on their relative fair values at the date of the transfer. Fair value is determined based on the present value of future expected cash flows.

**(i) Inventories**

Inventories are stated at the lower of cost and net realizable value. Cost of crude oil and refined products is determined primarily on a “last-in, first-out” (LIFO) basis. Cost of other inventory is determined primarily on an average cost basis. Costs include direct and indirect expenditures incurred in bringing an item or product to its existing condition and location.

**(j) Investments**

Investments in companies over which the Company has significant influence are accounted for using the equity method. Other long-term investments are accounted for using the cost method.

**(k) Property, Plant and Equipment**

Investments in exploration and development activities are accounted for using the successful efforts method. Under this method, the acquisition cost of unproved acreage is capitalized. Costs of exploratory wells are initially capitalized pending determination of proved reserves. Costs of wells which are assigned proved reserves remain capitalized, while costs of unsuccessful wells are charged to earnings. All other exploration costs, including geological and geophysical costs, are charged to earnings as incurred. Development costs, including the cost of all wells, are capitalized.

Maintenance and repair costs, including planned major maintenance, are expensed as incurred.

The interest cost of debt attributable to the construction of major new facilities is capitalized during the construction period.

Producing properties and significant unproved properties are assessed annually, or as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated net undiscounted future cash flows to the carrying value of the asset. If required, the impairment recorded is the amount by which the carrying value of the asset exceeds its fair value.

**(l) Depreciation, Depletion and Amortization**

Depreciation and depletion of capitalized costs of oil and gas producing properties are calculated using the unit of production method. Development and exploration drilling and equipment costs are depleted over the remaining proved developed reserves and proved property acquisition costs over the remaining proved reserves.

Depreciation of other plant and equipment is provided on either the unit of production method or the straight line method, as appropriate. Straight line depreciation is based on the estimated service lives of the related assets, which range from three to 25 years.

Deferred financing costs are amortized on a straight line basis over the term of the related liability.

Costs associated with significant development projects are not depleted until commencement of commercial production.

**(m) Asset Retirement Obligations**

The fair values of estimated asset retirement obligations are recorded as liabilities when incurred and the associated cost is capitalized as part of the cost of the related asset. Over time, the liabilities are accreted for the change in their present value and the initial capitalized costs are depreciated over the useful lives of the related assets. The associated accretion is recorded in operating expense and the depreciation is included in depreciation, depletion and amortization expense. Actual expenditures incurred are charged against the accumulated obligation.

**(n) Goodwill**

Acquisitions are accounted for using the purchase method. Under this method, identifiable assets and liabilities are recorded at fair value as of the date of acquisition. Goodwill, which is not amortized, is the excess of the purchase price over such fair value and is assigned to one or more reporting units.

The carrying value of goodwill is assessed for impairment annually at year end, or more frequently as economic events dictate, by comparing the fair value of the reporting unit to its carrying value, including goodwill. If the fair value of the reporting unit is less than its carrying value, a goodwill impairment is recognized as the excess of the carrying value of the goodwill over the fair value of the goodwill.

**(o) Stock-Based Compensation**

The Company maintains stock option, performance share unit (PSU) and deferred stock unit (DSU) plans as described in Note 22.

The Company accounts for stock options granted prior to 2003 based on the intrinsic value at the grant date, which does not result in a charge to earnings because the exercise price was equal to the market price at grant date.

Stock options granted in 2003 are accounted for using the fair value method. Fair values are determined, at the grant date, using the Black-Scholes option-pricing model. The compensation expense associated with these options is charged to earnings over the vesting period with a corresponding increase in contributed surplus. On the exercise of stock options, consideration paid and the associated contributed surplus is credited to common shares.

Stock options granted subsequent to 2003, which provide the holder the right to exercise the stock option or surrender the option for a cash payment, are accounted for based on the intrinsic value at each period end whereby a liability and expense are recorded over the vesting period in the amount by which the then current market price exceeds the option exercise price. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares, consideration paid by the stock option holder and the previously recognized liability associated with the stock options are recorded as share capital.

PSUs are accounted for on a mark-to-market basis over the term of the PSUs whereby a liability and expense are recorded based on the number of PSUs outstanding, the current market price of the Company's shares and the Company's current total shareholder return relative to the selected industry peer group.

DSUs are accounted for on a mark-to-market basis whereby a liability and expense are recorded each period based on the number of DSUs outstanding and the current market price of the Company's shares.

**(p) Employee Future Benefits**

The Company's employee future benefit programs consist of both defined benefit and defined contribution pension plans, as well as other post-retirement benefits as described in Note 23.

The costs of pensions and other post-retirement benefits are actuarially determined using the projected benefit method pro-rated based on service and using management's best estimate of expected plan investment performance, discount rates, salary escalation, retirement ages of employees and expected health care costs. For the purpose of calculating the expected return on plan assets, those assets are measured at fair value. The accrued benefit obligation is discounted using a market rate of interest at the end of the year on high quality corporate debt instruments. The excess of the cumulative unamortized net actuarial gain or loss over 10% of the greater of the accrued benefit obligation and the fair value of plan assets at the beginning of the year is amortized over the average remaining service life of active employees.

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

**(q) Hedging and Derivative Financial Instruments**

The Company may use derivative financial instruments to manage its exposure to market risks resulting from fluctuations in foreign exchange rates, interest rates and commodity prices. These derivative financial instruments are not used for speculative purposes and a system of controls is maintained that includes a policy covering the authorization, reporting and monitoring of derivative activity.

Derivative instruments that are not designated as hedges for accounting purposes are recorded on the Consolidated Balance Sheet at fair value with any resulting gain or loss recognized in the Consolidated Statement of Earnings in the current period.

The Company formally documents all derivative instruments designated as hedges, the risk management objective and the strategy for undertaking the hedge.

Gains and losses on derivatives that are designated as, and determined to be, effective hedges are deferred and recognized in the period of settlement as a component of the related transaction. The Company assesses, both at inception and over the term of the hedging relationship, whether the derivative instruments used in the hedging transactions are highly effective in offsetting changes in the fair value or cash flows of hedged items. If a derivative instrument ceases to be effective or is terminated, hedge accounting is discontinued. As long as the underlying transaction continues to be probable of occurring, the accumulated gains and losses continue to be deferred and recognized in the Consolidated Statement of Earnings in the period of settlement of the related transaction; future gains or losses are recognized in the Consolidated Statement of Earnings in the period they occur.

Note 2 **CHANGES IN ACCOUNTING POLICIES**

***Stock-Based Compensation for Employees Eligible to Retire Before the Vesting Date***

The Company has adopted the recommendations of Emerging Issues Committee Abstract 162, *Stock-based compensation for employees eligible to retire before the vesting date* (EIC 162), for the year ended December 31, 2006. The abstract requires that the compensation cost for a stock option attributable to an employee who is eligible to retire at the grant date be recognized on the grant date if the employee can retire from the entity at any point and the ability to exercise the award does not depend on continued service. It further requires that the compensation cost for a stock option award attributable to an employee who will become eligible to retire during the vesting period be recognized over the period from the grant date to the date the employee becomes eligible to retire.

Previously, stock-based compensation was recognized over the applicable vesting period, without regard to when an employee was eligible to retire. During the year ended December 31, 2006, the Company recorded a cumulative adjustment of \$5 million to reflect additional stock-based compensation expense upon adoption of EIC 162. Comparative balances have not been restated as the impact on prior periods is not significant.

Note 3 **SEGMENTED INFORMATION FROM CONTINUING OPERATIONS**

The Company is an integrated oil and gas company with activities spanning both the upstream and downstream sectors of the industry. The Company conducts its business through five major operating business segments along with Shared Services. Upstream activities are conducted through four business segments, which include North American Natural Gas, East Coast Oil, Oil Sands and International; Downstream operations comprise the fifth business segment.

Upstream operations include the exploration, development, production, transportation and marketing of crude oil, natural gas and natural gas liquids and oil sands. The North American Natural Gas segment includes activity in Western Canada, the U.S. Rockies, the Mackenzie Delta/Corridor, Offshore Nova Scotia and Alaska. The East Coast Oil segment comprises activity offshore Newfoundland and Labrador, and includes interests in the Hibernia, Terra Nova, and White Rose oilfield operations. The Oil Sands segment includes an interest in the Syncrude oil sands mining operation, the MacKay River *in situ* oil sands operation, and an interest in the Fort Hills oil sands mining project.

	UPSTREAM								
	NORTH AMERICAN NATURAL GAS			EAST COAST OIL			OIL SANDS		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
<b>Revenue<sup>1</sup></b>									
Sales to customers	\$ 1,504	\$ 2,073	\$ 1,770	\$ 2,004	\$ 1,284	\$ 914	\$ 592	\$ 749	\$ 412
Investment and other income (expense) <sup>2</sup>	6	21	3	-	(2)	(3)	-	4	-
Inter-segment sales	349	345	215	298	346	527	822	660	548
Segmented revenue	1,859	2,439	1,988	2,302	1,628	1,438	1,414	1,413	960
<b>Expenses</b>									
Crude oil and product purchases	256	466	359	452	48	-	425	571	291
Inter-segment transactions	5	7	9	9	6	5	31	80	49
Operating, marketing and general	462	426	379	245	158	120	508	423	362
Exploration	150	118	119	12	4	2	21	32	16
Depreciation, depletion and amortization	402	364	321	237	259	268	128	133	69
Unrealized gain on translation of foreign currency denominated long-term debt	-	-	-	-	-	-	-	-	-
Interest	-	-	-	-	-	-	-	-	-
	1,275	1,381	1,187	955	475	395	1,113	1,239	787
<b>Earnings (loss) from continuing operations before income taxes</b>	<b>584</b>	<b>1,058</b>	<b>801</b>	<b>1,347</b>	<b>1,153</b>	<b>1,043</b>	<b>301</b>	<b>174</b>	<b>173</b>
<b>Provision for income taxes</b>									
Current	351	311	330	434	361	323	(53)	(45)	(71)
Future (Note 7)	(172)	73	(29)	(21)	17	9	109	104	124
	179	384	301	413	378	332	56	59	53
<b>Net earnings (loss) from continuing operations</b>	<b>\$ 405</b>	<b>\$ 674</b>	<b>\$ 500</b>	<b>\$ 934</b>	<b>\$ 775</b>	<b>\$ 711</b>	<b>\$ 245</b>	<b>\$ 115</b>	<b>\$ 120</b>
<b>Capital and exploration expenditures from continuing operations</b>									
Property, plant and equipment and exploration expenditures	\$ 788	\$ 713	\$ 666	\$ 256	\$ 314	\$ 275	\$ 377	\$ 772	\$ 397
Deferred charges and other assets	5	7	6	-	1	1	1	1	-
Acquisition of Prima Energy Corporation, including goodwill	-	-	644	-	-	-	-	-	-
	\$ 793	\$ 720	\$ 1,316	\$ 256	\$ 315	\$ 276	\$ 378	\$ 773	\$ 397
<b>Cash flow from continuing operating activities</b>	<b>\$ 651</b>	<b>\$ 1,219</b>	<b>\$ 899</b>	<b>\$ 1,129</b>	<b>\$ 1,002</b>	<b>\$ 1,018</b>	<b>\$ 499</b>	<b>\$ 340</b>	<b>\$ 384</b>
<b>Total assets from continuing operations</b>	<b>\$ 4,151</b>	<b>\$ 3,763</b>	<b>\$ 3,477</b>	<b>\$ 2,465</b>	<b>\$ 2,442</b>	<b>\$ 2,265</b>	<b>\$ 2,885</b>	<b>\$ 2,623</b>	<b>\$ 1,883</b>

Note 3 **SEGMENTED INFORMATION FROM CONTINUING OPERATIONS** *continued*

The International segment includes activity in the United Kingdom (U.K.), the Netherlands, Trinidad and Tobago, Venezuela, Libya, Algeria, Tunisia, Denmark, Norway, Morocco and Syria. The producing assets in Syria, previously included in the International segment, have been accounted for as a discontinued operation (Note 4).

The Downstream business segment includes the purchase and sale of crude oil, the refining of crude oil products and the distribution and marketing of these and other purchased products.

Financial information by business segment is presented in the following table as though each segment was a separate business entity. Inter-segment transfers of products, which are accounted for at market value, are eliminated on consolidation. Shared Services includes investment income, interest expense, unrealized gains or losses on translation of foreign currency denominated long-term debt and general corporate revenue and expenses. Shared Services assets are principally cash and cash equivalents and other general corporate assets.

INTERNATIONAL			DOWNSTREAM			SHARED SERVICES			CONSOLIDATED		
2006	2005	2004	2006	2005	2004	2006	2005	2004	2006	2005	2004
\$ 2,464	\$ 2,183	\$ 1,767	\$ 12,347	\$ 11,296	\$ 9,407	\$ -	\$ -	\$ -	\$ 18,911	\$ 17,585	\$ 14,270
(283)	(851)	(335)	19	43	13	16	(21)	10	(242)	(806)	(312)
-	-	-	15	13	14	-	-	-	-	-	-
2,181	1,332	1,432	12,381	11,352	9,434	16	(21)	10	18,669	16,779	13,958
-	-	-	8,517	7,762	6,093	(1)	(1)	(3)	9,649	8,846	6,740
-	-	-	1,439	1,271	1,241	-	-	-	-	-	-
350	364	319	1,495	1,436	1,328	120	155	64	3,180	2,962	2,572
156	117	98	-	-	-	-	-	-	339	271	235
323	249	320	262	216	277	13	1	1	1,365	1,222	1,256
-	-	-	-	-	-	(1)	(88)	(77)	(1)	(88)	(77)
-	-	-	-	-	-	165	164	142	165	164	142
829	730	737	11,713	10,685	8,939	296	231	127	14,697	13,377	10,868
1,352	602	695	668	667	495	(280)	(252)	(117)	3,972	3,402	3,090
1,248	1,015	631	141	264	226	(48)	(112)	(74)	2,073	1,794	1,365
310	(304)	(52)	54	(12)	(45)	31	37	20	311	(85)	27
1,558	711	579	195	252	181	(17)	(75)	(54)	2,384	1,709	1,392
\$ (206)	\$ (109)	\$ 116	\$ 473	\$ 415	\$ 314	\$ (263)	\$ (177)	\$ (63)	\$ 1,588	\$ 1,693	\$ 1,698
\$ 760	\$ 696	\$ 1,707	\$ 1,229	\$ 1,053	\$ 839	\$ 24	\$ 12	\$ 9	\$ 3,434	\$ 3,560	\$ 3,893
-	-	-	22	33	26	22	28	3	50	70	36
-	-	-	-	-	-	-	-	-	-	-	644
\$ 760	\$ 696	\$ 1,707	\$ 1,251	\$ 1,086	\$ 865	\$ 46	\$ 40	\$ 12	\$ 3,484	\$ 3,630	\$ 4,573
\$ 840	\$ 722	\$ 789	\$ 835	\$ 663	\$ 879	\$ (346)	\$ (163)	\$ (41)	\$ 3,608	\$ 3,783	\$ 3,928
\$ 6,031	\$ 4,856	\$ 4,969	\$ 6,649	\$ 5,609	\$ 4,462	\$ 465	\$ 714	\$ 95	\$ 22,646	\$ 20,007	\$ 17,151

1 There were no customers that represented 10% or more of the Company's consolidated revenues for the periods presented.

2 Investment and other income for the International segment includes \$259 million (2005 – \$889 million; 2004 – \$333 million) of unrealized losses relating to the Buzzard derivative contracts (Note 24).

**Geographic Information from Continuing Operations**

	2006		2005		2004	
	Revenues	Total Assets	Revenues	Total Assets	Revenues	Total Assets
Canada	\$ 16,295	\$ 14,736	\$ 15,302	\$ 14,261	\$ 12,472	\$ 11,263
Foreign <sup>1</sup>	2,374	7,910	1,477	5,746	1,486	5,888
	\$ 18,669	\$ 22,646	\$ 16,779	\$ 20,007	\$ 13,958	\$ 17,151

1 Foreign total assets include \$3,692 million relating to assets in the U.K. (2005 – \$2,964 million; 2004 – \$1,002 million).

Note 4 **DISCONTINUED OPERATIONS**

On January 31, 2006, the Company completed the sale of its producing assets in Syria for net proceeds of \$640 million, resulting in a gain on disposal of \$134 million.

The accounting for discontinued operations results in a reduction of the Consolidated Statement of Earnings balances as follows:

	2006	2005	2004
<b>Revenue</b>	\$ 168 <sup>1</sup>	\$ 464	\$ 419
<b>Expenses</b>			
Operating, marketing and general	6	104	118
Depreciation, depletion and amortization	–	145	146
	6	249	264
Earnings from discontinued operations before income taxes	162	215	155
Provision for income taxes	10	117	96
Net earnings from discontinued operations	\$ 152	\$ 98	\$ 59

The assets and liabilities of the discontinued operations are comprised of the following:

	2006	2005
<b>Assets</b>		
Current assets	\$ –	\$ 237 <sup>2</sup>
Property, plant and equipment, net	–	300
Goodwill	–	111
Total assets	\$ –	\$ 648
<b>Liabilities</b>		
Current liabilities	\$ –	\$ 102
Net assets of discontinued operations	\$ –	\$ 546

1 Revenue includes the gain on disposal of \$134 million.

2 Current assets include cash and cash equivalents of \$68 million as at December 31, 2005.

Note 5 **INVESTMENT AND OTHER INCOME (EXPENSE)**

Investment and other income includes net losses on derivative contracts (Note 24) of \$257 million (2005 – \$882 million; 2004 – \$345 million) and net gains on disposal of assets of \$30 million (2005 – \$48 million; 2004 – \$12 million) for the year ended December 31, 2006.

Note 6 **ASSET WRITE-DOWNS**

**Oakville Refining Operations**

Petro-Canada announced in September 2003 it would cease the Oakville refining operations and expand the existing terminalling facilities. The shutdown of the refinery was completed in April 2005. The total charge to earnings related to the shutdown over the three years was \$195 million after-tax. The following expenses have been recorded in the Downstream segment:

	2006		2005		2004	
	Pre-Tax	After-Tax	Pre-Tax	After-Tax	Pre-Tax	After-Tax
Operating, marketing and general expenses (de-commissioning and employee-related costs)	\$ -	\$ -	\$ (4)	\$ (2)	\$ 3	\$ 2
Depreciation and amortization expenses (asset write-downs and increased depreciation)	-	-	1	-	71	44
	\$ -	\$ -	\$ (3)	\$ (2)	\$ 74	\$ 46

Note 7 **INCOME TAXES**

The computation of the provision for income taxes is as follows:

	2006	2005	2004
Earnings from continuing operations before income taxes	\$ 3,972	\$ 3,402	\$ 3,090
Add (deduct):			
Non-deductible royalties and other payments to provincial governments, net	61	393	352
Resource allowance	(158)	(413)	(512)
Non-taxable foreign exchange	(11)	(45)	(40)
Other	(24)	5	(10)
Earnings from continuing operations as adjusted before income taxes	\$ 3,850	\$ 3,342	\$ 2,880
Canadian federal income tax rate	38.0%	38.0%	38.0%
Income tax on earnings from continuing operations as adjusted at Canadian federal income tax rate	\$ 1,463	\$ 1,270	\$ 1,094
Provincial income taxes	295	325	271
Federal – abatement and other credits	(262)	(378)	(274)
Current income tax increase due to provincial reassessments	70	-	-
Future income tax increase (decrease) due to Canadian federal and provincial rate changes	(63)	6	(13)
Future income tax increase due to foreign rate changes	242	-	-
Higher foreign income tax rates	627	482	320
Income tax credits and other	12	4	(6)
Provision for income taxes	\$ 2,384	\$ 1,709	\$ 1,392
Effective income tax rate on earnings from continuing operations before income taxes	60.0%	50.2%	45.0%

The provision for income taxes is comprised of:

	2006	2005	2004
Current			
Canadian	\$ 801	\$ 769	\$ 734
Foreign	1,272	1,025	631
Future			
Canadian	62	(113)	(54)
Foreign	249	28	81
Total provision for income taxes	\$ 2,384	\$ 1,709	\$ 1,392

The provision for future income taxes for the year ended December 31, 2006 includes a \$242 million charge due to the enacted increase in the U.K. supplemental corporate income tax rate. The adjustment was allocated to the Company's International business segment.

The provision for future income taxes for the year ended December 31, 2006 was reduced by \$63 million due to the enacted reduction in Canadian federal and provincial income tax rates. The adjustment was allocated to the segments as a decrease (increase) to the tax provision as follows: North American Natural Gas – \$6 million, East Coast Oil – \$37 million, Oil Sands – \$44 million, International – \$(64) million, Downstream – \$41 million and Shared Services – \$(1) million.

The provision for current income taxes for the year ended December 31, 2006 was increased by \$70 million due to the Quebec government enacting retroactive tax legislation. The adjustment was allocated to Shared Services.

The following table summarizes the temporary differences that give rise to the net future income tax asset and liability:

	2006	2005
Future income tax liabilities		
Property, plant and equipment	\$ 3,919	\$ 3,114
Partnership income <sup>1</sup>	367	532
Deferred charges and other assets	75	58
Future income tax assets		
Asset retirement obligations and other liabilities	(1,010)	(906)
Inventories	(212)	(230)
Other	(260)	(163)
Future income tax liability	2,879	2,405
Less: Current future income tax asset	(95)	-
Net future income tax liability	\$ 2,974	\$ 2,405

1 Taxable income for certain Canadian upstream activities are generated by a partnership and the related taxes will be included in current income taxes in the next year.

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

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

Note 8 **EARNINGS PER SHARE**

The weighted-average number of common shares outstanding used in the calculations of basic and diluted earnings per share from continuing operations and earnings per share, assuming that all dilutive outstanding stock options were exercised, was:

<i>(millions)</i>	2006	2005	2004
Weighted-average number of common shares			
outstanding – basic	503.9	518.4	529.3
Effect of dilutive stock options	6.0	7.0	6.9
Weighted-average number of common shares			
outstanding – diluted	509.9	525.4	536.2

There were no stock options excluded from the diluted earnings per share from continuing operations and earnings per share calculations. Stock options are excluded when the exercise price exceeds the average share price in a respective period.

## Note 9 CASH FLOW INFORMATION

### Changes in Non-Cash Working Capital

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

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

	2006	2005	2004
<b>Operating activities from continuing operations</b>			
Accounts receivable	\$ 17	\$ (563)	\$ (131)
Inventories	(36)	(18)	4
Accounts payable and accrued liabilities	365	662	266
Income taxes payable	(60)	(190)	96
Current portion of long-term liabilities and other	(365)	25	(131)
	<b>\$ (79)</b>	<b>\$ (84)</b>	<b>\$ 104</b>
<b>Investing activities</b>			
Accounts payable and accrued liabilities	\$ 59	\$ (12)	\$ 10
Other liabilities	-	249	-
	<b>\$ 59</b>	<b>\$ 237</b>	<b>\$ 10</b>
<b>Financing activities</b>			
Accounts payable and accrued liabilities	\$ -	\$ -	\$ (26)

### Cash Payments

Cash payments from continuing operations for interest and income taxes were as follows:

	2006	2005	2004
Interest	\$ 194	\$ 186	\$ 165
Income taxes	\$ 2,149	\$ 1,972	\$ 1,353

## Note 10 SECURITIZATION PROGRAM

In 2004, the Company entered into a securitization program, expiring in 2009, to sell an undivided interest of eligible accounts receivable up to \$400 million to a third party, on a revolving and fully serviced basis. The service liability has been estimated to be insignificant. The Company also retains an interest in the transferred accounts receivable equal to the required reserves amount.

In March 2005, the Company increased the limit to sell eligible accounts receivable under the program from \$400 million to \$500 million. During the year ended December 31, 2005, the Company sold an additional \$80 million of outstanding receivables for net proceeds of \$80 million. As at December 31, 2006, \$480 million (December 31, 2005 – \$480 million) of outstanding accounts receivable had been sold under the program for net proceeds of \$479 million.

## Note 11 FORT HILLS OIL SANDS MINING PROJECT

In June 2005, the Company acquired, for \$300 million, a 60% interest in the Fort Hills oil sands mining project, which was previously wholly owned by UTS Energy Corporation (UTS). As part of the acquisition, Petro-Canada became the project operator. To pay for the investment, Petro-Canada will fund a portion of UTS' share of the next \$2.5 billion of development capital. The discounted value of the acquisition cost was recorded in other liabilities (Note 19).

In November 2005, the Company and UTS finalized agreements with Teck Cominco Limited (Teck Cominco) whereby Teck Cominco acquired a 15% interest in the Fort Hills oil sands mining project with Petro-Canada and UTS holding interests of 55% and 30%, respectively. Petro-Canada remains the project operator.

## Note 12 ACQUISITION OF PRIMA ENERGY CORPORATION

On July 28, 2004, the Company acquired all of the common shares of Prima Energy Corporation, an oil and gas company with operations in the U.S. Rockies, for a total acquisition cost of \$644 million, net of cash acquired. The results of operations were included in the Consolidated Financial Statements from the date of acquisition.

The acquisition was accounted for by the purchase method of accounting. The allocation of fair value to the assets acquired and liabilities assumed was:

Property, plant and equipment	\$	688
Goodwill		193
Current assets, excluding cash of \$74 million		36
Deferred charges and other assets		2
Total assets acquired		919
Current liabilities		41
Future income taxes		217
Asset retirement obligations and other liabilities		17
Total liabilities assumed		275
Net assets acquired	\$	644

Goodwill, which is not tax deductible, was assigned to the Company's North American Natural Gas business segment.

## Note 13 CASH AND CASH EQUIVALENTS

	2006	2005
Cash	\$ 42	\$ 48
Short-term investments	457	741
	499	789
Less: discontinued operations (Note 4)	-	68
	\$ 499	\$ 721

## Note 14 INVENTORIES

	2006	2005
Crude oil, refined products and merchandise	\$ 455	\$ 431
Materials and supplies	177	165
	\$ 632	\$ 596

Note 15 **PROPERTY, PLANT AND EQUIPMENT**

	2006			2005			2006	2005
	Cost	Accumulated Depreciation, Depletion and Amortization	Net	Cost	Accumulated Depreciation, Depletion and Amortization	Net	Expenditures on Property, Plant and Equipment <sup>1,2</sup>	
<b>Upstream</b>								
North American								
Natural Gas	\$ 6,942	\$ 3,189	\$ 3,753	\$ 6,161	\$ 2,828	\$ 3,333	\$ 707	\$ 635
East Coast Oil	3,874	1,594	2,280	3,577	1,359	2,218	248	310
Oil Sands	3,598	908	2,690	3,217	759	2,458	370	745
International	5,863	1,123	4,740	4,245	469	3,776	733	665
	20,277	6,814	13,463	17,200	5,415	11,785	2,058	2,355
<b>Downstream</b>								
Refining	5,333	1,469	3,864	4,254	1,318	2,936	1,083	936
Marketing and other	2,517	1,301	1,216	2,419	1,252	1,167	146	117
	7,850	2,770	5,080	6,673	2,570	4,103	1,229	1,053
<b>Other property, plant and equipment</b>								
	495	461	34	470	437	33	24	12
	\$ 28,622	\$ 10,045	\$ 18,577	\$ 24,343	\$ 8,422	\$ 15,921	\$ 3,311	\$ 3,420

1 Expenditures are from continuing operations and exclude \$1 million (2005 – \$46 million) relating to discontinued operations (Note 4).

2 Exploration expenses, excluding general and administrative and geological and geophysical expenses, of \$123 million (2005 – \$140 million; 2004 – \$117 million) are reclassified from operating activities and included with expenditures on property, plant and equipment and exploration under investing activities in the Consolidated Statement of Cash Flows.

Property, plant and equipment net cost includes asset retirement costs of \$609 million (2005 – \$414 million).

Interest capitalized during 2006 amounted to \$51 million (2005 – \$35 million; 2004 – \$20 million).

Costs of \$62 million (2005 – \$48 million) relating to East Coast Oil projects, \$2,934 million (2005 – \$2,778 million) relating to the International operations, \$1,044 million (2005 – \$1,227 million) relating to Downstream operations, \$152 million (2005 – \$1,190 million) relating to Oil Sands operations and \$211 million (2005 – \$323 million) relating to North American Natural Gas operations are currently not being depleted or depreciated.

Capital leases at a net cost of \$60 million (2005 – \$63 million) and \$23 million (2005 – \$25 million) are included in the assets of East Coast Oil and Oil Sands, respectively (Note 18).

Note 16 **GOODWILL**

The following table summarizes the changes in goodwill:

	2006			2005		
	North American Natural Gas	International	Total	North American Natural Gas	International	Total
Goodwill at beginning of year	\$ 170	\$ 567	\$ 737	\$ 175	\$ 811	\$ 986
Foreign exchange	(1)	65	64	(5)	(133)	(138)
Discontinued operations (Note 4)	-	-	-	-	(111)	(111)
Goodwill at end of year	\$ 169	\$ 632	\$ 801	\$ 170	\$ 567	\$ 737

## Note 17 DEFERRED CHARGES AND OTHER ASSETS

	2006	2005
Investments	\$ 82	\$ 87
Accrued pension asset <i>(Note 23)</i>	128	105
Deferred financing costs	101	108
Other long-term assets	131	115
	<b>\$ 442</b>	<b>\$ 415</b>

## Note 18 LONG-TERM DEBT

	Maturity	2006	2005
Debtures and notes			
5.95% unsecured senior notes (\$600 million US) <sup>1</sup>	2035	\$ 699	\$ 700
5.35% unsecured senior notes (\$300 million US) <sup>2</sup>	2033	349	350
7.00% unsecured debentures (\$250 million US)	2028	291	292
7.875% unsecured debentures (\$275 million US)	2026	321	321
9.25% unsecured debentures (\$300 million US)	2021	349	350
5.00% unsecured senior notes (\$400 million US)	2014	466	466
4.00% unsecured senior notes (\$300 million US) <sup>2</sup>	2013	349	350
Capital leases <i>(Note 15)</i> <sup>3</sup>	2007-2017	70	77
Retail licensee trust loans		-	7
		<b>2,894</b>	2,913
Current portion		<b>(7)</b>	(7)
		<b>\$ 2,887</b>	<b>\$ 2,906</b>

1 In May 2005, the Company issued \$600 million US 5.95% notes due May 15, 2035. The proceeds were used primarily to repay existing short-term notes payable.

2 In anticipation of issuing these senior notes, the Company entered into interest rate derivatives, which resulted in effective interest rates of 6.073% for the 5.35% notes due in 2033 and 4.838% for the 4.00% notes due in 2013.

3 The Company is party to one transportation and one time charter agreement that are accounted for as capital leases and have implicit rates of interest of 14.65% and 11.90%, respectively. The aggregate remaining repayments under the transportation and time charter agreements are \$70 million, including the following amounts in the next five years: 2007 – \$7 million; 2008 – \$2 million; 2009 – \$3 million; 2010 – \$3 million; and 2011 – \$4 million.

Interest on long-term debt, net of capitalized interest, was \$152 million in 2006 (2005 – \$146 million; 2004 – \$132 million).

At December 31, 2006, the Company has in place syndicated operating credit facilities totalling \$2,200 million, maturing in 2012. The syndicated facilities are unsecured, committed revolving facilities that bear interest at either the lenders' rates for Canadian prime loans, U.S. base rate loans, Bankers' Acceptances rates or at London Inter-Bank Offered Rate (LIBOR) plus applicable margins. The Company also has revolving bilateral demand credit facilities of \$829 million at December 31, 2006. A total of \$1,444 million of the credit facilities was used for letters of credit and overdraft coverage at December 31, 2006. The syndicated facilities also provide liquidity support to Petro-Canada's commercial paper program, under which no amounts were outstanding at December 31, 2006.

**Note 19 OTHER LIABILITIES**

	2006	2005
Post-retirement benefits <i>(Note 23)</i>	\$ 182	\$ 173
Unrealized loss on Buzzard derivative contracts <i>(Note 24)</i>	1,252	1,222
Fort Hills purchase obligation <i>(Note 11)</i>	170	247
Other long-term liabilities	222	246
	<b>\$ 1,826</b>	<b>\$ 1,888</b>

**Note 20 ASSET RETIREMENT OBLIGATIONS**

Asset retirement obligations are recorded for obligations where the Company will be required to retire tangible long-lived assets such as well sites, offshore production platforms, natural gas processing plants and marketing sites.

The following table summarizes the changes in the asset retirement obligations:

	2006	2005
Asset retirement obligations at beginning of year	\$ 962	\$ 873
Obligations incurred	95	92
Changes in estimates	138	104
Abandonment expenditures	(55)	(98)
Accretion expense	54	50
Foreign exchange	43	(59)
Asset retirement obligations at end of year	1,237	962
Less: Current portion	(67)	(80)
	<b>\$ 1,170</b>	<b>\$ 882</b>

In determining the fair value of the asset retirement obligations, the estimated cash flows of new obligations incurred during the year have been discounted at 5.5% (2005 – 5.5%). The total undiscounted amount of the estimated cash flows required to settle the obligations is \$3,481 million (2005 – \$2,839 million). The obligations will be settled on an ongoing basis over the useful lives of the operating assets, which extend up to 50 years in the future. The current portion of asset retirement obligations is included in accounts payable and accrued liabilities.

**Note 21 SHAREHOLDERS' EQUITY****Authorized**

The authorized share capital is comprised of an unlimited number of:

- (a) Preferred shares issuable in series designated as Senior Preferred Shares
- (b) Preferred shares issuable in series designated as Junior Preferred Shares
- (c) Common shares without par value

**Issued and Outstanding**

Changes in common shares and contributed surplus were as follows:

	2006			2005		
	Shares	Amount	Contributed Surplus	Shares	Amount	Contributed Surplus
Balance at beginning of year	515,138,904	\$ 1,362	\$ 1,422	519,928,022	\$ 1,314	\$ 1,743
Issued under employee stock-option and share purchase plans	2,177,881	57	5	3,544,282	70	3
Repurchased under normal course issuer bid	(19,778,400)	(53)	(958)	(8,333,400)	(22)	(324)
Balance at end of year	497,538,385	\$ 1,366	\$ 469	515,138,904	\$ 1,362	\$ 1,422

In June 2006, the Company renewed its normal course issuer bid to repurchase up to 25 million of its common shares during the period from June 22, 2006 to June 21, 2007, subject to certain conditions. During 2006, the Company purchased 19,778,400 common shares at an average price of \$51.10 per common share for a total cost of \$1,011 million (2005 – 8,333,400 common shares at an average price of \$41.54 per common share for a total cost of \$346 million). The excess of the purchase price over the carrying amount of the shares purchased, which totalled \$958 million in 2006 (2005 – \$324 million), was recorded as a reduction of contributed surplus.

Note 22 **STOCK-BASED COMPENSATION**

**Stock Options**

The Company maintains a stock option plan whereby options can be granted to officers and certain employees for up to 44 million common shares. Stock options have a term of 10 years if granted prior to 2004 and seven years if granted subsequent to 2003. All stock options vest over periods of up to four years and are exercisable at the market prices for the shares on the dates that the options were granted.

In 2004, the Company amended the option plan to provide the holder of stock options granted subsequent to 2003 the alternative to exercise these options as a cash payment alternative (CPA). Where the CPA is chosen, vested options can be surrendered for cancellation in return for a direct cash payment from the Company based on the excess of the then market price over the option exercise price.

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

	2006		2005		2004	
	Weighted-Average Exercise Price		Weighted-Average Exercise Price		Weighted-Average Exercise Price	
	Number	(dollars)	Number	(dollars)	Number	(dollars)
Balance at beginning of year	18,361,617	\$ 24	18,074,698	\$ 21	17,241,186	\$ 19
Granted	4,911,600	52	4,185,800	35	3,673,400	29
Exercised for common shares	(2,177,881)	20	(3,544,282)	18	(2,492,000)	16
Surrendered for cash payment	(119,710)	31	(47,551)	29	–	–
Cancelled	(260,893)	41	(307,048)	29	(347,888)	22
Balance at end of year	20,714,733	\$ 31	18,361,617	\$ 24	18,074,698	\$ 21

The following stock options were outstanding as at December 31, 2006:

Range of Exercise Prices (dollars)	Options Outstanding			Options Exercisable	
	Number	Weighted-Average Life (years)	Weighted-Average Exercise Price (dollars)	Number	Weighted-Average Exercise Price (dollars)
\$ 8 to 17	3,729,484	3.8	\$ 14	3,729,484	\$ 14
18 to 23	2,117,975	4.2	19	2,117,975	19
24 to 27	3,222,529	5.9	26	2,239,203	26
28 to 32	3,001,770	4.1	29	1,392,070	29
33 to 42	3,868,575	5.1	35	954,050	35
43 to 55	4,774,400	6.1	52	81,900	52
\$ 8 to 55	20,714,733	5.0	\$ 31	10,514,682	\$ 22

During 2006, the Company recorded compensation expense of \$10 million (2005 – \$10 million; 2004 – \$10 million) relating to the 2003 stock options and \$31 million (2005 – \$69 million; 2004 – \$3 million) relating to options with a CPA (Note 2).

**Performance Share Units**

The Company maintains a Performance Share Unit (PSU) plan for officers and other senior management employees. Under the PSU program, notional share units are awarded and settled in cash at the end of a three-year period based upon the Company's share price at that time, the value of notional dividends applied during the period and the Company's total shareholder return relative to a peer group of North American industry competitors.

Changes in the number of outstanding PSUs were as follows:

	2006 Number	2005 Number
Balance at beginning of year	1,158,967	565,860
Granted	385,632	642,940
Exercised	-	-
Cancelled	(61,613)	(49,833)
Balance at end of year	1,482,986	1,158,967

PSUs outstanding at the end of 2004 have a performance period ending in 2007, PSUs issued in 2005 have a performance period ending in 2008 and PSUs issued in 2006 have a performance period ending in 2009. During 2006, the Company recorded compensation (recovery) expense relating to PSUs of \$(4) million (2005 – \$7 million; 2004 – nil).

**Deferred Share Units**

The Company maintains a Deferred Share Unit (DSU) plan whereby executive officers are awarded DSUs and/or can elect to receive all or a portion of their annual incentive compensation in the form of DSUs. Under the officer DSU program, notional share units are issued for the elected amount, which is based on the then current market price of the Company's common shares. Upon termination or retirement, the units are settled in cash, which includes an amount for the value of notional dividends earned over the period the units were outstanding.

The Company's Board of Directors receives a portion of their compensation in the form of DSUs and can also elect to receive all or a portion of their non-DSU compensation in the form of DSUs. Under the Director program, notional share units are issued and settled in cash or common shares, including the value of notional dividends, upon ceasing to be a Director.

During 2006, the Company recorded compensation expense (recovery) relating to DSUs of \$2 million (2005 – \$13 million; 2004 – \$(1) million).

Note 23 **EMPLOYEE FUTURE BENEFITS**

The Company maintains pension plans with defined benefit and defined contribution provisions and provides certain health care and life insurance benefits to its qualifying retirees. The actuarially determined cost of these benefits is accrued over the estimated service life of employees. The defined benefit provisions are generally based upon years of service and average salary during the final years of employment. Certain defined benefit options require employee contributions and the balance of the funding for the registered plans is provided by the Company, based upon the advice of an independent actuary. The accrued benefit obligations and the fair value of plan assets are measured for accounting purposes at December 31 of each year. The most recent actuarial valuation of the pension plan for funding purposes was as of December 31, 2004 and the next required valuation will be as of December 31, 2007.

The defined contribution plan provides for an annual contribution of 5% to 8% of each participating employee's pensionable earnings.

Benefit Plan Expense	Pension Plans			Other Post-Retirement Plans		
	2006	2005	2004	2006	2005	2004
(a) Defined benefit plans						
Employer current service cost	\$ 40	\$ 36	\$ 31	\$ 4	\$ 4	\$ 4
Interest cost	86	86	81	11	12	13
Actual return on plan assets	(154)	(133)	(91)	-	-	-
Actuarial losses (gains)	43	155	97	-	19	(15)
Elements of employee future benefit plan expense before adjustments to recognize the long-term nature of employee future benefit plan expense	15	144	118	15	35	2
Difference between actual and expected return on plan assets	55	45	12	-	-	-
Difference between actual and recognized actuarial losses in year	8	(121)	(67)	2	(19)	16
Amortization of transitional (asset) obligation	(5)	(6)	(5)	2	2	2
	73	62	58	19	18	20
(b) Defined contribution plans	18	16	13			
Total expense	\$ 91	\$ 78	\$ 71	\$ 19	\$ 18	\$ 20
<b>Benefit Plan Funding</b>						
Defined contribution	\$ 18	\$ 16	\$ 13			
Defined benefit	\$ 96	\$ 96	\$ 80	\$ 10	\$ 9	\$ 9

Financial Status of Defined Benefit Plans	Pension Plans		Other Post-Retirement Plans	
	2006	2005	2006	2005
Fair value of plan assets	\$ 1,486	\$ 1,303	\$ -	\$ -
Accrued benefit obligation	1,786	1,681	235	230
Funded status – plan deficit <sup>1</sup>	(300)	(378)	(235)	(230)
Unamortized transitional (asset) obligation	(18)	(23)	13	15
Unamortized net actuarial losses	446	506	40	42
Accrued benefit asset (liability)	\$ 128	\$ 105	\$ (182)	\$ (173)
<b>Reconciliation of Plan Assets</b>				
Fair value of plan assets at beginning of year	\$ 1,303	\$ 1,157	\$ -	\$ -
Contributions	96	96	10	9
Benefits paid	(77)	(83)	(10)	(9)
Actual gain (loss) on plan assets	154	133	-	-
Other	10	-	-	-
Fair value of plan assets at end of year	\$ 1,486	\$ 1,303	\$ -	\$ -
<b>Reconciliation of Accrued Benefit Obligation</b>				
Accrued benefit obligation at beginning of year	\$ 1,681	\$ 1,487	\$ 230	\$ 204
Current service cost	40	36	4	4
Interest cost	86	86	11	12
Benefits paid	(77)	(83)	(10)	(9)
Actuarial losses (gains)	43	155	-	19
Other	13	-	-	-
Accrued benefit obligation at end of year	\$ 1,786	\$ 1,681	\$ 235	\$ 230

1 The pension and other post-retirement plans included in the financial status information are not fully funded.

<b>Defined Benefit and Other Post-Retirement Plans Assumptions</b>	<b>2006</b>	<b>2005</b>	<b>2004</b>
Year-end obligation discount rate <sup>1</sup>	<b>5.0%</b>	5.0%	5.7%
Accrued benefit obligation discount rate <sup>1</sup>	<b>5.0%</b>	5.7%	6.0%
Long-term rate of return on plan assets	<b>7.5%</b>	7.5%	7.5%
Rate of compensation increase, excluding merit increases	<b>3.0%</b>	3.1%	3.0%

<sup>1</sup> Assumption used in both pension and other post-retirement plans.

**Assumed Health and Dental Care Cost Trend Rates at December 31 are as follows:**

	<b>2006</b>	<b>2005</b>
Dental care cost trend rate <sup>1</sup>	<b>3.5%</b>	3.5%
Health care cost trend rate	<b>8.0%</b>	8.5%
Health care cost trend rate declines to	<b>4.5%</b>	4.5%
Year that health care cost trend rate reaches the rate which it is expected to remain at	<b>2014</b>	2014

<sup>1</sup> Dental care cost trend rate assumed to remain constant.

**Sensitivity Analysis**

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects for 2006:

	<b>Increase</b>	<b>Decrease</b>
Total of service and interest cost	\$ 2	\$ (2)
Accrued benefit obligation	\$ 28	\$ (26)

**The Plan Assets consist of:**

<i>Asset Category</i>	Percentage of Plan Assets at December 31,	
	<b>2006</b>	<b>2005</b>
Equity	<b>62%</b>	61%
Bonds	<b>38%</b>	39%
	<b>100%</b>	100%

Note 24 **FINANCIAL INSTRUMENTS AND DERIVATIVES**

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of its business operations. The Company monitors its exposure to market fluctuations and may use derivative instruments to manage these risks, as it considers appropriate.

**Crude Oil and Products**

The Company enters into forward contracts and options to reduce exposure to Downstream margin fluctuations, including margins on fixed-price product sales, and short-term price fluctuations on the purchase of foreign and domestic crude oil and refined products.

The Company has also entered into a series of forward sales contracts for the future sale of Brent crude oil in connection with its 2004 acquisition of an interest in the Buzzard field in the U.K. sector of the North Sea. Unrealized losses relating to these contracts amounted to \$259 million for the year ended December 31, 2006 (2005 – \$889 million; 2004 – \$333 million).

Investment and other income includes unrealized losses on all derivative contracts of \$268 million for the year ended December 31, 2006 (2005 – \$889 million; 2004 – \$338 million).

As at December 31, 2006, the amounts included in the Consolidated Balance Sheet as a result of the unrealized mark-to-market amounts on derivative contracts are as follows:

	December 31, 2006	December 31, 2005
Accounts receivable	\$ -	\$ 5
Accounts payable and accrued liabilities	233	1
Other liabilities	1,252	1,222

The Company's outstanding contracts for derivative instruments and the related fair values at December 31, 2006 were as follows:

	Quantity	Maturity	Average Price US\$/bbl	Fair Value
<b>Crude Oil and Products</b> (millions of barrels)				
Crude oil purchases	2.7	2007	\$ 63.42	\$ (8)
Crude oil sales	2.0	2007	\$ 61.99	\$ 6
Buzzard crude oil sales	35.8	2007-2010	\$ 25.98	\$ (1,481)
				\$ (1,483)

	Quantity	Maturity	Cdn\$/GJ	Fair Value
<b>Natural Gas</b> (millions of gigajoules – GJ)				
Natural gas purchases	1.1	2007	\$ 7.72	\$ (2)
				\$ (2)
				\$ (1,485)

The fair value of these derivative instruments is based on quotes provided by brokers, which represents an approximation of amounts that would be received or paid to counterparties to settle these instruments prior to maturity. The Company plans to hold all derivative instruments outstanding at December 31, 2006 to maturity.

Derivative and financial instruments involve a degree of credit risk. The Company manages this risk through the establishment of credit policies and limits, which are applied in the selection of counterparties. Market risk relating to changes in value or settlement cost of the Company's derivative instruments is essentially offset by gains or losses on the underlying transaction.

In addition to the derivative instruments described above, the Consolidated Balance Sheet includes other items considered to be financial instruments, such as cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, short-term notes payable and long-term debt. The fair values of these other financial instruments included in the Consolidated Balance Sheet are as follows:

	2006		2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial instruments included in current assets and current liabilities related to continuing operations	\$ (1,220)	\$ (1,220)	\$ (557)	\$ (557)
Long-term debt	\$ (2,894)	\$ (2,959)	\$ (2,913)	\$ (3,134)

The fair value of financial instruments included in current assets and current liabilities related to continuing operations, excluding the current portion of long-term debt, approximates the carrying amount of these instruments due to their short maturity. The fair value of long-term debt is based on publicly quoted market values.

Note 25 **COMMITMENTS AND CONTINGENT LIABILITIES**

Commitments	2007	2008	2009	2010	2011	Thereafter	Total
Transportation agreements	\$ 215	\$ 213	\$ 145	\$ 129	\$ 109	\$ 930	\$ 1,741
Exploration work commitments	88	18	18	7	1	-	132
Operating leases	492	140	106	99	75	237	1,149
	\$ 795	\$ 371	\$ 269	\$ 235	\$ 185	\$ 1,167	\$ 3,022

**Contingent Liabilities**

The Company is involved in litigation and claims in the normal course of operations. In addition, the Company may provide indemnifications, in the normal course of operations, that are often standard contractual terms to counterparties in certain transactions, such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents the Company from making a reasonable estimate of the maximum potential amounts that may be required to be paid. Management is of the opinion that any resulting settlements relating to the litigation matters or indemnifications would not materially affect the financial position or results of operations of the Company.

Note 26 **VARIABLE INTEREST ENTITIES**

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

Note 27 **GENERALLY ACCEPTED ACCOUNTING PRINCIPLES IN THE UNITED STATES**

The application of United States GAAP would have the following effects on earnings as reported:

	Notes	2006	2005	2004
Net earnings from continuing operations, as reported in the Consolidated Statement of Earnings				
		\$ 1,588	\$ 1,693	\$ 1,698
Adjustments, before income taxes				
Accounting for income taxes	(a)	8	117	(27)
Capitalization of interest and related amortization	(b)	47	46	8
Stock-based compensation	(g)	(24)	-	-
Other		-	1	1
Income taxes on above items		(10)	(15)	9
Net earnings from continuing operations, as adjusted before cumulative effect of change in accounting policy				
		1,609	1,842	1,689
Net earnings from discontinued operations				
		152	98	59
Net earnings, as adjusted before cumulative effect of change in accounting policy				
		1,761	1,940	1,748
Cumulative effect of change in accounting policy, net of income taxes				
	(g)	(14)	-	-
Net earnings, as adjusted				
		\$ 1,747	\$ 1,940	\$ 1,748
Earnings from continuing operations, as adjusted before cumulative effect of change in accounting policy per share				
Basic				
		\$ 3.19	\$ 3.55	\$ 3.19
Diluted				
		\$ 3.16	\$ 3.51	\$ 3.15
Earnings, as adjusted before cumulative effect of change in accounting policy per share				
Basic				
		\$ 3.49	\$ 3.74	\$ 3.30
Diluted				
		\$ 3.45	\$ 3.69	\$ 3.26
Earnings, as adjusted per share				
Basic				
		\$ 3.47	\$ 3.74	\$ 3.30
Diluted				
		\$ 3.43	\$ 3.69	\$ 3.26
Comprehensive income, net of tax				
Net earnings, as adjusted				
		\$ 1,747	\$ 1,940	\$ 1,748
Unrealized gain (loss) on financial derivatives	(d, f)	-	-	(5)
Change in minimum pension liability	(e, f)	42	(65)	(36)
Change in foreign currency translation adjustment	(f)	369	(588)	(49)
		\$ 2,158	\$ 1,287	\$ 1,658

The application of United States GAAP would have the following effects on the Consolidated Balance Sheet as reported:

	Notes	December 31, 2006		December 31, 2005	
		As Reported	United States GAAP	As Reported	United States GAAP
Current assets		\$ 2,826	\$ 2,826	\$ 2,934	\$ 2,934
Current assets – discontinued operations		–	–	237	237
Property, plant and equipment, net	(a, b)	18,577	19,209	15,921	16,513
Goodwill	(a)	801	780	737	716
Deferred charges and other assets	(e)	442	314	415	415
Assets of discontinued operations		–	–	411	411
Current liabilities	(g)	3,348	3,375	2,984	2,984
Current liabilities – discontinued operations		–	–	102	102
Long-term debt		2,887	2,887	2,906	2,906
Other liabilities	(e, g)	1,826	2,200	1,888	2,229
Asset retirement obligations		1,170	1,170	882	882
Future income taxes	(b, e, g)	2,974	2,977	2,405	2,469
Common shares		1,366	1,366	1,362	1,362
Contributed surplus	(c)	469	1,591	1,422	2,544
Retained earnings		8,557	7,831	7,018	6,285
Foreign currency translation adjustment	(f)	49	–	(314)	–
Accumulated other comprehensive income (loss)	(e, f)	\$ –	\$ (268)	\$ –	\$ (537)

The Company's Consolidated Financial Statements have been prepared in accordance with Canadian GAAP, which differ in some respects from those applicable in the United States. The following are the significant differences in accounting principles as they pertain to the accompanying Consolidated Financial Statements:

#### (a) Income Taxes

The liability method followed by the Company differs from United States GAAP due to the application of transitional provisions upon adoption and the use of substantively enacted versus enacted tax rates.

#### (b) Interest Capitalization

United States GAAP requires that interest be capitalized as part of the cost of certain assets while they are being prepared for their intended use. The Company capitalizes interest attributable to the construction of major new facilities under both Canadian and United States GAAP, but uses different capitalization methodologies under each.

#### (c) Contributed Surplus

In prior years, the Company transferred amounts from contributed surplus to the accumulated deficit. Under United States GAAP, these transfers are not permitted.

#### (d) Derivative Instruments and Hedging

United States GAAP requires that changes in the fair value of cash flow hedges be included in other comprehensive income. Under Canadian GAAP, these amounts are recorded in earnings only at the time of settlement.

**(e) Pensions and Other Post-Retirement Benefits**

The Company has adopted Statement of Financial Accounting Standard (SFAS) 158 – *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment to SFAS 87, 88, 106, 132(R)*, for United States GAAP for the year ended December 31, 2006. This Statement requires an employer to recognize in its statement of financial position the overfunded or underfunded status of a defined benefit post-retirement plan measured as the difference between the fair value of plan assets and the benefit obligation. The Statement also requires that changes, that would not otherwise be required to be included in period expenses, be recorded initially in other comprehensive income. The Statement has been applied prospectively, with no adjustment to prior periods. As a result, deferred charges and other assets decreased by \$128 million, other liabilities increased by \$94 million and accumulated other comprehensive income decreased by \$142 million, net of taxes of \$80 million.

Prior to the adoption of SFAS 158, United States GAAP required that a minimum liability be recorded for underfunded pension plans. The change in the liability, representing the excess of unfunded accumulated benefit obligations over previously unrecognized prior service costs, net of any tax benefits, was recognized in other comprehensive income.

**(f) Comprehensive Income**

United States GAAP uses the concept of comprehensive income, which includes net earnings and other comprehensive income. The concept of comprehensive income does not yet exist under Canadian GAAP. Other comprehensive income represents the change in equity during the period from transactions and other events from non-owner sources and includes such items as changes in the fair value of cash flow hedges, minimum pension liability adjustments and certain foreign currency translation adjustments.

**(g) Stock-Based Compensation**

The Company has adopted Statement of Financial Accounting Standard (SFAS) 123(R) *Share-Based Payment* for United States GAAP for the year ended December 31, 2006. This Statement requires compensation costs related to share-based awards classified as liabilities to be recognized as an expense at fair value with re-measurement to fair value each period. Under Canadian GAAP, the Company recognizes compensation cost for stock options, which provide the holder the right to exercise the stock option or surrender the option for cash payment based on the intrinsic value at each period end. This Statement was applied using the modified-prospective basis with no adjustment to prior periods. As a result, current liabilities increased by \$27 million, other liabilities increased by \$19 million and retained earnings decreased by \$29 million, net of taxes of \$17 million.

Note 28 **RECENT ACCOUNTING PRONOUNCEMENTS**

**Canadian**

*Convergence of Canadian GAAP with International Financial Reporting Standards*

In 2006, Canada's Accounting Standards Board (AcSB) ratified a strategic plan that will result in Canadian GAAP, as used by public companies, being converged with International Financial Reporting Standards over a transitional period. The AcSB is expected to develop and publish a detailed implementation plan, with a transition period expected to be approximately five years. This convergence initiative is in its early stages as of the date of these annual Consolidated Financial Statements and the Company has the option to adopt United States GAAP at any time prior to the expected conversion date. Accordingly, it would be premature to assess the impact of the initiative, if any, on the Company at this time.

*Financial Instruments, Comprehensive Income and Hedges*

The AcSB has issued five new accounting standards relating to the recognition, measurement, disclosure and presentation of financial instruments. The new standards comprise five handbook sections:

**CICA Section 3855 – *Financial Instruments – Recognition and Measurement***

This standard establishes the criteria for recognizing and measuring financial assets, financial liabilities and non-financial derivatives. It also specifies how financial instrument gains and losses are to be presented. Financial liabilities will be classified as either held-for-trading or other. Held-for-trading instruments will be recorded at fair value with realized and unrealized gains and losses reported in net income. Other instruments will be accounted for at amortized cost with gains and losses reported in net income in the period that the liability is derecognized.

Derivatives will be classified as held-for-trading unless designated as hedging instruments. All derivatives, including embedded derivatives that must be separately accounted for, will be recorded at fair value on the balance sheet. For derivatives that hedge the changes in fair value of an asset or liability, changes in the derivatives' fair value will be reported in net income and be substantially offset by changes in the fair value of the hedged asset or liability attributable to the risk being hedged. For derivatives that hedge variability in cash flows, the effective portion of the changes in the derivatives' fair value will be initially recognized in other comprehensive income and the ineffective portion will be recorded in net income. The amounts temporarily recorded in other comprehensive income will subsequently be reclassified to net income in the periods when net income is affected by the variability in the cash flows of the hedged item.

**CICA Section 3865 – *Hedges***

This standard provides optional alternative treatment to Section 3855 for entities which choose to designate qualifying transactions as hedges for accounting purposes. It will replace Accounting Guideline 13 (AcG 13) – *Hedging Relationships*, and build on Section 1651 – *Foreign Currency Translation*, by specifying how hedge accounting is applied and what disclosures are necessary when it is applied. Retroactive application of this section is not permitted.

**CICA Section 1530 – *Comprehensive Income***

This standard introduces a new requirement to temporarily present certain gains and losses as part of a new earnings measurement called comprehensive income.

**CICA Section 3862 – *Financial Instruments – Disclosures***

This standard requires entities to provide disclosures in their financial statements that enable users to evaluate the significance of financial instruments to the entity's financial position and performance. It also requires that entities disclose the nature and extent of risks arising from financial instruments and how the entity manages those risks.

**CICA Section 3863 – *Financial Instruments – Presentation***

This standard establishes standards for presentation of financial instruments and non-financial derivatives and deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset.

CICA sections 3855, 3865 and 1530 are effective for annual and interim periods in fiscal years beginning on or after October 1, 2006. A presentation reclassification of amounts previously recorded in "Foreign currency translation adjustment" to "Accumulated other comprehensive income" will be made upon adoption of Section 1530. The Company does not expect there to be any other material impact on the Consolidated Financial Statements upon adoption of the new standards.

CICA sections 3862 and 3863 are effective for annual and interim periods beginning on or after October 1, 2007.

### *Accounting Changes*

The AcSB issued CICA Section 1506, *Accounting Changes*. The standard prescribes the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies and estimates, and correction of errors. The standard requires the retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impractical to determine either the period-specific effects or the cumulative effect of the change. Application is on a prospective basis and is effective for changes in accounting policies and estimates and correction of errors made in fiscal years beginning on or after January 1, 2007.

### *Variable Interest Entities*

The Emerging Issues Committee (EIC) issued EIC Abstract 163 – *Determining the Variability to be Considered in Applying AcG 15*. This Abstract, which is harmonized with the equivalent United States FASB Staff Position (FSP) FIN 46(R) – 6 – *Determining the Variability to be Considered in Applying FASB Interpretation No. 46(R)*, provides guidance on how an enterprise should determine the variability to be considered in applying *AcG 15 – Consolidation of Variable Interest Entities*. The Abstract is to be applied prospectively to all entities with which an enterprise first becomes involved and to all entities previously required to be analyzed under *AcG 15* when a reconsideration event has occurred beginning the first day of the first reporting period beginning on or after January 1, 2007.

### *Stripping Costs Incurred During Production*

The EIC issued EIC Abstract 160 – *Stripping Costs Incurred in the Production Phase of a Mining Operation*. The Abstract provides that stripping costs incurred during production should be accounted for as a variable production cost and included in the costs of inventory extracted during the period unless the stripping activity represents a betterment to the mineral property. In that instance, the portion considered to be a betterment would be capitalized as part of the cost of the mine and amortized using the unit of production method over the reserves that directly benefit from the specific stripping activity. The Abstract may be applied prospectively or retrospectively and is effective for all stripping costs incurred in fiscal periods beginning after July 1, 2006. The Company does not expect there to be any material impact on the Consolidated Financial Statements upon adoption of the Abstract.

## **United States**

### *Fair Value Measurements*

The FASB issued SFAS 157 – *Fair Value Measurements*. The Statement defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. This Statement applies under other accounting pronouncements that require or permit fair value measurements. The Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company is in the process of assessing the impact of this Statement.

### *Accounting for Servicing of Financial Assets*

The FASB issued SFAS 156 – *Accounting for Servicing of Financial Assets – an amendment of FASB Statement No. 140*. This Statement requires that an entity separately recognize a servicing asset or a servicing liability when it undertakes an obligation to service a financial asset under a servicing contract in certain situations. Such servicing assets or servicing liabilities are required to be initially measured at fair value. The Statement is effective for fiscal years beginning after September 15, 2006. The Company does not expect there to be a material impact on the Consolidated Financial Statements upon adoption of the Statement.

*Accounting for Certain Hybrid Financial Instruments*

The FASB issued SFAS 155 – *Accounting for Certain Hybrid Financial Instruments*. This Statement amends SFAS 133 on derivatives and hedging and SFAS 140 on transfers and servicing of financial assets and extinguishments of liabilities. The Statement provides a fair value measurement option for certain hybrid financial instruments containing an embedded derivative that would otherwise require bifurcation. The Statement is effective for all instruments acquired, issued or subject to a re-measurement event occurring in years beginning after September 15, 2006. The Company does not expect there to be a material impact on the Consolidated Financial Statements upon adoption of the Statement.

*Accounting for Uncertainty in Income Taxes*

The FASB issued FASB Interpretation No. 48 – *Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109*. The Interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The Interpretation requires the Company to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. Only tax positions that meet the more-likely-than-not recognition threshold are measured to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. The Interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Interpretation is effective for fiscal periods beginning after December 15, 2006 and the provisions of the Interpretation must be applied to all tax positions upon initial adoption. The Company is in the process of assessing the impact of this Interpretation.

*Sales Taxes*

The Emerging Issues Task Force (EITF) issued EITF *Abstract 06-3 – How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statement (That is Gross versus Net Presentation)*. The Abstract allows an entity to adopt a policy of presenting taxes that are externally imposed on revenue producing transactions on either a gross or net basis, but requires that the entity disclose its accounting policy regarding presentation of such taxes in the notes to the financial statements. The Abstract is effective for fiscal periods beginning after December 15, 2006 and retrospective application is required. The Company does not expect there to be any material impact on the Consolidated Financial Statements upon adoption of the Abstract.

# Reserves of Crude Oil, Natural Gas Liquids, Natural Gas, Bitumen and Synthetic Crude Oil – Before Royalties

The following table shows, for the years indicated, Petro-Canada's estimates of proved reserves, before royalties: TABLE 1 – Oil and Gas Activities; TABLE 2 – Oil Sands Mining; and TABLE 3 – Total of Oil and Gas Activities and Oil Sands Mining.

Proved Reserves Before Royalties  <i>(Crude oil and equivalents in MMbbls; Natural gas in Bcf)</i>	TABLE 1 Oil and Gas Activities <sup>1, 2, 3, 4, 5</sup>							
	International							
	NORTHWEST EUROPE <sup>4</sup>		NORTH AFRICA/ NEAR EAST <sup>7, 8, 9, 10, 11, 14</sup>		NORTHERN LATIN AMERICA <sup>7, 12</sup>		SUBTOTAL	
	Crude oil & NGL	Natural gas	Crude oil & NGL	Natural gas	Natural gas	Crude oil & NGL	Natural gas	
<b>Beginning of year 2005</b>	<b>148</b>	<b>131</b>	<b>210</b>	<b>39</b>	<b>265</b>	<b>358</b>	<b>435</b>	
Revisions of previous estimates <sup>14</sup>	2	4	29	(14)	–	31	(10)	
Sale of reserves in place	–	–	–	–	–	–	–	
Purchase of reserves in place	5	4	–	–	–	5	4	
Discoveries, extensions and improved recovery	–	–	3	–	–	3	–	
Production net	(12)	(24)	(42)	(9)	(26)	(54)	(59)	
<b>End of year 2005</b>	<b>143</b>	<b>115</b>	<b>200</b>	<b>16</b>	<b>239</b>	<b>343</b>	<b>370</b>	
Revisions of previous estimates <sup>14</sup>	13	(6)	(2)	–	(1)	11	(7)	
Sale of reserves in place	–	(2)	(46)	(15)	–	(46)	(17)	
Purchase of reserves in place	–	–	–	–	–	–	–	
Discoveries, extensions and improved recovery	–	–	–	–	–	–	–	
Production net	(12)	(23)	(18)	–	(23)	(30)	(46)	
<b>End of year 2006</b>	<b>144</b>	<b>84</b>	<b>134</b>	<b>1</b>	<b>215</b>	<b>278</b>	<b>300</b>	
<b>Proved Undeveloped Reserves<sup>15</sup></b>								
<b>Beginning of year 2005</b>	<b>101</b>	<b>14</b>	<b>21</b>	<b>–</b>	<b>178</b>	<b>122</b>	<b>192</b>	
<b>End of year 2005</b>	<b>95</b>	<b>14</b>	<b>22</b>	<b>–</b>	<b>178</b>	<b>117</b>	<b>192</b>	
<b>End of year 2006</b>	<b>42</b>	<b>3</b>	<b>3</b>	<b>–</b>	<b>138</b>	<b>45</b>	<b>141</b>	

1 In order to harmonize its oil and gas disclosure in both Canada and the U.S., Petro-Canada applied for, and received, certain exemptions to reserves disclosure requirements as set out in NI 51-101. These exemptions permit Petro-Canada to use its own staff of qualified reserves evaluators to prepare the Company's reserves estimates and to use U.S. SEC and FASB standards when preparing and reporting reserves. Such reserves information may differ from reserves information prepared in accordance with Canadian disclosure standards under NI 51-101. These differences relate to the SEC requirement for disclosure only of proved reserves calculated at constant year-end prices and costs while NI 51-101 requires disclosure of proved reserves at constant prices and costs, and proved plus probable reserves at forecast prices and costs. Also, the definition of proved reserves differs between SEC and NI 51-101 requirements. However, this difference should not be material. The Canadian Oil and Gas Evaluation Handbook (the source document for reserves definitions under NI 51-101) supports this view.

2 Petro-Canada employs the services of independent third-party evaluators/auditors to assess its reserves policies, practices and procedures and its reserves estimates.

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

4 Proved reserves are the estimated quantities of crude oil, natural gas and NGL, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and

operating conditions. Proved developed reserves are those proved reserves that are expected to be recovered from existing wells or facilities. Proved undeveloped reserves are proved reserves, which are not recoverable from existing wells or facilities, but which are expected to be recovered through additional development drilling or through the upgrading of existing or additional new facilities.

5 Unproved reserves are based on geological and/or engineering data similar to that used in estimates of proved reserves, but technical, contractual, economic or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.

6 Reserves in Northwest Europe are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in the Netherlands.

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

8 In Petro-Canada's Production-Sharing Contracts (PSCs), after royalty proved reserves have been determined using the economic interest method and include the Company's share of future cost recovery and profit oil after foreign governments' royalty interest, and include reserves relating to income tax payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa) since the bbls necessary to achieve cost recovery change with the prevailing oil prices.

9 Reserves in Syria are held under PSCs with the Syrian government and are calculated as per footnote 8.

**TABLE 1**  
Oil and Gas Activities<sup>1,2,3,4,5</sup>

**TABLE 2**  
Oil Sands  
Mining<sup>1,2,3,4,5</sup>

**TABLE 3**  
Total Oil and Gas  
Activities and  
Oil Sands Mining

North America											SYNCRUDE MINING OPERATION <sup>11</sup>	TOTAL
NORTH AMERICAN NATURAL GAS												
WESTERN CANADA		U.S. ROCKIES		EAST COAST	OIL SANDS	SUBTOTAL		TOTAL				
Crude oil & NGL	Natural gas	Crude oil & NGL	Natural gas	Crude oil & NGL	Bitumen	Crude oil, NGL & bitumen	Natural gas	Crude oil, NGL & bitumen	Natural gas	Synthetic crude oil <sup>17</sup>	Crude oil & equivalents	
<b>38</b>	<b>1,950</b>	<b>6</b>	<b>88</b>	<b>68</b>	-	<b>112</b>	<b>2,038</b>	<b>470</b>	<b>2,473</b>	<b>331</b>	<b>801</b>	
5	(36)	2	22	68	8	83	(14)	114	(24)	20	134	
-	-	-	-	-	-	-	-	-	-	-	-	
-	-	-	-	-	-	-	-	5	4	-	5	
4	44	-	-	23	-	27	44	30	44	-	30	
(5)	(229)	(1)	(14)	(27)	(8)	(41)	(243)	(95)	(302)	(9)	(104)	
<b>42</b>	<b>1,729</b>	<b>7</b>	<b>96</b>	<b>132</b>	-	<b>181</b>	<b>1,825</b>	<b>524</b>	<b>2,195</b>	<b>342</b>	<b>866</b>	
1	(47)	2	64	18	165	186	17	197	10	14	211	
-	(1)	-	-	-	-	-	(1)	(46)	(18)	-	(46)	
-	1	-	-	-	-	-	1	-	1	-	-	
-	27	-	-	-	-	-	27	-	27	-	-	
(4)	(209)	(1)	(15)	(27)	(8)	(40)	(224)	(70)	(270)	(11)	(81)	
<b>39</b>	<b>1,500</b>	<b>8</b>	<b>145</b>	<b>123</b>	<b>157</b>	<b>327</b>	<b>1,645</b>	<b>605</b>	<b>1,945</b>	<b>345</b>	<b>950</b>	
<b>1</b>	<b>82</b>	<b>2</b>	<b>24</b>	<b>19</b>	-	<b>22</b>	<b>106</b>	<b>144</b>	<b>298</b>	<b>189</b>	<b>333</b>	
<b>1</b>	<b>132</b>	<b>3</b>	<b>30</b>	<b>43</b>	-	<b>47</b>	<b>162</b>	<b>164</b>	<b>354</b>	<b>209</b>	<b>373</b>	
-	<b>56</b>	<b>4</b>	<b>36</b>	<b>33</b>	<b>129</b>	<b>166</b>	<b>92</b>	<b>211</b>	<b>233</b>	<b>219</b>	<b>430</b>	

10 With the exception of the En Naga field, reserves in Libya are held under a concession and are subject to a royalty and tax regime. The En Naga field is held under a PSC with the Libyan government, with reserves being calculated as per footnote 8.

11 The volume of oil and gas reserves before royalties reported above held under PSCs in the North Africa/Near East region at the end of 2006 was 10 MMbbls of crude oil and NGL and zero Bcf of natural gas. At year-end 2005, the volume was 59 MMbbls of crude oil and NGL and 15 Bcf of natural gas. The after royalty reserves volumes were: year-end 2006 – 7 MMbbls of crude oil and NGL and zero Bcf of natural gas, and year-end 2005 – 21 MMbbls of crude oil and NGL and 5 Bcf of natural gas. Reserves information for 2005 includes the Syrian producing assets sold in 2006.

12 Natural gas reserves in Trinidad and Tobago are held under a PSC with the applicable government and are calculated as per footnote 8. The volume of proved natural gas reserves before royalties reported above held under PSCs in Trinidad and Tobago at the end of 2006 was 215 Bcf. At year-end 2005, the volume was 239 Bcf. The after royalty reserves volumes were: year-end 2006 – 189 Bcf, and year-end 2005 – 203 Bcf.

13 U.S. SEC regulations do not define proved reserves of synthetic crude oil from oil sands mining operations as an oil and gas activity. These reserves are classified as a mining activity and are estimated in accordance with SEC Industry Guide 7. Petro-Canada views these reserves as an integral part of the Company's business. Proved reserves of synthetic crude oil are based on high geological certainty and

application of proven or piloted technology. For proved reserves, drill-hole spacing is less than 500 metres and appropriate co-owner and regulatory approvals are in place. Syncrude proved oil sands mining reserves have been determined using SEC year-end prices in the economics.

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

15 Proved undeveloped crude oil and NGL proved reserves in Table 1 represent approximately 35% of Petro-Canada's total crude oil and NGL proved reserves. The vast majority of these oil and NGL reserves are associated with large development projects currently producing or under active development, including Buzzard, MacKay River, White Rose, Terra Nova and Hibernia. Proved undeveloped gas reserves represent approximately 12% of total proved natural gas reserves. These reserves typically will be developed through tie-in of existing wells, drilling of additional wells or addition of compression facilities. Fifty-nine per cent of the proved undeveloped gas reserves are associated with the currently producing NCMA-1 development in Trinidad and Tobago. Generally, the Company plans to develop proved undeveloped natural gas reserves in the next few years.

16 The Company closed the sale of its Syrian producing assets on January 31, 2006.

17 For internal management purposes, we view the oil sands mining reserves as part of the Company's total exploration and production operations.

# Reserves of Crude Oil, Natural Gas Liquids, Natural Gas, Bitumen and Synthetic Crude Oil – After Royalties *continued*

The following table shows, for the years indicated, Petro-Canada's estimates of proved reserves, after royalties: TABLE 1 – Oil and Gas Activities; TABLE 2 – Oil Sands Mining; and TABLE 3 – Total of Oil and Gas Activities and Oil Sands Mining.

Proved Reserves After Royalties  <i>(Crude oil and equivalents in MMbbls; Natural gas in Bcf)</i>	TABLE 1 Oil and Gas Activities <sup>1, 2, 3, 4, 5</sup>							
	International							
	NORTHWEST EUROPE <sup>4</sup>		NORTH AFRICA/ NEAR EAST <sup>7, 8, 9, 10, 11, 14</sup>		NORTHERN LATIN AMERICA <sup>7, 12</sup>		SUBTOTAL	
	Crude oil & NGL	Natural gas	Crude oil & NGL	Natural gas	Natural gas	Crude oil & NGL	Natural gas	
<b>Beginning of year 2005</b>	<b>148</b>	<b>131</b>	<b>144</b>	<b>13</b>	<b>225</b>	<b>292</b>	<b>369</b>	
Revisions of previous estimates <sup>14</sup>	1	5	28	(6)	(1)	29	(2)	
Sale of reserves in place	-	-	-	-	-	-	-	
Purchase of reserves in place	5	3	-	-	-	5	3	
Discoveries, extensions and improved recovery	-	-	2	-	-	2	-	
Production net	(12)	(24)	(22)	(2)	(21)	(34)	(47)	
<b>End of year 2005</b>	<b>142</b>	<b>115</b>	<b>152</b>	<b>5</b>	<b>203</b>	<b>294</b>	<b>323</b>	
Revisions of previous estimates <sup>14</sup>	13	(6)	28	10	(2)	41	2	
Sale of reserves in place	-	(2)	(42)	(15)	-	(42)	(17)	
Purchase of reserves in place	-	-	-	-	-	-	-	
Discoveries, extensions and improved recovery	-	-	-	-	-	-	-	
Production net	(12)	(23)	(16)	-	(12)	(28)	(35)	
<b>End of year 2006</b>	<b>143</b>	<b>84</b>	<b>122</b>	<b>-</b>	<b>189</b>	<b>265</b>	<b>273</b>	
<b>Proved Undeveloped Reserves<sup>15</sup></b>								
<b>Beginning of year 2005</b>	<b>101</b>	<b>14</b>	<b>14</b>	<b>-</b>	<b>151</b>	<b>115</b>	<b>165</b>	
<b>End of year 2005</b>	<b>95</b>	<b>14</b>	<b>15</b>	<b>-</b>	<b>151</b>	<b>110</b>	<b>165</b>	
<b>End of year 2006</b>	<b>42</b>	<b>4</b>	<b>2</b>	<b>-</b>	<b>121</b>	<b>44</b>	<b>125</b>	

1 In order to harmonize its oil and gas disclosure in both Canada and the U.S., Petro-Canada applied for, and received, certain exemptions to reserves disclosure requirements as set out in NI 51-101. These exemptions permit Petro-Canada to use its own staff of qualified reserves evaluators to prepare the Company's reserves estimates and to use U.S. SEC and FASB standards when preparing and reporting reserves. Such reserves information may differ from reserves information prepared in accordance with Canadian disclosure standards under NI 51-101. These differences relate to the SEC requirement for disclosure only of proved reserves calculated at constant year-end prices and costs while NI 51-101 requires disclosure of proved reserves at constant prices and costs, and proved plus probable reserves at forecast prices and costs. Also, the definition of proved reserves differs between SEC and NI 51-101 requirements. However, this difference should not be material. The Canadian Oil and Gas Evaluation Handbook (the source document for reserves definitions under NI 51-101) supports this view.

2 Petro-Canada employs the services of independent third-party evaluators/auditors to assess its reserves policies, practices and procedures and its reserves estimates.

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

4 Proved reserves are the estimated quantities of crude oil, natural gas and NGL, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and

operating conditions. Proved developed reserves are those proved reserves that are expected to be recovered from existing wells or facilities. Proved undeveloped reserves are proved reserves, which are not recoverable from existing wells or facilities, but which are expected to be recovered through additional development drilling or through the upgrading of existing or additional new facilities.

5 Unproved reserves are based on geological and/or engineering data similar to that used in estimates of proved reserves, but technical, contractual, economic or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.

6 Reserves in Northwest Europe are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in the Netherlands.

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

8 In Petro-Canada's Production-Sharing Contracts (PSCs), after royalty proved reserves have been determined using the economic interest method and include the Company's share of future cost recovery and profit oil after foreign governments' royalty interest, and include reserves relating to income tax payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa) since the bbls necessary to achieve cost recovery change with the prevailing oil prices.

9 Reserves in Syria are held under PSCs with the Syrian government and are calculated as per footnote 8.

<b>TABLE 1</b> Oil and Gas Activities <sup>1,2,3,4,5</sup>											<b>TABLE 2</b> Oil Sands Mining <sup>1,2,3,4,5</sup>	<b>TABLE 3</b> Total Oil and Gas Activities and Oil Sands Mining
<b>North America</b>											SYNCRUDE MINING OPERATION <sup>11</sup>	TOTAL
NORTH AMERICAN NATURAL GAS												
WESTERN CANADA		U.S. ROCKIES		EAST COAST	OIL SANDS	SUBTOTAL		TOTAL				
Crude oil & NGL	Natural gas	Crude oil & NGL	Natural gas	Crude oil & NGL	Bitumen	Crude oil, NGL & bitumen	Natural gas	Crude oil, NGL & bitumen	Natural gas	Synthetic crude oil <sup>17</sup>	Crude oil & equivalents	
<b>30</b>	<b>1,508</b>	<b>4</b>	<b>73</b>	<b>61</b>	-	<b>95</b>	<b>1,581</b>	<b>387</b>	<b>1,950</b>	<b>287</b>	<b>674</b>	
5	(28)	7	18	57	8	77	(10)	106	(12)	9	115	
-	-	-	-	-	-	-	-	-	-	-	-	
-	-	-	-	-	-	-	-	5	3	-	5	
3	34	-	-	20	-	23	34	25	34	-	25	
(4)	(175)	(6)	(12)	(25)	(8)	(43)	(187)	(77)	(234)	(9)	(86)	
<b>34</b>	<b>1,339</b>	<b>5</b>	<b>79</b>	<b>113</b>	-	<b>152</b>	<b>1,418</b>	<b>446</b>	<b>1,741</b>	<b>287</b>	<b>733</b>	
1	(43)	2	55	10	159	172	12	213	14	12	225	
-	(1)	-	-	-	-	-	(1)	(42)	(18)	-	(42)	
-	1	-	-	-	-	-	1	-	1	-	-	
-	21	-	-	-	-	-	21	-	21	-	-	
(3)	(166)	(1)	(12)	(25)	(8)	(37)	(178)	(65)	(213)	(10)	(75)	
<b>32</b>	<b>1,151</b>	<b>6</b>	<b>122</b>	<b>98</b>	<b>151</b>	<b>287</b>	<b>1,273</b>	<b>552</b>	<b>1,546</b>	<b>289</b>	<b>841</b>	
<b>1</b>	<b>65</b>	<b>2</b>	<b>20</b>	<b>16</b>	-	<b>19</b>	<b>85</b>	<b>134</b>	<b>250</b>	<b>161</b>	<b>295</b>	
<b>1</b>	<b>99</b>	<b>3</b>	<b>25</b>	<b>33</b>	-	<b>37</b>	<b>124</b>	<b>147</b>	<b>289</b>	<b>173</b>	<b>320</b>	
-	<b>42</b>	<b>4</b>	<b>30</b>	<b>24</b>	<b>124</b>	<b>152</b>	<b>72</b>	<b>196</b>	<b>197</b>	<b>182</b>	<b>378</b>	

10 With the exception of the En Naga field, reserves in Libya are held under a concession and are subject to a royalty and tax regime. The En Naga field is held under a PSC with the Libyan government, with reserves being calculated as per footnote 8.

11 The volume of oil and gas reserves before royalties reported above held under PSCs in the North Africa/Near East region at the end of 2006 was 10 MMbbls of crude oil and NGL and zero Bcf of natural gas. At year-end 2005, the volume was 59 MMbbls of crude oil and NGL and 15 Bcf of natural gas. The after royalty reserves volumes were: year-end 2006 – 7 MMbbls of crude oil and NGL and zero Bcf of natural gas, and year-end 2005 – 21 MMbbls of crude oil and NGL and 5 Bcf of natural gas. Reserves information for 2005 includes the Syrian producing assets sold in 2006.

12 Natural gas reserves in Trinidad and Tobago are held under a PSC with the applicable government and are calculated as per footnote 8. The volume of proved natural gas reserves before royalties reported above held under PSCs in Trinidad and Tobago at the end of 2006 was 215 Bcf. At year-end 2005, the volume was 239 Bcf. The after royalty reserves volumes were: year-end 2006 – 189 Bcf, and year-end 2005 – 203 Bcf.

13 U.S. SEC regulations do not define proved reserves of synthetic crude oil from oil sands mining operations as an oil and gas activity. These reserves are classified as a mining activity and are estimated in accordance with SEC Industry Guide 7. Petro-Canada views these reserves as an integral part of the Company's business. Proved reserves of synthetic crude oil are based on high geological certainty and

application of proven or piloted technology. For proved reserves, drill-hole spacing is less than 500 metres and appropriate co-owner and regulatory approvals are in place. Syncrude proved oil sands mining reserves have been determined using SEC year-end prices in the economics.

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

15 Proved undeveloped crude oil and NGL proved reserves in Table 1 represent approximately 35% of Petro-Canada's total crude oil and NGL proved reserves. The vast majority of these oil and NGL reserves are associated with large development projects currently producing or under active development, including Buzzard, MacKay River, White Rose, Terra Nova and Hibernia. Proved undeveloped gas reserves represent approximately 12% of total proved natural gas reserves. These reserves typically will be developed through tie-in of existing wells, drilling of additional wells or addition of compression facilities. Fifty-nine per cent of the proved undeveloped gas reserves are associated with the currently producing NCMA-1 development in Trinidad and Tobago. Generally, the Company plans to develop proved undeveloped natural gas reserves in the next few years.

16 The Company closed the sale of its Syrian producing assets on January 31, 2006.

17 For internal management purposes, we view the oil sands mining reserves as part of the Company's total exploration and production operations.

# Quarterly Financial and Stock Trading Information

(unaudited, stated in millions of Canadian dollars, unless otherwise indicated)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter 2006	First Quarter	Second Quarter	Third Quarter	Fourth Quarter 2005
<b>Revenue</b>								
Operating	\$ 4,415	\$ 4,836	\$ 5,065	\$ 4,595	\$ 3,767	\$ 4,174	\$ 4,839	\$ 4,805
Investment and other income (expense)	(227)	(106)	136	(45)	(492)	(229)	(118)	33
	4,188	4,730	5,201	4,550	3,275	3,945	4,721	4,838
<b>Expenses</b>								
Crude oil and product purchases	2,100	2,578	2,745	2,226	1,852	2,096	2,469	2,429
Operating, marketing and general	821	782	742	835	669	737	750	806
Exploration	97	78	57	107	82	58	54	77
Depreciation, depletion and amortization	335	312	311	407	302	306	329	285
Unrealized (gain) loss on translation of foreign currency denominated long-term debt	2	(73)	1	69	5	(10)	(90)	7
Interest	45	42	41	37	34	39	39	52
	3,400	3,719	3,897	3,681	2,944	3,226	3,551	3,656
<b>Earnings from continuing operations</b>								
before income taxes	788	1,011	1,304	869	331	719	1,170	1,182
Provision for income taxes	734	539	626	485	221	397	577	514
<b>Net earnings from continuing operations</b>								
	54	472	678	384	110	322	593	668
<b>Net earnings from discontinued operations</b>								
	152	-	-	-	8	23	21	46
<b>Net earnings</b>								
	\$ 206	\$ 472	\$ 678	\$ 384	\$ 118	\$ 345	\$ 614	\$ 714
<b>Cash flow from continuing operating activities before changes in non-cash working capital</b>								
	\$ 857	\$ 754	\$ 1,085	\$ 991	\$ 801	\$ 869	\$ 1,001	\$ 1,116
<b>Earnings</b>								
<b>Upstream</b>								
North American Natural Gas	\$ 139	\$ 97	\$ 75	\$ 91	\$ 103	\$ 117	\$ 156	\$ 284
East Coast Oil	229	254	190	261	169	208	218	180
Oil Sands	(19)	101	108	55	(19)	34	82	15
International	(132)	61	60	33	105	93	104	151
Downstream	73	136	176	78	113	80	98	107
Shared Services	(88)	(117)	(12)	(47)	(44)	(56)	(61)	(89)
<b>Operating earnings from continuing operations</b>								
	202	532	597	471	427	476	597	648
Foreign currency translation gain (loss)	(1)	61	(1)	(58)	(4)	8	74	(5)
<b>Unrealized gain (loss) on Buzzard derivative contracts</b>								
	(149)	(137)	79	(33)	(313)	(171)	(85)	7
Gain on sale of assets	2	16	3	4	-	9	7	18
Discontinued operations	152	-	-	-	8	23	21	46
<b>Net earnings</b>								
	\$ 206	\$ 472	\$ 678	\$ 384	\$ 118	\$ 345	\$ 614	\$ 714

## Quarterly Financial and Stock Trading Information *continued*

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter 2006	First Quarter	Second Quarter	Third Quarter	Fourth Quarter 2005
<b>Share Information</b> <i>(dollars per share)</i>								
Earnings from continuing operations								
– basic	\$ 0.11	\$ 0.93	\$ 1.36	\$ 0.77	\$ 0.21	\$ 0.62	\$ 1.14	\$ 1.29
– diluted	0.10	0.92	1.34	0.76	0.21	0.61	1.13	1.28
Earnings								
– basic	0.40	0.93	1.36	0.77	0.23	0.66	1.19	1.38
– diluted	0.40	0.92	1.34	0.76	0.22	0.66	1.17	1.36
Cash flow from continuing operating activities before changes in non-cash working capital	1.67	1.49	2.17	1.99	1.54	1.67	1.93	2.16
Dividends	0.10	0.10	0.10	0.10	0.08	0.07	0.08	0.10
Toronto Stock Exchange								
Share price <sup>1</sup>								
– high	58.59	57.80	53.30	51.70	36.68	41.19	50.80	50.20
– low	48.00	46.11	42.38	41.91	29.51	33.65	40.33	40.13
– close <i>(end of period)</i>	\$ 55.38	\$ 52.96	\$ 45.01	\$ 47.75	\$ 35.13	\$ 39.88	\$ 48.66	\$ 46.65
Shares traded <i>(millions)</i>	140.3	124.2	111.1	108.7	143.6	122.9	139.9	169.6
New York Stock Exchange								
Share price <sup>2</sup>								
– high	51.08	51.11	48.24	45.48	30.40	33.51	43.47	43.03
– low	41.20	41.31	37.78	37.37	24.15	26.70	33.02	33.96
– close <i>(end of period)</i>	\$ 47.59	\$ 47.41	\$ 40.33	\$ 41.04	\$ 28.93	\$ 32.57	\$ 41.73	\$ 40.09
Shares traded <i>(millions)</i>	33.8	38.2	32.3	34.2	19.3	22.9	34.4	29.1

1 Per share amounts are quoted in Canadian dollars and represent the closing price.

2 Per share amounts are quoted in U.S. dollars and represent the closing price.

# Three-Year Financial and Operating Summary

(stated in millions of Canadian dollars, unless otherwise indicated)

	2006	2005	2004
<b>Consolidated</b>			
Revenue	\$ 18,669	\$ 16,779	\$ 13,958
Expenses	14,697	13,377	10,868
Provision for income taxes	2,384	1,709	1,392
Net earnings from continuing operations	1,588	1,693	1,698
Net earnings from discontinued operations	152	98	59
Net earnings	\$ 1,740	\$ 1,791	\$ 1,757
Cash flow from continuing operating activities before changes in non-cash working capital	3,687	3,787	3,425
Total assets	22,646	20,655	18,136
Average capital employed	12,868	11,860	10,533
Operating return on capital employed (%) <sup>1</sup>	15.0	19.8	18.8
Return on capital employed (%)	14.3	16.0	17.5
Debt	2,894	2,913	2,580
Debt-to-debt plus equity (%)	21.7	23.5	22.8
Debt-to-cash flow (times) <sup>2</sup>	0.8	0.8	0.8
Expenditures on property, plant and equipment and exploration from continuing operations	3,434	3,560	3,893
Employees	5,156	4,816	4,795
<b>Shareholders' Data</b>			
Weighted-average number of common shares outstanding (millions)	503.9	518.4	529.3
Weighted-average number of diluted common shares outstanding (millions)	509.9	525.4	536.2
Shares outstanding at year end (millions) <sup>3</sup>	497.5	515.1	520.0
Toronto Stock Exchange			
Share price (dollars) <sup>4</sup>			
- at year end	47.75	46.65	30.59
- range during the year	41.91-58.59	29.51-50.80	27.93-34.75
Shares traded (millions)	484.3	575.9	576.7
New York Stock Exchange			
Share price (dollars) <sup>5</sup>			
- at year end	41.04	40.09	25.51
- range during the year	37.37-51.11	24.15-43.47	20.89-28.55
Shares traded (millions)	138.5	105.7	58.8
Book value per share (dollars)	20.99	18.41	16.81

1 Operating earnings are earnings before gains or losses on foreign currency translation, disposal of assets and the unrealized loss on Buzzard derivative contracts.

2 From continuing operations.

3 On September 29, 2004, the Government of Canada completed its offering to the public of its entire remaining interest in Petro-Canada.

4 Per share amounts are quoted in Canadian dollars on a post-stock dividend basis, reflecting the stock dividend declared in July 2005, and represent the closing price.

5 Per share amounts are quoted in U.S. dollars and represent the closing price.

	2006	2005	2004
<b>North American Natural Gas</b>			
Operating earnings	\$ 402	\$ 660	\$ 500
Gain on sale of assets	3	14	-
Net earnings	\$ 405	\$ 674	\$ 500
Cash flow from operating activities before changes in non-cash working capital	739	1,193	882
Expenditures on property, plant and equipment and exploration	788	713	666
Daily production, net (before/after royalties)			
- crude oil and liquids (thousands of barrels - Mbbls)	14.2/10.8	14.7/11.2	15.3/11.4
- natural gas (MMcf)	616/489	668/512	695/530
Proved reserves (before/after royalties)			
- crude oil and liquids (MMbbls)	47/38	49/39	44/34
- natural gas (Bcf)	1,645/1,273	1,825/1,418	2,038/1,581
Oil and gas landholdings (gross/net) (millions of acres)	16.6/11.6	16.7/12.2	14.9/11.3
Wells drilled (gross/net)			
- oil	78/71	4/2	7/2
- natural gas	569/427	714/468	642/496
- dry	29/25	25/18	26/19
Total	676/523	743/488	675/517

## Three-Year Financial and Operating Summary *continued*

*(stated in millions of Canadian dollars, unless otherwise indicated)*

	2006	2005	2004
<b>East Coast Oil</b>			
Operating earnings and net earnings	<b>\$ 934</b>	\$ 775	\$ 771
Cash flow from operating activities before changes in non-cash working capital	<b>1,163</b>	1,062	993
Expenditures on property, plant and equipment and exploration	<b>256</b>	314	275
Daily production, net <i>(before/after royalties)</i>			
– crude oil and liquids <i>(Mbbbls)</i>	<b>72.7/68.5</b>	75.3/69.6	78.2/75.1
Proved reserves <i>(before/after royalties)</i>			
– crude oil and liquids <i>(MMbbls)</i>	<b>123/98</b>	132/113	68/61
Oil and gas landholdings <i>(gross/net) (millions of acres)</i>	<b>2.1/0.7</b>	2.5/0.9	3.6/1.2
Wells drilled <i>(gross/net)</i>			
– oil	<b>13/4</b>	15/4	17/4
– dry	<b>0/0</b>	0/0	0/0
<b>Total</b>	<b>13/4</b>	15/4	17/4
<b>Oil Sands</b>			
Operating earnings	<b>\$ 245</b>	\$ 112	\$ 120
Gain on sale of assets	–	3	–
<b>Net earnings</b>	<b>\$ 245</b>	\$ 115	\$ 120
Cash flow from operating activities before changes in non-cash working capital	<b>497</b>	380	332
Expenditures on property, plant and equipment and exploration	<b>377</b>	772	397
Daily production, net <i>(before/after royalties)</i>			
– bitumen <i>(Mbbbls)</i>	<b>21.2/20.8</b>	21.3/21.1	16.6/16.5
– synthetic crude oil <i>(Mbbbls)</i>	<b>31.0/28.0</b>	25.7/25.4	28.6/28.3
Proved reserves <i>(before/after royalties)</i>			
– bitumen <i>(MMbbls)</i>	<b>157/151</b>	0/0	0/0
– synthetic crude oil <sup>1</sup> <i>(MMbbls)</i>	<b>345/289</b>	342/287	331/287
Oil and gas landholdings <i>(gross/net) (millions of acres)</i>	<b>0.8/0.5</b>	0.7/0.4	0.6/0.3
Wells drilled <i>(gross/net)</i>			
– oil sands – bitumen	<b>0/0</b>	46/46	0/0
– dry	<b>0/0</b>	0/0	0/0
<b>Total</b>	<b>0/0</b>	46/46	0/0
<b>International (from continuing operations)</b>			
Operating earnings	<b>\$ 22</b>	\$ 453	\$ 313
Gain on sale of assets	<b>12</b>	–	8
Unrealized loss on Buzzard derivative contracts	<b>(240)</b>	(562)	(205)
<b>Net earnings (loss)</b>	<b>\$ (206)</b>	\$ (109)	\$ 116
Cash flow from operating activities before changes in non-cash working capital	<b>716</b>	770	768
Expenditures on property, plant and equipment and exploration	<b>760</b>	696	1,707
Daily production, net <i>(before/after royalties)</i>			
– crude oil and liquids <i>(Mbbbls)</i>	<b>82.6/77.9</b>	83.5/77.7	91.3/84.1
– natural gas <i>(MMcft)</i>	<b>126/95</b>	138/95	157/136
Proved reserves <sup>2</sup> <i>(before/after royalties)</i>			
– crude oil and liquids <i>(MMbbls)</i>	<b>278/265</b>	343/294	358/292
– natural gas <i>(Bcf)</i>	<b>300/273</b>	370/323	435/369
Oil and gas landholdings <i>(gross/net) (millions of acres)</i>	<b>31.1/23.5</b>	30.0/22.2	12.9/7.7
Wells drilled <i>(gross/net)</i>			
– oil	<b>24/9</b>	17/9	17/11
– natural gas	<b>9/1</b>	1/0	2/0
– dry	<b>4/1</b>	4/2	7/2
<b>Total</b>	<b>37/11</b>	22/11	26/13

1 Synthetic crude oil is an oil sands mining activity.

2 2004 and 2005 amounts include the mature Syrian producing assets, which were sold on January 31, 2006.

## Three-Year Financial and Operating Summary *continued*

*(stated in millions of Canadian dollars, unless otherwise indicated)*

	2006	2005	2004
<b>Downstream</b>			
Operating earnings	\$ 463	\$ 398	\$ 310
Gain on sale of assets	10	17	4
Net earnings	\$ 473	\$ 415	\$ 314
Cash flow from operating activities before changes in non-cash working capital	790	607	556
Expenditures on property, plant and equipment	1,229	1,053	839
Petroleum product sales <i>(thousands of m<sup>3</sup>/d)</i>	52.5	52.8	56.6
Retail outlets at year end	1,312	1,323	1,375
Refinery crude capacity at year end <i>(thousands of m<sup>3</sup>/d)</i>	40.5	40.5	49.0 <sup>1</sup>
Average refinery utilization (%)	93	96	98
<b>Discontinued Operations</b>			
Operating earnings from discontinued operations	\$ 18	\$ 98	\$ 59
Gain on sale of assets	134	-	-
Net earnings from discontinued operations	\$ 152	\$ 98	\$ 59
Cash flow from discontinued operating activities before changes in non-cash working capital	17	245	204
Expenditures on property, plant and equipment and exploration	1	46	62
Daily production, net <i>(before/after royalties)</i>			
- crude oil and liquids <i>(Mbbbls)</i>	5.2/1.4	65.9/20.3	75.7/23.7
- natural gas <i>(MMcf)</i>	2/-	25/4	21/3
Proved reserves <i>(before/after royalties)</i>			
- crude oil and liquids <i>(MMbbbls)</i>	0/0	44/15	56/19
- natural gas <i>(Bcf)</i>	0/0	15/5	39/13
Oil and gas landholdings <i>(gross/net) (millions of acres)</i>	0/0	0.5/0.2	0.5/0.2
Wells drilled <i>(gross/net)</i>			
- oil	0/0	44/15	39/13
- natural gas	0/0	0/0	0/0
- dry	0/0	5/2	9/4
Total	0/0	49/17	48/17

<sup>1</sup> Capacity revised, on a pro rata basis, from 49,800 m<sup>3</sup>/d (313,000 b/d) in 2003 to reflect partial closure of Oakville refinery operations, effective November 12, 2004.

# Corporate Governance

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Petro-Canada's Board of Directors (the Board) believes that superior corporate governance practices are essential to the Company's success. The Company maintains a best-practices standard in all its corporate governance initiatives and the Corporate Governance and Nominating Committee (the Governance Committee) reviews its corporate governance policies every time it meets.

## **Governance Committee Responsibilities**

The Governance Committee is responsible for overseeing the Company's corporate governance matters and making appropriate recommendations to the Board. In particular, it helps the Board:

- develop and implement corporate governance procedures
- propose nominees for election to the Board
- assess the size, competencies and skills of the Board
- conduct Board, Committee and Director evaluations
- oversee the orientation and education of Board members

## **2006 Governance Initiatives**

This year, the Governance Committee completed a number of governance initiatives, including:

- a gap analysis on Director education to benchmark Petro-Canada's Director orientation and education programs
- reviewing the Board membership matrix in connection with succession planning
- an assessment of the annual Board review process
- revision of the Corporate Governance Handbook

The Company's management regularly reports to the Governance Committee on governance trends, issues and developments.

## **Corporate Governance Practices**

Petro-Canada is a Canadian integrated oil and gas company with shares listed on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE). The Company's corporate governance practices follow the rules and guidelines from both Canadian and U.S. securities regulators, including the following:

<i>Canadian</i>	National Instrument 58-101 (Disclosure of Corporate Governance Practices) National Policy 58-201 (Corporate Governance Guidelines) National Instrument 52-109 (Certification of Disclosure) Multilateral Instrument 52-110 (Audit Committees) (MI 52-110)
<i>U.S.</i>	<i>Sarbanes-Oxley Act of 2002</i> (SOX) NYSE Corporate Governance Standards for U.S domestic issuers (NYSE Standards) <sup>1</sup>

## **Board Composition and Independence**

Petro-Canada's Articles say that the Board must have a minimum of 9 and a maximum of 13 Directors.

Petro-Canada's Board consists of qualified members with backgrounds that help the Company to meet its performance targets. The Board has proposed 11 nominees for election to the Board. Ten are independent; Ron A. Brenneman, Petro-Canada's President and Chief Executive Officer, is the one Director who is not independent under MI 52-110, the NYSE Standards and SOX. The Governance Committee annually reviews the size and effectiveness of the Board as a whole, and the skills and contributions of its members. The Company has an annual process to confirm details on Directors' current employers, other directorships, shareholdings and business relationships. This helps in deciding each Director's independence.

This year, the Governance Committee has recommended to the Board the 11 Board nominees as having the appropriate mix of experience and skill to oversee the stewardship of Petro-Canada. Please see Director Biographies in the Management Proxy Circular for more detail.

<sup>1</sup> Although the NYSE Standards do not apply to Petro-Canada, the Company's corporate governance practices substantially comply with these Standards.

### Board Roles and Responsibilities

The Board supervises the management of Petro-Canada and is responsible for its overall stewardship. In summary, the Board is responsible for:

- management selection, retention, succession and remuneration
- overseeing the development of the Company's business strategy and monitoring its progress
- approving significant Company policies and procedures
- timely and accurate reporting to shareholders and public filing of documents
- approving major Company decisions and documents, including such things as audited financial statements, declaration of dividends, offering circulars and initiation of bylaw amendments

The Board meets at least six times per year and schedules *in camera* sessions at each meeting. In 2006, there were nine Board and *in camera* meetings. The Chair periodically solicits recommendations from Board members on matters that should be brought before the Board. All Directors receive a meeting agenda and background material on agenda items prior to each meeting so that they have the opportunity to review and consider the items that will be discussed. Individual Directors will notify the Board of a material interest in any matter that the Board is considering. The interested Board member is not entitled to participate in Board discussions or vote on the particular matter at the meeting.

The Board Mandate (attached to the Management Proxy Circular as Appendix A) and Terms of Reference for an individual Director contain more detail on the membership, procedures and responsibilities of the Board. These documents can be found in the Corporate Governance Handbook at [www.petro-canada.ca](http://www.petro-canada.ca).

### Board Committees

The Board has five standing Committees:

- Audit, Finance and Risk (Audit Committee)
- Corporate Governance and Nominating (Governance Committee)
- Environment, Health and Safety (EH&S Committee)
- Management Resources and Compensation (Compensation Committee)
- Pension (Pension Committee)

All members of the Committees are independent and *in camera* sessions are scheduled at each Committee meeting. The Governance Committee recommends to the Board the appointees of Committee Chairs. The Chairs of each Committee are responsible for the management, development and effective performance of their Committee. The Chair provides leadership to the Committee, with an aim to fulfilling the Committee's Charter and other matters delegated to it by the Board. The Committee Chairs' mandates are available in the Corporate Governance Handbook at [www.petro-canada.ca](http://www.petro-canada.ca).

The following summarizes the Committees' responsibilities. Each Committee's Charter contains details of its membership, procedures and responsibilities. The Charters can be found in the Corporate Governance Handbook at [www.petro-canada.ca](http://www.petro-canada.ca).

#### *Audit Committee*

All members of the Audit Committee are independent and financially literate. One member is recognized as a "financial expert" in accordance with SOX requirements. *In camera* sessions are held at each Audit Committee meeting, of which there were seven in 2006.

The Audit Committee helps the Board with (i) all matters relating to the external and contract internal auditors, (ii) reviewing and approving the audited financial statements, (iii) reviewing litigation claims, reserves data and related disclosures and (iv) overseeing accounting and risk management policies, reporting practices and internal controls.

### *Governance Committee*

The Governance Committee helps the Board with (i) developing and complying with corporate governance policies and procedures, (ii) recommending candidates for election to the Board and its Committees, (iii) assessing the management, development and effective performance of the Board, its Committees, and their respective Mandates and Charters and (iv) orientation, education and development of Board members. In 2006, there were four Committee and *in camera* meetings.

### *EH&S Committee*

All members of the EH&S Committee are independent and *in camera* sessions are held at each meeting. In 2006, there were three Committee and *in camera* meetings. The EH&S Committee helps the Board with (i) setting strategies, goals, policies and procedures in connection with environment, health and safety matters, (ii) monitoring Petro-Canada's performance in relation to these matters and (iii) complying with environment, health and safety legislation, other related regulatory provisions and public policy.

### *Compensation Committee*

All members of the Compensation Committee are independent and *in camera* sessions are held at each meeting. In 2006, there were four Committee and *in camera* meetings. The Compensation Committee helps the Board with setting the compensation for the President and Chief Executive Officer and other senior officers, as well as overseeing the plans for (i) compensation, development and retention of employees, (ii) succession planning for senior officers and (iii) general compensation and human resource policies and issues.

### *Pension Committee*

All members of the Pension Committee are independent and *in camera* sessions are held at each meeting. In 2006, there were two Committee and *in camera* meetings. The Pension Committee helps the Board with (i) setting strategies, goals, policies and procedures for the Company's pension plan, (ii) effectively governing the pension plan and (iii) monitoring the pension plan's financial position, and its compliance with legislative, regulatory and internal policy requirements.

## **Position Descriptions**

### *Chair of the Board*

The Chair of the Board is an independent Director whose position is separate from the President and Chief Executive Officer. The Chair leads the Board and is responsible for enhancing its effectiveness. The Chair also acts as an advisor to the President and Chief Executive Officer and to other officers in all matters concerning the management of Petro-Canada. The Governance Committee annually reviews the performance of the Chair of the Board.

### *President and Chief Executive Officer*

The President and Chief Executive Officer leads Petro-Canada's Executive Leadership Team. He is responsible for the strategic direction of the Company and its sound management and performance. Each January, the Chair of the Board and the Chair of the Governance Committee canvas the Board members for their input on the President and Chief Executive Officer's performance, request input and comments from other officers as they may see fit and have a detailed discussion with the President and Chief Executive Officer. The Chair of the Board provides an evaluation report to the Management Resources and Compensation Committee, which recommends to the Board the compensation of the President and Chief Executive Officer for the upcoming year.

Detailed position descriptions for the Chair of the Board, Chief Executive Officer and Corporate Secretary are published in the Corporate Governance Handbook available at [www.petro-canada.ca](http://www.petro-canada.ca).

### **Director Evaluation and Compensation**

The Governance Committee annually reviews the size, composition, charters and membership of the Board and each Board Committee, evaluating the effectiveness of the Board, its Committees and the contribution of individual Board members. The Board receives an annual report of the Governance Committee's findings. The Governance Committee also reviews Directors' compensation and recommends Director remuneration of the Board. The main objective is to have the compensation realistically reflect the responsibilities and risk involved in being a Director.

### **Director Orientation and Continuing Education**

We give each new Director copies of:

- business plan and implementation strategy
- annual disclosure documents
- minutes of the Board and Committee meetings for the past year
- Corporate Governance Handbook
- Code of Business Conduct

Each new Director has one-on-one sessions with each of the business unit leaders. As required, we arrange a mentor for every new Director to help them learn about the Company's operations.

Petro-Canada encourages all Directors to take advantage of continuing education programs. The Company supports Directors through a cost-sharing arrangement or by paying all reasonable expenses. Petro-Canada also provides a number of in-house education sessions, such as tours of the Company's facilities and technical paper presentations.

### **Ethical Business Conduct**

*Code of Business Conduct* – All Board members, employees and contractors must follow Petro-Canada's Code of Business Conduct (the Code), which is available on the Company's website ([www.petro-canada.ca](http://www.petro-canada.ca)). The Code provides guidance on such things as ethical business conduct generally, conflicts of interest, dealing with confidential information, insider information and the Policy for the Prevention of Improper Payments. The Board has not granted any waiver of the Code; therefore, no material change report has been filed in this regard.

Annual certificates are provided by Petro-Canada's executive officers verifying that (i) they adhere to the Code, (ii) the Code is regularly communicated and (iii) their employees adhere to the Code. Employees take electronic training on the Code's content and certify their compliance every two years. All new employees must certify that they will comply with the Code during their employment.

*Senior Financial Officers* – Petro-Canada's senior financial officers provide annual certifications under the Company's Code of Ethics for Financial Officers. The President and Chief Executive Officer, and Executive Vice-President and Chief Financial Officer certify the Company's quarterly and annual financial statements for filing with the Canadian and U.S. securities regulators.

*Whistleblower Hotline* – With the Company's whistleblower hotline, employees can report questionable accounting or auditing matters on an anonymous and confidential basis. The Chief Compliance Officer oversees the whistleblower hotline and reports complaints received through the hotline to the Chair of the Audit Committee.

*Disclosure Policy* – Petro-Canada has adopted a Public Disclosure Policy to govern the dissemination of information to the public and further its aim of providing clear and complete disclosure in a timely manner, while complying with all securities regulations. The procedure operating under this Policy establishes a committee that is led by the Executive Vice-President and Chief Financial Officer, and the Vice-President and General Counsel, with representatives from all business and Shared Services units of the Company. Different types of disclosure are approved by all or part of the Committee, as the circumstances warrant. The Chief Financial Officer must approve all material financial disclosures.

This report is submitted by the Corporate Governance and Nominating Committee:

Guyline Saucier (Chair)

Thomas E. Kierans

Maureen McCaw

Brian MacNeill (ex-officio member)

## EXECUTIVE LEADERSHIP TEAM\*

**Ron A. Brenneman**  
President and  
Chief Executive Officer

**Neil J. Camarta**  
Senior Vice-President,  
Oil Sands

**William A. Fleming\*\***  
Vice-President,  
East Coast Oil

**Boris J. Jackman**  
Executive Vice-President,  
Downstream

**Peter S. Kallos**  
Executive Vice-President,  
International

**E.F.H. Roberts**  
Executive Vice-President and  
Chief Financial Officer

**Kathleen E. Sendall**  
Senior Vice-President,  
North American Natural Gas

## ASSOCIATE MEMBERS

**Scott R. Miller**  
Vice-President,  
General Counsel

**M.A. (Greta) Raymond**  
Vice-President, Environment,  
Safety and Social Responsibility

**Andrew Stephens**  
Vice-President,  
Human Resources

## BOARD OF DIRECTORS\*

**Ron A. Brenneman**  
President and  
Chief Executive Officer,  
Petro-Canada

**Angus A. Bruneau, o.c.\*\*\***  
Corporate Director

**Gail Cook-Bennett**  
Chairperson,  
Canada Pension Plan  
Investment Board

**Richard J. Currie, o.c.**  
Chairman of the Board,  
BCE Inc.

**Claude Fontaine, o.c.**  
Counsel,  
Ogilvy Renault LLP

**Paul Haseldonckx**  
Corporate Director

**Thomas E. Kierans, o.c.**  
Chairman,  
Canadian Journalism  
Foundation

**Brian F. MacNeill, c.m.**  
Chairman of the Board,  
Petro-Canada

**Maureen McCaw**  
Corporate Director

**Paul D. Melnuk**  
Chairman and  
Chief Executive Officer,  
Thermadyne Holdings  
Corporation and  
Managing Partner,  
FTL Capital Partners

**Guytaine Saucier, F.C.A., C.M.**  
Corporate Director

**James W. Simpson**  
Corporate Director

## SECRETARY TO THE BOARD OF DIRECTORS

**Hugh L. Hooker**  
Chief Compliance Officer,  
Corporate Secretary and  
Associate General Counsel  
Petro-Canada

\*As of December 31, 2006.

\*\*Mr. Fleming retired in February 2007.

\*\*\*Dr. Bruneau will retire at the end of the Annual Meeting on April 24, 2007.

Please see the 2007 Management Proxy Circular for additional information about Petro-Canada's senior officers, Board of Directors and governance practices. The Management Proxy Circular contains disclosure on executive compensation and contracts, reports of Board of Directors' Committees and a description of each Committee's responsibilities, a Statement of Corporate Governance Practices and detail on Directors' business backgrounds, tenure, Committee membership, remuneration and share ownership. The Management Proxy Circular is available for viewing on our website at [www.petro-canada.ca](http://www.petro-canada.ca) or by contacting Investor Relations.

# Investor Information

## Outstanding Shares

At December 31, 2006, Petro-Canada's public float was 497,538,385 shares.

## Transfer Agent and Registrar

In Canada:

CIBC Mellon Trust Company

In the United States:

Mellon Investor Services, LLC

Telephone: 416-643-5000

Fax: 416-643-5660 or 416-643-5661

E-mail: [inquiries@cibcmellon.com](mailto:inquiries@cibcmellon.com)

Website: [www.cibcmellon.com](http://www.cibcmellon.com)

## Duplicate Reports

Shareholders with more than one unregistered account may receive duplicate materials. To eliminate duplicate mailings, contact your broker. Registered shareholders should contact the transfer agent and registrar.

## Annual Meeting

The Annual Meeting of Shareholders of Petro-Canada will be held at 11:00 a.m. (MDT) on Tuesday, April 24, 2007, in Macleod Room 2 at the Telus Convention Centre, 120 9 Avenue S.E., Calgary, Alberta.

## Stock Exchange Listings and Symbols

Toronto: PCA

New York: PCZ

## Dividends

Petro-Canada's Board of Directors approves a quarterly dividend of \$0.13 (\$0.52 per annum) per common share. The Board of Directors regularly reviews the dividend strategy to ensure alignment with shareholders' expectations and financial and growth objectives.

## On the Website

Petro-Canada's website, [www.petro-canada.ca](http://www.petro-canada.ca), contains a variety of corporate and investor information, including

- Statistical Supplement
- Annual Information Form
- Quarterly Reports
- Management Proxy Circular
- Corporate Governance Practices (including the Company's Corporate Governance Handbook)
- Presentations and Webcasts
- Dividend History

- Petro-Canada's Code of Business Conduct
- Petro-Canada's Principles for Investment and Operations
- Report to the Community

## Investor Inquiries

Telephone: 403-296-4040

Fax: 403-296-3061

E-mail: [investor@petro-canada.ca](mailto:investor@petro-canada.ca)

## Media Inquiries

Corporate Communications

Telephone: 403-296-3648

## General Inquiries

Petro-Canada

P.O. Box 2844

Calgary, Alberta, Canada T2P 3E3

Telephone: 403-296-8000

Fax: 403-296-3030

Website: [www.petro-canada.ca](http://www.petro-canada.ca)

## We Would Like Your Feedback

We invite your comments on our Annual Report. Please e-mail your comments to [aranson@petro-canada.ca](mailto:aranson@petro-canada.ca).

# Glossary of Terms and Ratios

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## TERMS

### Barrel of Oil Equivalent

Natural gas production is converted using six thousand cubic feet of gas for one barrel of oil.

### Capital Employed

Total of shareholders' equity and debt.

### Cash Flow

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

### Debt

Short-term notes payable and long-term debt, including current portion.

### Operating Earnings

Net earnings before gains or losses on foreign currency translation, on disposal of assets and the unrealized gain or loss associated with the Buzzard derivative contracts.

### Life-of-Field Production

The estimated volume of hydrocarbons to be recovered from a reservoir or field in the period from start of production to abandonment. Typically, it refers to the estimated proved plus probable reserves.

## RATIOS

### Return on Capital Employed

Net earnings plus after-tax interest expense divided by average capital employed. Measures net earnings relative to the capital employed in the Company.

### Operating Return on Capital Employed

Earnings from operations plus after-tax interest expense divided by average capital employed.

### Cash Flow Return on Capital Employed

Cash flow plus after-tax interest expense divided by average capital employed. Measures cash flow generated relative to the asset base.

### Return on Equity

Net earnings divided by average shareholders' equity. Measures the return earned by shareholders on their investment in the Company.

### Debt-to-Cash Flow

Debt divided by cash flow. Indicates the Company's ability to discharge its outstanding debt.

### Debt-to-Debt Plus Equity

Debt divided by debt plus equity. Indicates the relative amount of debt in the Company's capital structure. Measures financial strength.

### Book Value per Share

Total shareholders' equity divided by the number of shares outstanding at year end.

## Interest Coverage

Measures the Company's ability to cover interest charges on debt.

### *Net earnings basis*

Net earnings from continuing operations before interest expense and income taxes divided by interest expense plus capitalized interest.

### *EBITDAX basis*

Net earnings from continuing operations before interest expense, provision for income taxes, depreciation, depletion and amortization and exploration expenses divided by interest expense plus capitalized interest.

### *Cash flow basis*

Cash flow from continuing operations before interest expense and current income taxes divided by interest expense plus capitalized interest.

## CONVERSION FACTORS

To conform with common usage, imperial units of measurement are used in this report to describe exploration and production, while metric units are used for refining and marketing. Dollars are Canadian unless otherwise stated.

1 cubic metre (liquids) = 6.29 barrels

1 cubic metre (natural gas) =

35.30 cubic feet

1 litre = 0.22 imperial gallons

1 hectare = 2.47 acres

1 cubic metre = 1,000 litres

⊕ Design: Bhandari & Plater Inc. Printing: Transcontinental Yorkville-O'Keefe Photography: (as it appears) Chris Thomas, Greg Locke, Joëlle Opelik, Klaas Slot, Joëlle Opelik, unknown, Matthew Plexman and Mike Sturk.

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Clear. Capable. Committed.

**GENERAL INQUIRIES**

Petro-Canada

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Telephone: 403-296-8000 Fax: 403-296-3030

*To learn more about Petro-Canada,  
please visit our website at [www.petro-canada.ca](http://www.petro-canada.ca).*

