Energy Leadership

Yesterday, Today and Tomorrow

Annual report 2006

The energy challenge

Energy is fundamental to world economic and social development, but finding, developing and supplying hydrocarbons – the most sought-after form of energy – is a complex, long-term proposition. Major energy projects, once started, require years to implement while locking in significant amounts of upfront capital.

As a leading energy provider, we anticipate global energy trends and plan accordingly. Our annual forecast looks out to 2030 – premised upon energy demand increasing with economic and population growth.

Even with energy efficiency improvements of about one percent a year over this period, we expect global energy demand to grow by about 1.6 percent a year. Growth in energy use will be strongest in developing countries such as China, India and those in Latin America – as economies, populations and living standards increase – but demand will also increase in North America. Globally, the energy equivalent of about 325 million barrels a day of oil will be required from all forms of energy by 2030 – about a 60-percent increase over 2000.

Resources are available to meet the challenge

Hydrocarbons – oil, natural gas and coal – will continue to supply about 80 percent of the world's energy needs, while oil and natural gas alone will account for about 60 percent. Hydrocarbons are abundant, and remain adequate to support global demand growth, but access to frontier-area resources and large, timely investments will be needed to bring these resources to market. Global trade, particularly for oil and natural gas, will continue to grow to meet the demand. Canada's largely untapped heavy oil and oil sands deposits – with estimated recoverable resources of about 15 times the total oil production to date from Alberta – will become an increasingly important contributor to world supply.

Technological advances will also be vital to the world's energy future: expanding supply by developing previously unrecoverable resources; mitigating demand growth by improving energy efficiency; and reducing the environmental impacts of increased energy use.

Corporate profile

Imperial Oil is one of Canada's largest corporations and a leading member of the country's petroleum industry. It is one of Canada's largest producers of crude oil and natural gas, is the country's largest petroleum refiner, and has a leading market share in petroleum products, sold primarily under the Esso and Mobil brand names through a coast-to-coast supply network that includes close to 2,000 service stations.

The Imperial Oil **advantage**

Proven, consistent strategy:

- Continually improving base operations – to enhance safety, efficiency and attain best-in-class costs;
- Developing one of Canada's leading resource positions – in a disciplined and environmentally responsible manner;
- Maintaining the highest ethical standards – adhering to long-held core values at every level of the organization.

Talented, dedicated employees – the foundation of the company's success.

Technology leadership – using a disciplined research and development process that improves existing operations and unlocks new resources and products.

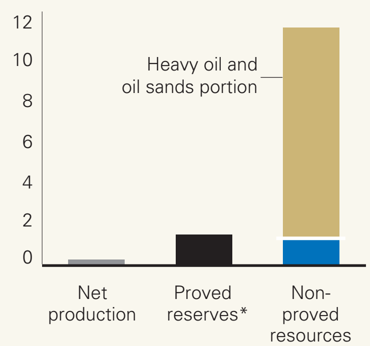
Unparalleled financial strength – a straightforward business model that enables pursuit of all opportunities that provide attractive returns for shareholders.

Superior shareholder returns – a record of creating shareholder value – the total return was 12.5 percent in 2006 and has averaged 22 percent a year over the past 10 years.

Contents

Significant resource base

billions of oil-equivalent barrels – 2006

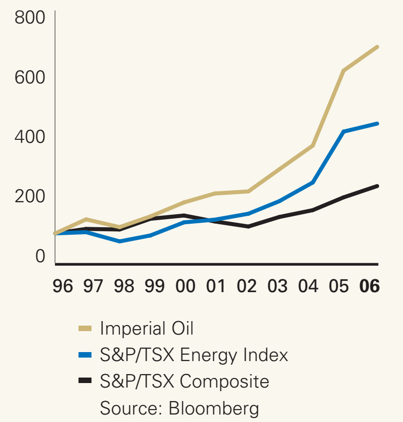


· Significant resource base of about 13.5 billion oil-equivalent barrels.
· Non-proved resources of about 12 billion oil-equivalent barrels, of which about 10.5 billion barrels are heavy oil and oil sands.
· Long-life reserves.

* Based upon prices the company uses to make investment decisions; see page 60 for estimates based upon the U.S. Securities and Exchange Commission's requirement that applies December 31st prices and costs.

Sustained increase in shareholder value

10-year cumulative total returns
Value of $100 invested on December 31, 1996



Source: Bloomberg

Letter to shareholders

In the hierarchy of human needs, energy ranks high. It is essential to economic progress and the advancement of living standards. Never has this been more true than in today's world. Current energy forecasts suggest that, as economies develop and populations increase, global energy demand will continue to grow – by as much as 60 percent more than the year 2000 by 2030. Meeting this demand will require all economic forms of energy, and chief among them will be oil and natural gas. Canada will become an increasingly important energy supplier, with its vast hydrocarbon resources, strong workforce, and stable government and regulatory regime.

Our company continues to contribute to Canada's energy future by being an industry leader, all the while increasing shareholder value.

In 2006, record earnings of more than $3 billion ($3.11 per share) were generated. Underpinning this performance were higher oil prices as well as strong refining margins, supported by global demand for energy products.

More than $2 billion was returned to shareholders through share repurchases and dividends, and for the 12th year in a row, regular per-share annual dividend payments were raised. Total return to shareholders, including share appreciation and dividends, was 12.5 percent in 2006 and has averaged 22 percent a year over the past 10 years.

These results were achieved during a period of unprecedented industry growth. This high level of activity put pressure on costs, reinforcing the need to execute a consistent strategy – one that is simple to articulate but hard to emulate. It involves ensuring operational excellence, maintaining investment discipline and engaging in prudent financial management. It's a proven strategy that has contributed to long-term growth in shareholder value.

Last year, progress was achieved on all fronts.

In terms of operational excellence, overall safety performance continued to be strong, but there was some increase in injury frequency. We are confident that initiatives being implemented will improve performance. In addition, we carried out extensive refinery modifications to produce ultra-low sulphur diesel, on time, on budget and without lost-time injuries. This major undertaking delivers a new generation of fuel with fewer vehicle emissions and cleaner air for all of us. We also continued to upgrade the retail network in major urban markets, strengthening our position in a highly competitive market.

As we continued efforts to strengthen operations, investments to advance growth projects were also made. Regulatory hearings progressed for two major energy projects, Kearl oil sands and Mackenzie natural gas. Exploration drilling with co-venturers began in the Orphan Basin off Canada's East Coast. A multi-year, $8.5-billion upgrader expansion project at Syncrude, in which Imperial has a 25-percent interest, was also completed. This raised capacity to 350,000 barrels a day, thereby maintaining Syncrude's place as the world's largest producer of synthetic crude from oil sands.

Prudent financial management also continued. At year-end, the total debt-to-capital ratio was 17 percent. Our "AAA" rating on debt from Standard & Poor's was maintained. And at 36 percent, return on capital employed was once again among the best in the energy industry. This strength enabled all of the $1.2 billion in capital and exploration expenditures to be made from internally generated funds.

Looking ahead, I believe our future holds much promise. Various elements distinguish us in the marketplace. There is the strength of our workforce, whose quality and dedication are at the root of our company's success. We have one of Canada's leading resource positions and a steadfast commitment to strategically focused research and technology development. We have access to global-scale best practices through our relationship with Exxon Mobil Corporation. And finally, there is our focus on discipline. We have a clear vision of our business and how to run it, maintaining close attention to systems, sound governance, ethics, integrity, safety as well as environmental and operating excellence.

So we begin 2007 with confidence. The future is both challenging and exciting. As always, we are determined to build upon our position as a leading energy provider in Canada, dedicated to increasing shareholder value.

T. Hearn

Tim Hearn

Chairman, president and chief executive officer
February 14, 2007

Major energy projects and opportunities

Mackenzie Delta, N.W.T.

Kearl, Alta.

Cold Lake, Alta.

Syncrude, Alta.

Orphan Basin, Nfld.

Mackenzie natural gas project

The Mackenzie natural gas project would bring about six trillion cubic feet of discovered natural gas to North American markets. Imperial's wholly-owned Taglu field represents about half of this resource. A regulatory decision is expected in 2008.

Kearl oil sands project

Canada's oil sands are a world-class resource – and Kearl is one of the industry's largest and highest-quality proposed oil sands projects. The total recoverable resource is 4.6 billion barrels of bitumen before royalties, of which Imperial holds about a 70-percent interest. A regulatory decision is expected in early 2007.

Cold Lake heavy oil operation

The Cold Lake heavy oil operation is Canada's premier thermal in-situ development. Record average annual production was achieved in 2006, and the operation will continue to expand in 2007.

Syncrude oil sands operation

The Stage 3 expansion was completed at Syncrude, one of the most ambitious engineering projects in Canadian history – including an upgrader expansion that increased the facility's capacity to 350,000 barrels of synthetic crude oil a day.

Orphan Basin project

Exploration off the East Coast of Newfoundland has started in a vast, largely unexplored basin. The first well on the leases was drilled in over 2,300 metres of water – one of the deepest water-depth wells ever drilled in Canada.

Year in review

Operating highlights

Safety and environment

- Overall safety performance continued to be strong, although there was some increase in injury frequency, particularly for contractors in Alberta.
- Advanced several environment-driven projects and met all regulatory milestones in the production and sale of ultra-low sulphur diesel fuel – a $500-million project that was completed on budget, on time and with no lost-time injuries in about 3.2 million hours worked.
- The improvements achieved in recent years in environmental performance were sustained.

Progressed major projects and new opportunities

- Completed the Stage 3 expansion at Syncrude, increasing capacity to 350,000 barrels of synthetic crude oil a day.
- Completed regulatory hearings on the proposed Kearl oil sands project near Fort McMurray, with a total recoverable resource of 4.6 billion barrels of bitumen before royalties, of which Imperial holds about a 70-percent interest. The regulatory decision is expected in 2007.
- Advanced preliminary engineering and design work on the proposed Mackenzie natural gas project. Regulatory hearings commenced in 2006 and were extended into 2007.
- Began drilling a wildcat exploration well with co-venturers in the Orphan Basin off the East Coast of Newfoundland, with two follow-up wells planned by the end of 2008.

Strong volume performance

- Average daily production of crude oil, natural gas and natural gas liquids increased to 364,000 oil-equivalent barrels a day before royalties, about a two percent increase compared with 2005.
- Net petroleum product sales volumes averaged 71.9 million litres a day and Imperial remained the largest petroleum refiner in Canada.
- Achieved record production at the Cold Lake heavy oil operation, averaging about 152,000 barrels a day before royalties.

Research and development

- Maintained an industry-leading research program at Sarnia and Calgary. Total research expenditures in Canada were $56 million in 2006, and four patents were awarded. In addition, through its relationship with Exxon Mobil Corporation, Imperial had access to more than $800 million of industry-leading research worldwide.

Corporate citizenship

- Supported the evolving needs of Canadian communities with total contributions of $12.4 million. Of this, the Imperial Oil Foundation contributed $6 million to more than 250 organizations. The Foundation focuses on developing science and math skills in Canadian youth, environmental initiatives and community development in locations where the company has a significant presence. More than $2.1 million was directed to educational initiatives in 2006. The company's corporate citizenship report provides more information on these and other initiatives. It can be accessed at www.imperialoil.ca.

Financial highlights

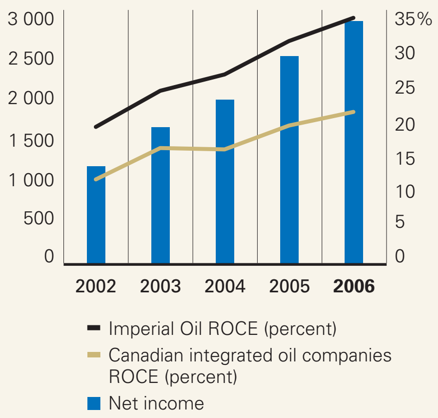
	2006	2005	2004	2003	2002
Net income (millions of dollars)	**3 044**	2 600	2 052	1 705	1 214
Net income per share (dollars) (a) – diluted	**3.11**	2.53	1.91	1.53	1.07
Return on average shareholders' equity (percent) (b)	**43.5**	40.2	34.6	32.6	26.5
Return on average capital employed (percent) (c)	**35.9**	32.6	27.7	25.3	20.0
Annual shareholders' return (percent) (d)	**12.5**	64.0	25.3	30.5	3.2

(a) Calculated by reference to the average number of shares outstanding, weighted monthly (page 62). Adjusted to reflect the three-for-one share split.
(b) Net income divided by average shareholders' equity (page 38).
(c) A definition of return on average capital employed can be found on page 32.
(d) Includes share appreciation and dividends.

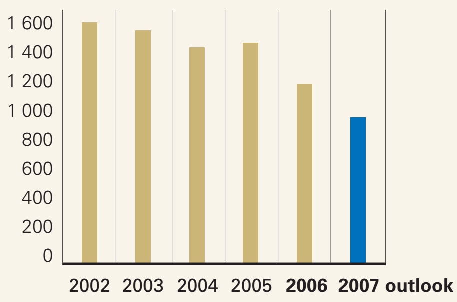
Financial highlights

- Achieved record earnings of $3.0 billion or $3.11 per share, up from the previous record of $2.6 billion or $2.53 per share in 2005.
- Maintained an industry-leading return on capital employed of 36 percent.
- Total shareholder return, including share appreciation and dividends, was 12.5 percent.
- Increased annual per share dividends paid for the 12th year in a row.
- Sustained total shareholder distributions of $2.1 billion (comprised of dividend payments and share repurchases).
- Completed a three-for-one share split.
- Maintained a strong balance sheet. Debt as a percentage of total capital was 17 percent; interest coverage was 66 times on an earnings basis and 77 times on a cash flow basis.
- Maintained a "AAA" rating from Standard & Poor's – Imperial is the only Canadian industrial company with such a rating.
- Completed a $1.2-billion capital and exploration program, which included the funding of major upstream projects and significant refinery upgrades.
- Projected capital and exploration expenditures for 2007 are estimated to be $1 billion and will focus primarily on growth, including future reserve additions and productivity improvements. These expenditures will be financed through internally generated funds.

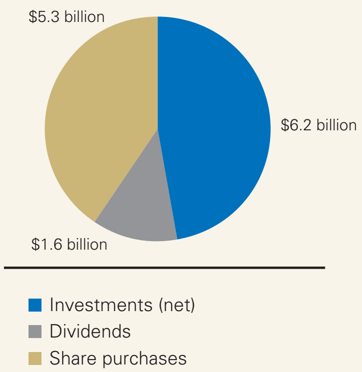
Net income millions of dollars
Return on average capital employed (ROCE) percent



Capital and exploration expenditures
millions of dollars



Long-term use of cash
five-year total (2002–2006), $13.1 billion



Natural resources

Natural resources at a glance

	2006	2005	2004	2003	2002
Net income (millions of dollars)	**2 376**	2 008	1 517	1 174	1 052
Cash flow from operating activities and asset sales (millions of dollars)	**3 151**	2 805	2 395	1 729	1 276
Gross crude oil and NGL production (thousands of barrels a day)	**272**	261	262	256	247
Gross natural gas production (millions of cubic feet a day)	**556**	580	569	513	530
Capital employed at December 31 (millions of dollars)	**4 080**	3 905	3 951	3 802	3 335
Return on average capital employed (percent)	**59.5**	51.1	39.1	32.9	35.4

Cold Lake's "megapads" improve the economics of recovery and minimize surface footprint.

Multiple projects, many of which are major in size and scope, were advanced in 2006, positioning the company for significant long-term volume growth to more than offset the natural decline in conventional production.

Imperial is developing one of Canada's leading resource positions, with a non-proved resource of about 12 billion oil-equivalent barrels and proved reserves of 1.5 billion oil-equivalent barrels.

The upstream business continued its record of superior operating performance in 2006. Total production before royalties increased to 364,000 oil-equivalent barrels a day before royalties, compared with 358,000 barrels a day in 2005. Record earnings of $2,376 million were generated, with cash flow from operating activities and asset sales of $3,151 million and return on capital employed of 59.5 percent.

Capital and exploration spending in 2006 totalled $787 million and about $700 million is planned for 2007 – largely for future reserve additions and production growth.

Heavy oil and oil sands

As a pioneer in the development of heavy oil and the oil sands, Imperial's technological and operational expertise has created a strong foundation for the ongoing development of one of Canada's leading resource bases – including more than 10 billion barrels of these resources.

Total production from heavy oil and oil sands was 217,000 barrels a day before royalties in 2006.

Cold Lake

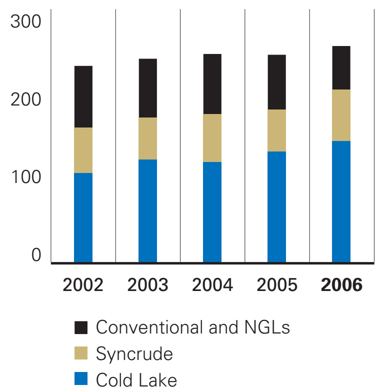
The Cold Lake heavy oil operation is a premier asset.

Record average production of 158,000 barrels of oil a day before royalties was achieved in the third quarter, and averaged a record 152,000 barrels a day before royalties for the year.

Wholly owned and operated by Imperial, work on Cold Lake began over 40 years ago. Large-scale development began in the 1980s – with a phased approach that continues today – enabling new technologies to be fully applied at each stage of development.

The current expansion to the north of the existing operating area is using "megapad" technology, in which a single large surface location, or pad, is used with vertical as well as horizontal wells. One megapad can access as much as three standard pads, which minimizes the surface footprint, reduces development costs and improves economics. Imperial also patented a completion technique to optimize production associated with megapads.

Crude oil and NGL production by source
thousands of barrels a day before royalties



In 2006, crude oil and NGL production was 272,000 barrels a day, up four percent from 2005.

Natural resources continued

Following a successful multi-year field test at Cold Lake, a process was patented in 2005 that enhances recovery by adding solvent to current steaming technology. Commercial implementation will begin in 2007.

Also, for certain types of deposits, the addition of solvent to wells that employ steam-assisted gravity drainage technology has shown promising results during laboratory testing. A pilot is being planned to further test the technology and gain the operational experience necessary to potentially build a commercial operation in the future.

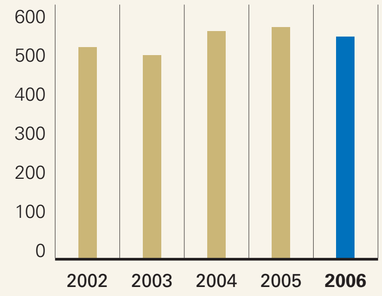
The locations of each of Cold Lake's four major plants were carefully considered in order to ensure that recovery of the area's heavy oil resources was optimized, and costs were minimized. Today, with a 780 square kilometre lease area containing about 800 kilometres of pipelines, initiatives to minimize additional infrastructure investment continue to be pursued, such as the ongoing infill drilling program that improves recovery in areas adjacent to existing plants.

Operations at Cold Lake include a 170-megawatt cogeneration facility. Constructed in 2002, the plant provides energy efficiency benefits by generating electricity at the same time as steam is made for the heavy oil recovery process. The operation is self-reliant in electricity, and is a net contributor of electricity to the Alberta power grid.

Syncrude

Located near Fort McMurray, Syncrude is the world's largest producer of synthetic crude oil from oil sands. Production from Imperial's 25-percent interest in the operation, where oil sands are mined and upgraded, was 65,000 barrels a day before royalties in 2006, up from 53,000 barrels a day in 2005.

Natural gas production
millions of cubic feet
a day before royalties



In 2006, natural gas production was 556 million cubic feet a day, down four percent from 2005.

Proved reserves of crude oil and natural gas (a)

	Crude oil and NGLs millions of barrels						Natural gas billions of cubic feet		Synthetic crude oil millions of barrels	
	Conventional		Heavy Oil		Total					
year ended	gross	net	gross	net	gross	net	gross	net	gross	net
2002	175	146	895	801	1 070	947	1 445	1 224	893	800
2003	151	126	853	763	1 004	889	1 204	1 023	874	781
2004 (b)	134	110	783	702	917	812	1 034	880	835	757
2005 (b)	95	77	753	683	848	760	927	765	816	738
2006 (b)	**81**	**65**	**667**	**616**	**748**	**681**	**830**	**673**	**792**	**718**

(a) Gross reserves are the company's share of reserves before deducting the shares of mineral owners or governments or both. Net reserves exclude these shares.

(b) Based upon prices the company uses to make investment decisions; see page 60 for estimates based upon the U.S. Securities and Exchange Commission's requirement that applies December 31st prices and costs.

The completion of the upgrader expansion project contributed to the production increase. This included the start-up of a third 100,000 barrel a day coker that will add about 25,000 barrels a day to Imperial's share of volumes. Sustained operation of the upgrader expansion project began in August 2006, following a prolonged start-up period. Imperial's share of the total cost of the expansion project was about $2.1 billion.

In the fall of 2006, Imperial announced plans to enter into a Management Services Agreement with Syncrude Canada Ltd., the operating company for the Syncrude joint venture. Under the agreement, Imperial and ExxonMobil will provide global best practices in areas such as maintenance and reliability, energy management, safety and health, procurement and environmental performance – with the expectation of delivering further sustainable improvements in Syncrude's operating performance. Imperial has a final checkpoint in the second quarter of 2007 to confirm or cancel the agreement, following completion of an opportunity assessment study.

Kearl oil sands project

Located northeast of Fort McMurray, the proposed Kearl oil sands project is one of the best new undeveloped oil sands mining opportunities in Alberta's Athabasca region, with an estimated total recoverable resource of about 4.6 billion barrels of bitumen before royalties – and the potential to produce about 300,000 barrels a day over a 40-year plus lifespan.

The project advanced significantly during 2006. The mine application and related environmental impact assessment were filed in 2005 and public hearings took place in November 2006. The conclusion of the hearings represented a significant milestone for the Kearl project – the successful end to two years of preparation by a large, multi-disciplinary team. The regulatory decision is expected early in 2007, and if the project proceeds, Imperial will hold about a 70-percent interest and will act as operator in a joint venture with ExxonMobil Canada.

Imperial has a 25-percent interest in Syncrude, the world's largest producer of synthetic crude from oil sands.

About the Syncrude expansion

Taking place between 2001 and 2006, the Stage 3 expansion was one of the most ambitious engineering projects in Canadian history. With a peak workforce of more than six thousand, the expansion required an estimated 43 million field hours of work. The project involved an expanded mining and extraction facility at the Aurora mine site, in addition to an upgrader expansion that increased the facility's capacity to 350,000 barrels a day, representing about 13 percent of Canada's crude oil production.

The expansion included new froth treatment and diluent recovery units, as well as a new fluid coker, distillate hydroprocessor, hydrogen plant, sulphur plant, amine plant, sour water treater and flue gas scrubber. New utilities facilities included cooling towers and a condensing turbine generator.

In addition to increasing production and enhancing product quality across Syncrude's entire production stream, the expansion project included investments to improve environmental performance by reducing sulphur dioxide emissions and increasing energy efficiency.

Natural resources continued

Conventional Western Canada

Imperial remains one of Canada's largest domestic producers of conventional crude oil and natural gas. Production before royalties averaged about 55,000 barrels a day of crude oil and natural gas liquids and about 556 million cubic feet a day of natural gas, for a combined total of approximately 148,000 oil-equivalent barrels a day.

Although a mature business in Western Canada, high profitability and strong returns continue, due in large part to an unwavering focus on keeping unit operating costs low while maximizing production. For certain properties where oil reserves have been economically depleted, "blowing down" of the remaining gas caps continued to perform well in 2006, adding to profitability. The largest of these blowdowns, at Wizard Lake, performed better than expected, though production should continue to decline in 2007 as the gas cap is depleted.

While gas cap blowdowns contribute to current production, new natural gas opportunities are being pursued to help offset natural declines, such as continued drilling along the foothills of Alberta and the ongoing shallow-gas program in southeastern Alberta, where more than 300 wells were drilled in 2006. Additional drilling is planned for 2007 and beyond.

Kearl: A world-class resource

Kearl is a world-class resource in both size and quality. A key quality indicator for mineable oil sands is the ratio of total volume to be mined relative to bitumen in place. This ratio measures the amount of material that needs to be processed to produce a barrel of bitumen – a lower ratio is preferable as it will lead to lower operating costs. Kearl's average ratio for the entire 4.6 billion barrels of recoverable resource before royalties is one of the lowest of the currently proposed oil sands projects industry wide.

Plans for Kearl involve the use of proven technologies, such as truck-and-shovel mining, hydrotransport and bitumen froth extraction, as well as newer technologies, such as high-performance paraffinic froth treatment. Selectively integrating newer technology into proven designs lowers the execution and start-up risks, and will enhance overall performance. In addition, the company continues to progress innovative technologies that could be incorporated into initial phases once operating, or adopted into the design of subsequent expansions. Developing and deploying proprietary technologies will be key to further enhancing the Kearl project over its operating life.

A phased development approach enables better management of capital construction costs – and Kearl has been designed with that in mind. The initial phase has a planned capacity of 100,000 barrels a day, with two subsequent phases bringing the total to about 300,000 barrels a day.

Current efforts are focused upon design optimization to improve project economics and reduce execution risk. Once this work is completed and a regulatory decision is received, project timing will be determined.

Core sampling on the Kearl oil sands lease.

East Coast

The East Coast of Canada is one of the country's newest regions of petroleum production and holds significant potential for further development.

Imperial has a nine-percent interest in the Sable offshore energy project, a major natural gas production venture currently producing from five fields in relatively shallow waters 250 kilometres southeast of Halifax. Additional gas compression capacity was added in 2006 – at a net cost to Imperial of about $67 million – to maintain gas production volumes.

The Orphan Basin is a vast, largely unexplored offshore region with favourable characteristics for hydrocarbons. It is located in the deep waters off the East Coast of Newfoundland and Labrador, where Imperial holds a 15-percent interest in eight parcels. Following two 3-D seismic programs that were conducted over 2004 and 2005, the first wildcat exploration well was spudded in August 2006. Complementing 3-D seismic, a survey using a new ExxonMobil research technology was acquired in 2006 to help identify future drill targets. The technology – called R3M – will be a significant competitive advantage in continued Orphan Basin exploration. Two more exploration wells are planned by the end of 2008.

Mackenzie natural gas project

The proposed Mackenzie gas project represents an important new source of natural gas for North America. This Imperial-operated joint venture would bring to market six trillion cubic feet of previously discovered onshore natural gas from three anchor fields in the Mackenzie River Delta area of Northern Canada. Imperial's wholly-owned Taglu field accounts for about half of the discovered gas resource in the Mackenzie Delta, and is one of the continent's best undeveloped gas resources.

The Mackenzie gas project includes development of the three anchor fields, a natural gas gathering system, a gas-processing plant near Inuvik and the Mackenzie Valley pipeline itself. Anchor field production is projected to be about 830 million cubic feet a day, while the ultimate capacity of the pipeline is 1.8 billion cubic feet a day. The project would utilize proven technology to develop the resource and bring it to market, employing state-of-the-art techniques to minimize environmental impact. The proposed project would have a separate natural-gas liquids line from Inuvik to Norman Wells, at which point the liquids would be shipped via the existing crude oil line to Northern Alberta.

In 2006, Imperial carried out engineering, geotechnical and environmental fieldwork in support of project definition and permit applications, advanced benefits and access agreements, and was actively involved in the regulatory hearings process.

Regulatory hearings were extended into 2007, as the panel conducting the environmental and social review of the project announced that it would require several extra months of hearings, and additional time to compile its report. And in November, a federal court ruling, relating to traditional land use by a First Nation along the pipeline route in Northern Alberta, added further delay to the process.

As with all major energy projects today, the Mackenzie gas project is facing significant cost and schedule pressures brought on by unprecedented global demands for energy infrastructure. Bringing the project to completion will take co-operation among many different parties, including energy companies, northern communities, regulatory agencies and governments. Current work efforts are focused upon completing regulatory hearings, advancing approval of permits, finalizing remaining benefits and access agreements, establishing an appropriate fiscal framework with the federal government, advancing potential shipping agreements and continuing paced engineering, technical and cost-reduction efforts.

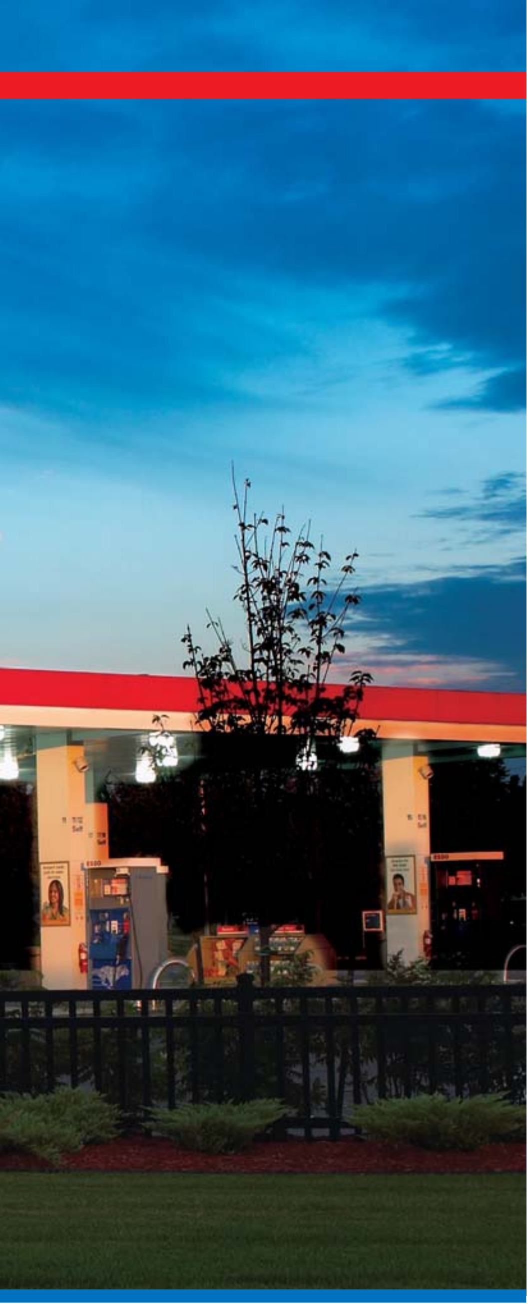
National Energy Board regulatory approval alone will not be sufficient for the project to go forward. Prior to approving the project for construction, the uncertainties related to the permitting process by the northern regulatory boards and other government agencies must be resolved, and the economic impact of the cost estimate increase must be addressed.

Petroleum products

Petroleum products at a glance

	2006	2005	2004	2003	2002
Net income (millions of dollars)	**624**	694	556	462	147
Cash flow from operating activities and asset sales (millions of dollars)	**562**	874	946	706	448
Refinery throughput (thousands of barrels a day)	**442**	466	467	450	447
Net petroleum product sales (millions of litres a day)	**71.9**	73.9	73.4	70.4	69.2
Capital employed at December 31 (millions of dollars)	**3 285**	3 037	2 774	2 888	2 551
Return on average capital employed (percent)	**19.7**	23.9	19.6	17.0	6.2

An Esso service station in Mississauga, Ont., one of about 2,000 serving Canadian motorists nationwide.



Imperial is the largest petroleum refiner in Canada and has a leading market share in petroleum product sales, including retail fuels and finished lubricants.

Imperial markets more than 700 different petroleum products, the majority of which are sold under the Esso and Mobil brands, including sales through the company's 1,960 service stations nationwide.

Downstream operations performed well overall in 2006. Net earnings from petroleum products were $624 million or 2.4 cents a litre – compared with last year's record of $694 million, or 2.6 cents a litre. Operating results were impacted by the higher planned refinery maintenance and capital project work undertaken in 2006. Return on average capital employed was 20 percent and cash flow from operating activities and asset sales was $562 million.

Total refinery throughput of about 442,000 barrels a day was down from 2005, largely due to comprehensive planned maintenance and project work required for the completion of new ultra-low sulphur diesel facilities. Total net petroleum product sales were 71.9 million litres a day – down from 2005, primarily due to lower refinery production.

Capital investment in petroleum products totalled $361 million in 2006, and was directed primarily to investments to produce ultra-low sulphur diesel, maintain and upgrade the retail network, and deliver safety, environmental and efficiency improvements. With the completion of the ultra-low sulphur diesel project, planned capital expenditures in 2007 will be about $250 million, and will focus upon productivity and efficiency investments and further upgrades to the retail network.

The petroleum products industry is global in nature and increasingly competitive. And while North American industry refining margins were higher in 2006, they were largely offset by the impact of a higher Canadian dollar.

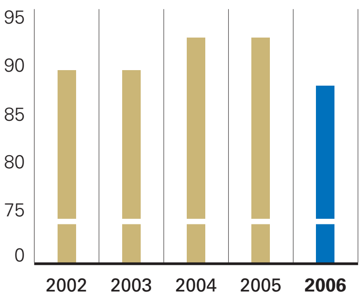
Imperial's petroleum products business is focused upon the key elements of its business within its control – increasing reliability and efficiency of its base operations; achieving and sustaining best-in-class costs; and continuing to upgrade its asset base.

The refining business made a number of investments in 2006 to meet regulatory requirements and further enhance refinery performance and competitiveness – the most notable of which was the completion of the $500-million ultra-low sulphur diesel project. Lower diesel sulphur levels, together with new heavy-duty engine technology, will result in lower vehicle emissions and improved air quality. Careful planning and project execution enabled Imperial to meet each of the government's sulphur-reduction milestones on budget, on schedule and most importantly, with no lost-time injuries in about 3.2 million hours worked. Other refinery investments included measures to improve energy efficiency, conversion capacity and capability for blending ethanol in gasoline.

While strengthening long-term competitiveness, extensive planned maintenance and major project activity decreased refinery utilization to 88 percent in 2006 – below the record performance level of 93 percent in 2005 and 2004.

Refinery utilization

percent



Extensive planned maintenance and major project activity decreased average refinery utilization to 88 percent in 2006.

Petroleum products continued

In December, a fire at the Sarnia refinery damaged the hydrocracking unit. No injuries or environmental exceedances occurred as a result of the fire, there were no near-term product shortages, and the affected unit is being repaired.

Within the fuels marketing business, the Esso service station network provides customers with one-stop shopping convenience, has a leading share of retail market gasoline sales, the largest network of carwashes in Canada and the second-largest convenience store network in the country. The strength of our On the Run convenience store offer is complemented by strategic alliances with Tim Hortons, Royal Bank and Aeroplan – all leading brands in their industries. In 2006, same-store sales from our convenience stores grew by about four percent.

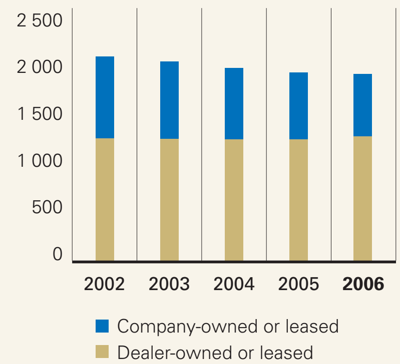
In 2006, upgrading of the retail network continued in major urban markets. Part of the improvement included the addition of the 300th On the Run store to the chain – only five years after the program launch. The network upgrades helped increase average productivity of company-owned or leased service stations by about four percent and enabled a reduction in unit operating costs – thereby strengthening Imperial's position in a highly competitive retail environment.

Imperial remains a leading branded retail marketer in Canada due, in part, to a long history of product and service innovation. In 2006, this commitment to innovation included the launch of the *Speedpass* pay-at-the-pump debit payment option for Royal Bank customers and the testing in five Toronto-area On the Run-branded stores of select *President's Choice* grocery products.

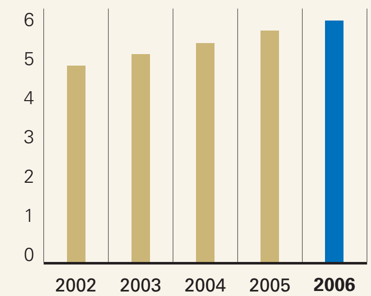
Imperial operates manufacturing, blending and packaging facilities for lubricants in both the east and the west – the only Canadian company to do so. Selling under the Esso and Mobil brands, Imperial is the Canadian market-share leader for finished lubricants. To retain this position, the company continues to conduct advanced research on base stocks, process oils and finished lubricants. In 2006, the Sarnia Research Centre reformulated more than 140 finished lubricant products to meet evolving market needs and commercialized 24 new products. Highlights included the development of Canada's most advanced natural gas engine oil and the launch of the next-generation heavy-duty diesel engine oil.

Supplying fuel and lubricants products to key sectors of the Canadian economy for many years, Imperial's industrial & wholesale, aviation, marine and lubricants businesses continued to serve mining, manufacturing, forestry, construction and transportation industries across the country in 2006.

Esso service stations
average number



Annual throughput – company-owned or leased service stations
millions of litres per site



Average productivity at company-owned or leased service stations was 6.1 million litres in 2006, up about four percent from 2005.

Trademarks:
- Mobil, On the Run and *Speedpass* are trademarks of Exxon Mobil Corporation or one of its subsidiaries.
- RBC and Royal Bank are registered trademarks of Royal Bank of Canada.
- *President's Choice* is a registered trademark of Loblaws Inc.
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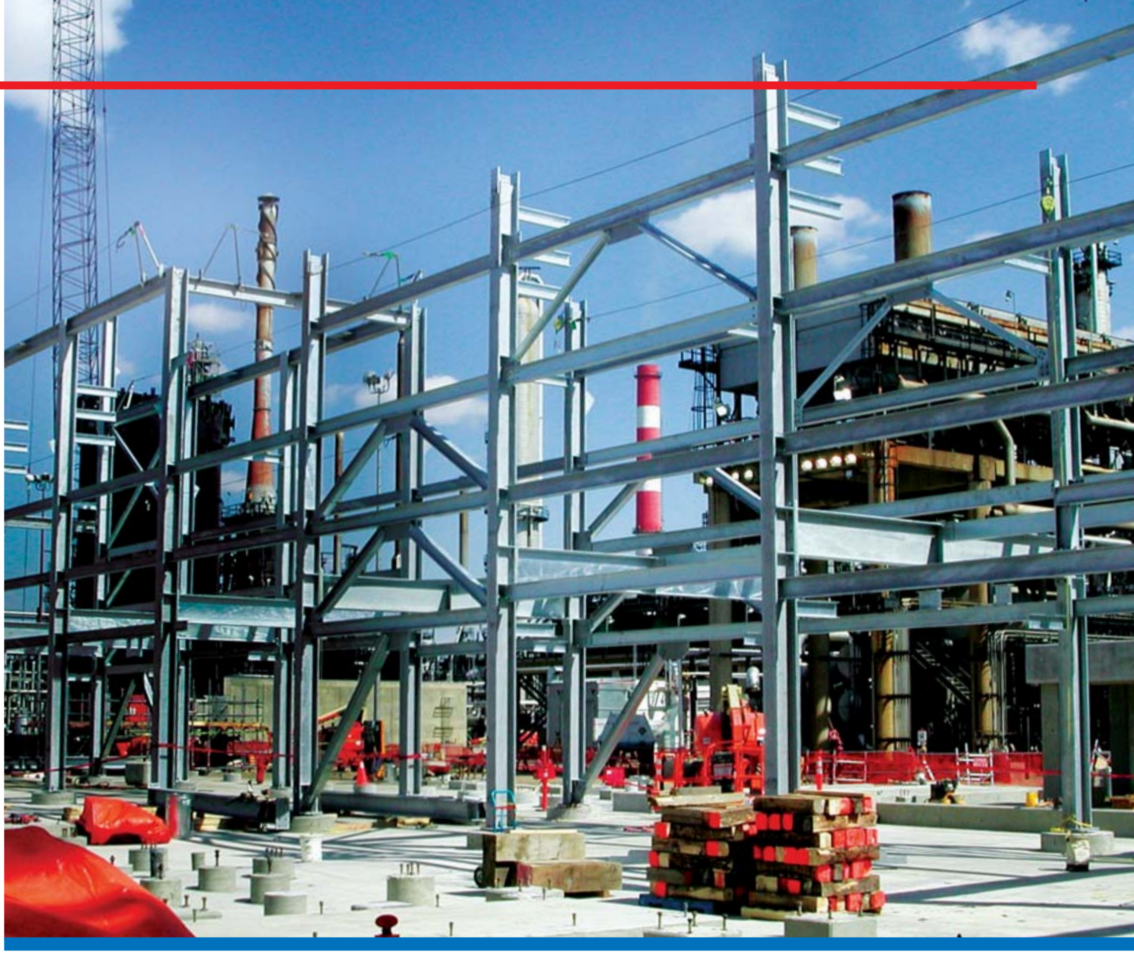
- Aeroplan is a registered trademark of Aeroplan Limited Partnership.



The ultra-low sulphur diesel project required the efforts of over five thousand people to complete.

During the year, work undertaken on the Sarnia refinery catalytic cracking unit increased its capacity.

Incrementally increasing refining capacity and high-value product yield

Imperial has long employed a strategy to increase the throughput and capacity of its refinery operating units through a combination of operations optimization and selective investment. Investment in incremental refinery expansions is generally less costly than spending on grassroots facilities. In making these investments, Imperial leverages the technology, best practices and operating experience available within both its own refinery network and that of ExxonMobil in order to deliver cost-effective de-bottleneck solutions.

Upgrading of heavier crude oil components into higher-value "light" products (such as gasoline and diesel) occurs in a refinery's conversion units. In 2006, projects at each of Imperial's refineries increased capacity of the fluid catalytic cracking units by six percent, increasing the refineries' capability to upgrade low-value products to high-value products, primarily gasoline.

Such refining capacity growth throughout Canada and the United States over the past two decades has generally been sufficient to keep pace with demand growth in mature markets, such as North America.

Other improvement initiatives implemented during the year focused upon increasing refinery capability to process a variety of economic feedstocks and reduce raw material costs. For example, the Strathcona refinery increased its capability to process sour and synthetic crude oils in response to a diminishing supply of Western Canadian conventional sweet crude oil. Similarly, the Nanticoke refinery continued to increase its capability to process Cold Lake blend to manufacture asphalt.

Chemicals

Chemicals at a glance

	2006	2005	2004	2003	2002
Net income (millions of dollars)	**143**	121	109	44	54
Cash flow from operating activities and asset sales (millions of dollars)	**162**	94	126	36	99
Chemical sales volumes (thousands of tonnes a day)	**3.0**	3.0	3.3	3.3	3.5
Capital employed at December 31 (millions of dollars)	**241**	281	262	260	188
Return on average capital employed (percent)	**54.8**	44.6	41.8	19.6	27.5

The Sarnia polyethylene and aromatics control rooms were consolidated into one location in 2006.

Imperial is one of Canada's leading producers of chemical products with the largest market share in North America for polyethylene used in rotational molding and the second largest market share in injection molding. The chemicals business also has the largest share of the domestic fluids market, which includes the popular Esso-branded Varsol solvent.

Chemicals net earnings in 2006 were a record $143 million, up 18 percent from 2005. Cash flow from operating activities and asset sales was $162 million.

Earnings growth was largely due to improved industry margins across all product lines. Strong polyethylene industry margins were driven by increased global demand.

Total sales of petrochemical products were 3,000 tonnes a day, unchanged from 2005.

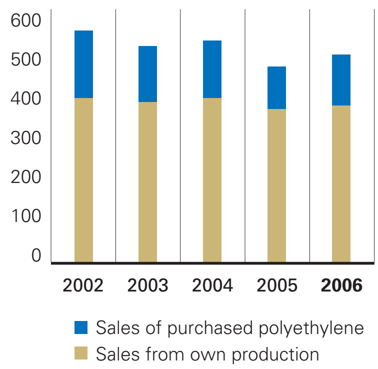
The company was able to maintain production despite third-party operating problems in a pipeline system that constrained feedstock supply from Western Canada into the Sarnia polyethylene plant. This plant continues to be one of the most cost-competitive operations in North America. Typical end uses of Imperial's polyethylene production include flexible food packaging, toys, pails and various other containers.

Capital expenditures in 2006 were $13 million, down from $19 million in 2005. Investments included consolidation of control facilities at the Sarnia plant as well as incrementally increasing the capacity of the facility. Initiatives such as these continue to help keep the chemicals business a leader in productivity and cost performance. Planned expenditures in 2007 will be $15 million, most of which will be directed to reliability, energy conservation initiatives and incremental capacity increases at the Sarnia plant.

Like the petroleum products industry, the chemicals business operates in a competitive, global marketplace that is cyclical.

The chemicals segment has focused upon the key elements of its business within its control, continuing to integrate petrochemical manufacturing with the refinery. This integration enables feedstocks and production to be adjusted to current market conditions – and to reduce costs by sharing management, efficiently managing energy needs across the site, and leveraging common site infrastructure.

Polyethylene sales
thousands of tonnes per year



Financial summary (U.S. GAAP)

millions of dollars	**2006**	2005	2004	2003	2002
Operating revenues (a)	**24 505**	27 797	22 408	19 094	16 890
Net income by segment:					
Natural resources	**2 376**	2 008	1 517	1 174	1 052
Petroleum products	**624**	694	556	462	147
Chemicals	**143**	121	109	44	54
Corporate and other	**(99)**	(223)	(130)	25	(39)
Net income	**3 044**	2 600	2 052	1 705	1 214
Total assets	**16 141**	15 582	14 027	12 337	12 003
Long-term debt	**359**	863	367	859	1 466
Total debt	**1 437**	1 439	1 443	1 432	1 538
Other long-term obligations	**1 683**	1 728	1 525	1 314	1 822
Capital employed	**8 898**	8 131	7 821	7 029	6 498
Cash flow from operating activities and asset sales	**3 799**	3 891	3 414	2 283	1 749
Per-share information (dollars) (b)					
Net income per share – basic	**3.12**	2.54	1.92	1.53	1.07
Net income per share – diluted	**3.11**	2.53	1.91	1.53	1.07
Dividends	**0.32**	0.31	0.29	0.29	0.28

(a) Operating revenues include $4,894 million for 2005, $3,584 million for 2004, $2,851 million for 2003 and $2,431 for 2002 for purchases/sales contracts with the same counterparty. Associated costs were included in "purchases of crude oil and products". Effective January 1, 2006, these purchases/sales were recorded on a net basis. See note 1, Summary of Significant Accounting Policies, on page 40.

(b) Adjusted to reflect the three-for-one share split.

Management's discussion and analysis of financial condition and results of operations

Overview

The following discussion and analysis of Imperial's financial results, as well as the accompanying financial statements and related notes to consolidated financial statements to which they refer, are the responsibility of the management of Imperial Oil Limited.

The company's accounting and financial reporting fairly reflect its straightforward business model involving the extracting, refining and marketing of hydrocarbons and hydrocarbon-based products. The company's business involves the production (or purchase), manufacture and sale of physical products, and all commercial activities are directly in support of the underlying physical movement of goods.

Imperial, with its resource base, financial strength, disciplined investment approach and technology portfolio, is well-positioned to participate in substantial investments to develop new Canadian energy supplies. While commodity prices remain volatile on a short-term basis depending upon supply and demand, Imperial's investment decisions are based on its long-term outlook, using a disciplined approach in selecting and pursuing the most attractive investment opportunities. The corporate plan is a fundamental annual management process that is the basis for setting risk-assessed, near-term operating and capital objectives, in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Potential investment opportunities are tested over a wide range of economic scenarios to establish the resiliency of each opportunity. Once investments are made, a reappraisal process is completed to ensure relevant lessons are learned and improvements are incorporated into future projects. Imperial views return on capital employed as the best measure of historical capital productivity.

Business environment and outlook

Natural resources

Imperial produces crude oil and natural gas for sale into large North American markets. Economic and population growth are expected to remain the primary drivers of energy demand, globally and in North America. The company expects the global economy to grow at an average rate of slightly less than three percent per year through 2030. The combination of population and economic growth should lead to an increase in demand for primary energy at an average rate slightly less than two percent annually. The vast majority of this increase is expected to occur in developing countries.

Oil, gas and coal are expected to remain the predominant energy sources with approximately 80 percent share of total energy. Oil and gas alone are expected to maintain close to a 60 percent share.

Over the same period, the Canadian economy is expected to grow at an average rate of about two percent per year, and Canadian demand for energy at a rate of about one percent per year. Oil and gas are expected to continue to supply two-thirds of Canadian energy demand. It is expected that Canada will also be a growing supplier of energy to U.S. markets through this period.

Oil products are the transportation fuel of choice for the world's fleet of cars, trucks, trains, ships and airplanes. Primarily because of increased demand in developing countries, oil consumption will increase by 35 percent or about 30 million barrels a day by 2030. Canada's resources of heavy oil (a) and oil sands (b) represent an important additional source of supply.

Natural gas is expected to be a major primary energy source globally, capturing about one-third of all incremental energy growth and approaching one-quarter of global energy supplies. Natural gas production from mature established regions in the United States and Canada is not expected to meet increasing demand, strengthening the market opportunities for new gas supply from Canada's frontier areas.

Crude oil and natural gas prices are determined by global and North American markets and are subject to changing supply and demand conditions. These can be influenced by a wide range of factors, including economic conditions, international political developments and weather. In the past, crude oil and natural gas prices have been volatile, and the company expects that volatility to continue.

Imperial has a large and diverse portfolio of oil and gas resources in Canada, both developed and undeveloped, which helps reduce the risks of dependence on potentially limited supply sources in the upstream. With the relative maturity of conventional production in the established producing areas of Western Canada, Imperial's production is expected to come increasingly from frontier and unconventional sources, particularly heavy oil, oil sands and natural gas from the Far North, where Imperial has large undeveloped resource opportunities.

Petroleum products

The downstream industry environment remains very competitive. While refining margins in 2006 were strong, long-term real refining margins globally have declined at a rate of about one percent per year over the past 20 years. Intense competition in the retail fuels market similarly has driven down real margins. Refining margins are the difference between what a refinery pays for its raw materials (primarily crude oil) and the wholesale market prices for the range of products produced (primarily gasoline, diesel fuel, heating oil, jet fuel and heavy fuel oil). Crude oil and many products are widely traded with published international prices. Prices for those commodities are determined by the marketplace, often an international marketplace, and are affected by many factors, including global and regional supply/demand balances, inventory levels, refinery operations, import/export balances, transportation logistics, seasonality and weather. Canadian wholesale prices in particular are largely determined by wholesale prices in adjacent U.S. regions. These prices and factors are continually monitored and provide input to operating decisions about which raw materials to buy, facilities to operate and products to make. However, there are no reliable indicators of future market factors that accurately predict changes in margins from period to period.

Imperial's downstream strategies are to provide customers with quality service at the lowest total cost offer, have the lowest unit costs among our competitors, ensure efficient and effective use of capital and capitalize on integration with the company's other businesses. Imperial owns and operates four refineries in Canada, with distillation capacity of 502,000 barrels a day and lubricant manufacturing capacity of 9,000 barrels a day.

Imperial's fuels marketing business includes retail operations across Canada serving customers through about 1,960 Esso-branded service stations, of which about 650 are company-owned or leased, and wholesale and industrial operations through a network of 30 primary distribution terminals, as well as a secondary distribution network.

Chemicals

Although the current business environment is favourable, the North American petrochemical industry is cyclical. The company's strategy for its chemicals business is to reduce costs and maximize value by continuing to increase the integration of its chemicals plants at Sarnia and Dartmouth with the refineries. The company also benefits from its integration within ExxonMobil's North American chemicals businesses, enabling Imperial to maintain a leadership position in its key market segments.

(a) Heavy oil typically is represented by crude oils with a viscosity of greater than 10,000 cP and recovered through enhanced thermal operations.
(b) Oil sands are a semi-solid material composed of bitumen, sand, water and clays, which are recovered through surface mining methods.

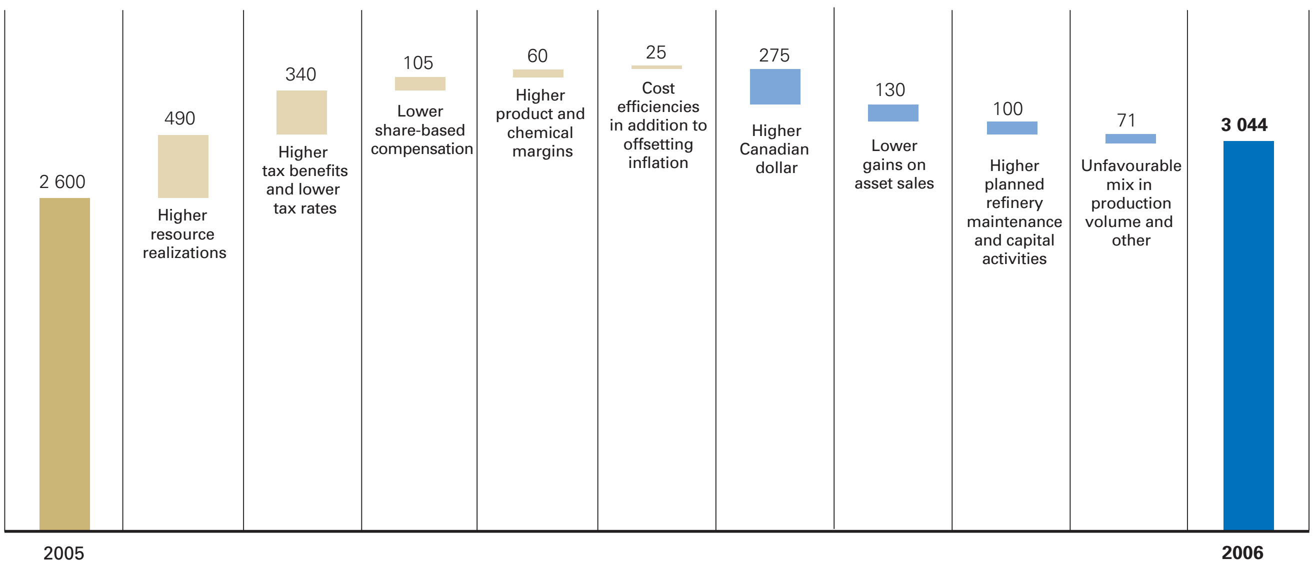
Management's discussion and analysis of financial condition and results of operations (cont'd)

Results of operations

Net income in 2006 was $3,044 million or $3.11 a share – the best year on record – surpassing the previous record of $2,600 million or $2.53 a share in 2005 (2004 – $2,052 million or $1.91 a share). Higher realizations for Cold Lake heavy oil and conventional crude oil contributed about $640 million and stronger refining, marketing and petrochemical margins about $60 million more to earnings when compared with 2005. Also positive to earnings were higher benefits from resolution of tax matters and the impact of tax rate changes of about $340 million and lower share-based compensation expenses of about $105 million. Partially offsetting these positive factors were the impacts of a stronger Canadian dollar of about $275 million, lower natural gas realizations of about $150 million, lower gains on asset divestments of about $130 million, higher planned refinery maintenance and capital project effects of about $100 million and a heavier mix of resources volumes of about $60 million.

The return on average capital employed was 36 percent, compared with 33 percent in 2005 (2004 – 28 percent).

Factors affecting Imperial's 2006 net income
millions of dollars



Effective December 31, 2006, the company adopted Statement of Financial Accounting Standards No. 158 (SFAS 158) and the post-retirement benefit liability recognized under this standard is reported in the corporate and other segment. To be consistent, the minimum pension liability recognized under SFAS 87 and previously included in the operating segments in 2005 and prior years has been reclassified to the corporate and other segment. See notes 2 and 6 to the consolidated financial statements on pages 43 and 47, respectively, for further details on SFAS 158 requirements and impact.

This change has the effect of increasing capital employed in the operating segments and decreasing capital employed in the corporate and other segment, resulting in no impact on the company's overall capital employed. Operating segments' return on average capital employed (ROCE) became lower as a result, but overall ROCE for the company remained unchanged. This reclassification improves the comparability of Imperial's capital employed and ROCE in the operating segments with those in other companies in the industry.

Natural resources

Net income from natural resources was a record $2,376 million, exceeding the previous record achieved in 2005 of $2,008 million (2004 – $1,517 million). Cold Lake heavy oil and conventional crude oil realizations were stronger by about $640 million compared with 2005. These positive items were partially offset by lower natural gas realizations of about $150 million and the negative impact of a higher Canadian dollar of about $200 million. The impact of natural resources volumes was unfavourable by about $60 million due to mix effects with lower conventional crude oil volumes being partially offset by higher Syncrude volumes. Higher production at Cold Lake was essentially offset by higher royalties. Tax expense in 2006 was lower by about $290 million, primarily from reductions in federal and Alberta tax rates and higher benefits from resolution of tax matters. Gains from asset divestments were lower by about $130 million compared with 2005.

Return on average capital employed was 60 percent for the natural resources segment, compared with 51 percent in 2005 (2004 – 39 percent), reflecting higher net income.

Financial statistics

millions of dollars	**2006**	2005	2004	2003	2002
Net income	**2 376**	2 008	1 517	1 174	1 052
Operating revenues	**8 456**	8 189	6 580	5 584	4 790
Cash flow from operating activities and asset sales	**3 151**	2 805	2 395	1 729	1 276
Capital employed at December 31	**4 080**	3 905	3 951	3 802	3 335
Return on average capital employed (percent)	**59.5**	51.1	39.1	32.9	35.4

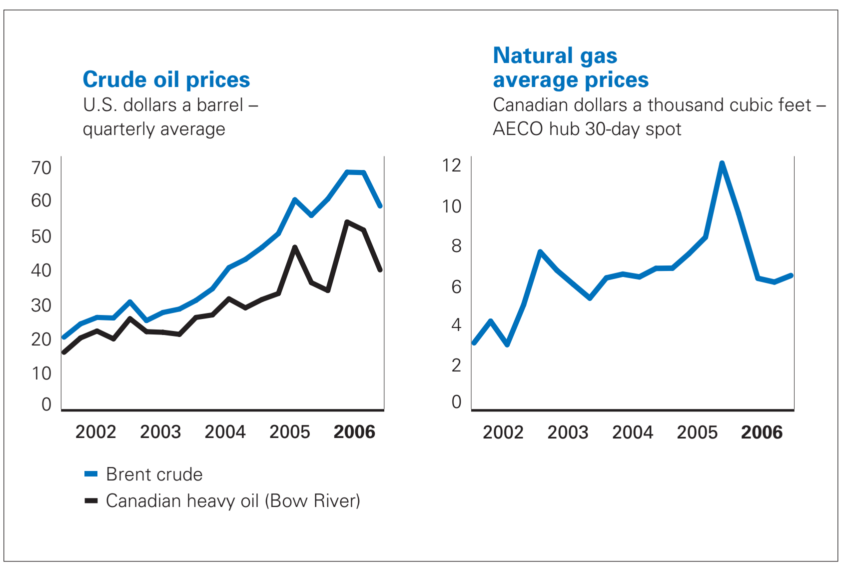
World crude oil prices, denominated in U.S. dollars, were higher in 2006 than in the previous year. The annual average price of Brent crude oil, the most actively traded North Sea crude and a common benchmark of world oil markets, was about $65 (U.S.) a barrel in 2006, a more than 19 percent increase over the average price of $55 in 2005 (2004 – $38). However, the company's Canadian-dollar realizations for conventional crude oil increased to a lesser extent because of a stronger Canadian dollar. Average realizations for conventional crude oil during the year were $68.58 (Cdn) a barrel, an increase of six percent from $64.48 in 2005 (2004 – $48.96).

Average realizations for Cold Lake heavy oil were higher by over 40 percent in 2006, reflecting both increases in light crude oil prices and a narrowing price spread between light crude oil and Cold Lake heavy oil more consistent with historical trend levels.

Prices for Canadian natural gas in 2006 were lower than the previous year. The average of 30-day spot prices for natural gas at the AECO hub in Alberta was about $7.41 a thousand cubic feet in 2006, compared with $9.01 in 2005 (2004 – $6.80). The company's average realizations on natural gas sales were $7.24 a thousand cubic feet, compared with $9 in 2005 (2004 – $6.78).

Average realizations and prices

Canadian dollars	**2006**	2005	2004	2003	2002
Conventional crude oil realizations (a barrel)	**68.58**	64.48	48.96	40.10	36.81
Natural gas liquids realizations (a barrel)	**40.75**	40.00	33.78	32.09	23.38
Natural gas realizations (a thousand cubic feet)	**7.24**	9.00	6.78	6.60	4.02
Par crude oil price at Edmonton (a barrel)	**73.75**	69.86	53.26	43.93	40.44
Heavy oil price at Hardisty (Bow River, a barrel)	**51.90**	45.62	37.98	33.00	31.85



Total gross production of crude oil and natural gas liquids (NGLs) averaged 272,000 barrels a day, compared with 261,000 barrels in 2005 (2004 – 262,000).

Gross heavy oil production at the company's wholly owned facilities at Cold Lake was a record 152,000 barrels a day, surpassing the previous record of 139,000 barrels in 2005 (2004 – 126,000), due to the cyclic nature of production at Cold Lake and increased volumes from the ongoing development drilling program.

Production from the Syncrude oil sands operation, in which the company has a 25 percent interest, was higher during 2006 as a result of lower maintenance activities and new production volume from the new coker unit at the Stage 3 expansion project. Gross production of upgraded crude oil increased to 258,000 barrels a day from 214,000 barrels in 2005 (2004 – 238,000). Imperial's share of average gross production increased to 65,000 barrels a day from 53,000 barrels in 2005 (2004 – 60,000).

Gross production of conventional oil decreased to 31,000 barrels a day from 38,000 barrels in 2005 (2004 – 43,000) as a result of the impact of divested properties and the natural decline in Western Canadian reservoirs.

Gross production of NGLs available for sale averaged 24,000 barrels a day in 2006, down from 31,000 barrels in 2005 (2004 – 33,000), mainly due to the declining NGL content of Wizard Lake gas production.

Gross production of natural gas decreased to 556 million cubic feet a day from 580 million cubic feet in 2005 (2004 – 569 million). Lower production volumes were primarily due to the natural decline in the Western Canadian Basin.

In 2006, the company realized a gain of $76 million on divestment of assets. In 2005, the gain on divestment of assets was approximately $208 million.

Crude oil and NGLs – production and sales (a)

thousands of barrels a day	**2006**		2005		2004		2003		2002	
	gross	net	gross	net	gross	net	gross	net	gross	net
Cold Lake	**152**	**127**	139	124	126	112	129	116	112	106
Syncrude	**65**	**58**	53	53	60	59	53	52	57	57
Conventional crude oil	**31**	**23**	38	29	43	33	46	35	51	39
Total crude oil production	**248**	**208**	230	206	229	204	228	203	220	202
NGLs available for sale	**24**	**19**	31	25	33	26	28	22	27	21
Total crude oil and NGL production	**272**	**227**	261	231	262	230	256	225	247	223
Cold Lake sales, including diluent (b)	**198**		183		167		170		145	
NGL sales	**29**		39		42		39		40	

Natural gas – production and sales (a)

millions of cubic feet a day	**2006**		2005		2004		2003		2002	
	gross	net	gross	net	gross	net	gross	net	gross	net
Production (c)	**556**	**496**	580	514	569	518	513	457	530	463
Sales	**513**		536		520		460		499	

(a) Daily volumes are calculated by dividing total volumes for the year by the number of days in the year. Gross production is the company's share of production (excluding purchases) before deducting the share of mineral owners or governments or both. Net production excludes those shares.
(b) Diluent is natural gas condensate or other light hydrocarbons added to the Cold Lake heavy oil to facilitate transportation to market by pipeline.
(c) Production of natural gas includes amounts used for internal consumption with the exception of the amounts reinjected.

Operating costs decreased by one percent in 2006. Lower energy and other operating costs more than offset higher Syncrude expenses.

In November, the company announced plans to enter into a management services agreement with Syncrude Canada Ltd., the operating company for the Syncrude joint venture. The company has a final checkpoint in the second quarter of 2007 to confirm or cancel the agreement following completion of an opportunity assessment study.

Petroleum products

Net income from petroleum products was $624 million or 2.4 cents a litre in 2006, compared with $694 million or 2.6 cents a litre in 2005 (2004 – $556 million or 2.1 cents a litre). Earnings were negatively impacted by higher planned refinery maintenance and ultra-low sulphur diesel project activities, which impacted both refinery utilization and expenses by a total of about $100 million versus the prior year. Lower product sales volumes during the year were primarily a result of lower refinery production and had limited impact on earnings, as the reduction was primarily in lower margin refining and marketing sales channels. Earnings were also negatively impacted by a stronger Canadian dollar of about $65 million. These factors were partially offset by the net positive effect of resolution of tax matters and the impact of the tax rate change, totalling about $55 million, and stronger refining and marketing margins.

Return on average capital employed was 20 percent for the petroleum products segment, compared with 24 percent in 2005 (2004 – 20 percent).

Financial statistics

millions of dollars	**2006**	2005	2004	2003	2002
Net income	**624**	694	556	462	147
Operating revenues (a)	**20 783**	24 017	19 169	16 004	14 400
Cash flow from operating activities and asset sales	**562**	874	946	706	448
Capital employed at December 31	**3 285**	3 037	2 774	2 888	2 551
Return on average capital employed (percent)	**19.7**	23.9	19.6	17.0	6.2

Sale of petroleum products

millions of litres a day (b)	**2006**	2005	2004	2003	2002
Gasolines	**32.7**	33.4	33.2	33.0	32.9
Heating, diesel and jet fuels	**26.4**	26.9	27.3	26.2	25.0
Heavy fuel oils	**5.1**	6.0	5.9	5.4	4.9
Lube oils and other products	**7.7**	7.6	7.0	5.8	6.4
Net petroleum product sales	**71.9**	73.9	73.4	70.4	69.2
Total domestic sales of petroleum products (percent)	**96.1**	95.3	93.0	93.3	91.5

Refinery utilization

thousands of barrels a day (b)	**2006**	2005	2004	2003	2002
Total refinery throughput (c)	**442**	466	467	450	447
Refinery capacity at December 31	**502**	502	502	502	499
Utilization of total refinery capacity (percent)	**88**	93	93	90	90

(a) Operating revenues in 2005 and prior years included amounts for purchases/sales with the same counterparty. Associated costs were included in "purchases of crude oil and products". Effective January 1, 2006, these purchases/sales were recorded on a net basis. See note 1, Summary of Significant Accounting Policies, on page 40.

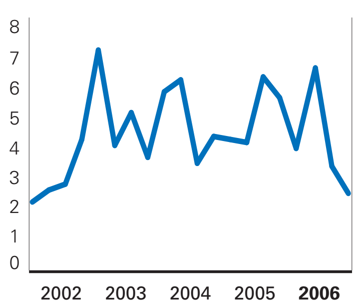
(b) Volumes a day are calculated by dividing total volumes for the year by the number of days in the year.

(c) Crude oil and feedstocks sent directly to atmospheric distillation units.

One thousand litres is approximately 6.3 barrels.

Average refining margins

Canadian cents a litre



New York Harbor product prices minus Brent crude, reflects Imperial's product mix

Margins were stronger in the refining segment of the industry in 2006. However, the effects of stronger industry margins were reduced partially by a higher Canadian dollar. Marketing margins in 2006 were slightly higher than the low levels of 2005.

Impacted by higher planned maintenance and ultra-low sulphur diesel project activities, refinery utilization for 2006 at 88 percent was lower than the record performance level of 93 percent in both 2005 and 2004.

The company's total sales volumes, excluding those resulting from reciprocal supply agreements with other companies, were 71.9 million litres a day, compared with 73.9 million litres in 2005 (2004 – 73.4 million). Lower refinery production was the main reason for the decline.

Operating costs in 2006 were essentially the same as the previous year.

Chemicals

Net income from chemicals operations was $143 million in 2006, the best on record, compared with $121 million in 2005 (2004 – $109 million). Improved industry margins for polyethylene and intermediate products were the main contributors to higher earnings.

Return on average capital employed was 55 percent for the chemicals segment, compared with 45 percent in 2005 (2004 – 42 percent).

Financial statistics

millions of dollars	**2006**	2005	2004	2003	2002
Net income	**143**	121	109	44	54
Operating revenues	**1 704**	1 665	1 509	1 232	1 164
Cash flow from operating activities and asset sales	**162**	94	126	36	99
Capital employed at December 31	**241**	281	262	260	188
Return on average capital employed (percent)	**54.8**	44.6	41.8	19.6	27.5

Sales

thousands of tonnes a day (a)	**2006**	2005	2004	2003	2002
Polymers and basic chemicals	**2.2**	2.1	2.4	2.4	2.5
Intermediate and others	**0.8**	0.9	0.9	0.9	1.0
Total chemicals	**3.0**	3.0	3.3	3.3	3.5

(a) Calculated by dividing total volumes for the year by the number of days in the year.

The average industry price of polyethylene was $1,703 a tonne in 2006, essentially unchanged from $1,708 a tonne in 2005 (2004 – $1,584).

Sales of chemicals were 3,000 tonnes a day, unchanged from 2005 (2004 – 3,300 tonnes).

Operating costs in the chemicals segment for 2006 were about four percent lower than 2005, reflecting lower direct operating expenses.

Corporate and other

Net income from corporate and other was negative $99 million in 2006, compared with negative $223 million in 2005 (2004 – negative $130 million). Favourable earnings effects were due mainly to lower share-based compensation expenses.

Liquidity and capital resources

Sources and uses of cash

millions of dollars	**2006**	2005
Cash provided by/(used in)		
Operating activities	**3 587**	3 451
Investing activities	**(965)**	(992)
Financing activities	**(2 125)**	(2 077)
Increase/(decrease) in cash and cash equivalents	**497**	382
Cash and cash equivalents at end of year	**2 158**	1 661

Although the company issues long-term debt from time to time and maintains a revolving commercial paper program, internally generated funds cover the majority of its financial requirements. The management of cash that may be temporarily available as surplus to the company's immediate needs is carefully controlled, both to optimize returns on cash balances and to ensure that it is secure and readily available to meet the company's cash requirements as they arise.

Cash flows from operating activities are highly dependent on crude oil and natural gas prices and product margins. In addition, the company will need to continually find and develop new resources, and continue to develop and apply new technologies and recovery processes to existing fields, in order to maintain or increase production and resulting cash flows in future periods. Projects are in place or underway to increase production capacity. However, these volume increases are subject to a variety of risks, including project execution, operational outages, reservoir performance and regulatory changes.

The company's financial strength enables it to make large, long-term capital expenditures. Imperial's large and diverse portfolio of development opportunities and the complementary nature of its business segments help mitigate the overall risks of the company and associated cash flow. Further, due to its financial strength, debt capacity and diverse portfolio of opportunities, the risk associated with failure or delay of any single project would not have a significant impact on the company's liquidity or ability to generate sufficient cash flows for its operations and fixed commitments.

Cash flow from operating activities

Cash provided by operating activities was $3,587 million, versus $3,451 million in 2005 (2004 – $3,312 million). Increases in cash flow in 2006 were driven primarily by higher net income and lower overall working capital balances.

Capital and exploration expenditures

Total capital and exploration expenditures were $1,209 million in 2006, compared with $1,475 million in 2005 (2004 – $1,445 million).

The funds were used mainly to invest in Cold Lake and Syncrude to maintain and expand production capacity, improve operating efficiency, reduce the sulphur content of diesel fuel and upgrade the network of Esso retail outlets. About $170 million was spent on projects related to reducing the environmental impact of the company's operations and improving safety, including about $95 million on the $500-million project to produce ultra-low sulphur diesel.

The following table shows the company's capital and exploration expenditures for natural resources during the five years ending December 31, 2006:

millions of dollars	**2006**	2005	2004	2003	2002
Exploration	**32**	43	60	57	39
Production	**237**	232	234	181	143
Heavy oil and oil sands	**518**	662	819	769	804
Total capital and exploration expenditures	**787**	937	1 113	1 007	986

For the natural resources segment, about 85 percent of the capital and exploration expenditures in 2006 was focused on growth opportunities. Significant expenditures during the year were made to ongoing development drilling at Cold Lake and to Syncrude for the company's share of the Stage 3 upgrader expansion project. Sustained operation of the upgrader expansion project began in August 2006, following a prolonged start-up period.

Other 2006 investment included drilling at conventional fields in Western Canada, advancing the Mackenzie gas and Kearl oil sands projects, and exploration off the East Coast of Canada.

The Mackenzie gas project is facing significant cost and schedule pressures brought on by unprecedented global demands for energy infrastructure. There are also uncertainties related to the regulatory and permitting process and the remaining benefits and access agreements. The company's current work efforts are focused on completing regulatory hearings, advancing approval of permits, finalizing remaining benefits and access agreements, establishing an appropriate fiscal framework with the federal government, advancing potential shipping agreements and continuing paced engineering, technical and cost-reduction efforts.

Regulatory hearings by the joint federal and provincial review panel on the Kearl oil sands project were completed in November 2006 and a decision is expected in early 2007. The company's current efforts are focused on design optimization to improve project economics and reduce project execution risk. Once this work is completed and a regulatory decision is received, project timing will be determined.

Drilling of a wildcat exploration well began with co-venturers in the Orphan Basin, a frontier basin located off the East Coast of Newfoundland. Two more exploration wells are planned by the end of 2008. Imperial holds a 15-percent interest in eight deepwater exploration licences in the basin.

Planned capital and exploration expenditures in natural resources are expected to be about $700 million in 2007, with over 75 percent of the total focused on growth opportunities. Investments are mainly planned for development drilling at Cold Lake and conventional oil and gas operations in Western Canada, facilities improvement at Syncrude, the Mackenzie gas project, the Kearl oil sands project and exploration off the East Coast.

The following table shows the company's capital expenditures in the petroleum products segment during the five years ending December 31, 2006:

millions of dollars	**2006**	2005	2004	2003	2002
Marketing	**97**	91	85	91	133
Refining and supply	**248**	368	178	369	399
Other (a)	**16**	19	20	18	57
Total capital expenditures	**361**	478	283	478	589

(a) Consists primarily of real estate purchases.

For the petroleum products segment, capital expenditures were $361 million in 2006, compared with $478 million in 2005 (2004 – $283 million). The company invested about $95 million in refining operations and other facilities during the year as part of a three-year, $500-million project to reduce sulphur content in diesel. The project was completed in 2006 and the company was able to fully meet all new government regulations on ultra-low sulphur diesel from all of its facilities across Canada by the required schedules. More than $150 million was invested in other refinery projects to improve energy efficiency and increase yield. Major investments were also made to upgrade the network of Esso service stations during the year.

Capital expenditures for the petroleum products segment in 2007 are expected to be about $250 million. Major items include additional investment in the refineries on improving energy efficiencies and increasing yield and continued enhancements to the company's retail network.

The following table shows the company's capital expenditures for its chemicals operations during the five years ending December 31, 2006:

millions of dollars	**2006**	2005	2004	2003	2002
Capital expenditures	**13**	19	15	41	25

Of the capital expenditures for chemicals in 2006, the major investment focused on improving energy efficiency and yields.

Planned capital expenditures for chemicals in 2007 will be about $15 million.

Total capital and exploration expenditures for the company in 2007, which will focus mainly on growth and productivity improvements, are expected to total about $1 billion and will be financed from internally generated funds.

Cash flow from financing activities

In June, the company renewed the normal course issuer bid (share-repurchase program) for another 12 months. During 2006, the company purchased about 45.5 million shares for $1,818 million (2005 – 52.5 million shares for $1,795 million). Since Imperial initiated its first share-repurchase program in 1995, the company has purchased close to 800 million shares – representing about 46 percent of the total outstanding at the start of the program – with resulting distributions to shareholders of about $10.5 billion.

The company declared dividends totalling 32 cents a share in 2006, up from 31 cents in 2005 (2004 – 29 cents). Regular annual per-share dividends paid have increased in each of the past 12 years and, since 1986, payments per share have grown by 80 percent.

Total debt outstanding at the end of 2006, excluding the company's share of equity company debt, was $1,437 million, compared with $1,439 million at the end of 2005 (2004 – $1,443 million). Debt represented 17 percent of the company's capital structure at the end of 2006, compared with 18 percent at the end of 2005 (2004 – 19 percent).

Debt-related interest incurred in 2006, before capitalization of interest, was $63 million, up from $45 million in 2005 (2004 – $37 million). The average effective interest rate on the company's debt was 4.2 percent in 2006, compared with 3.1 percent in 2005 (2004 – 2.8 percent).

Financial percentages, ratios and credit rating

	2006	2005	2004	2003	2002
Total debt as a percentage of capital (a)	**17**	18	19	21	24
Interest coverage ratios					
Earnings basis (b)	**66**	88	83	64	46
Cash-flow basis (c)	**77**	101	108	80	63
Long-term unsecured debt rating					
Local currency (DBRS/S&P) (d)	**AA/AAA**	AA/AAA	AA/AAA	AA/AAA	AA/AAA

(a) Current and long-term portions of debt (page 38), divided by debt and shareholders' equity (page 38).
(b) Net income (page 36), debt-related interest before capitalization (page 56, note 14) and income taxes (page 36) divided by debt-related interest before capitalization.
(c) Cash flow from net income adjusted for other non-cash items (page 37), current income tax expense (page 46, note 5) and debt-related interest before capitalization (page 56, note 14) divided by debt-related interest before capitalization.
(d) Dominion Bond Rating Service (DBRS) and Standard & Poor's Corporation (S&P) are debt-rating agencies.

The company's financial strength, as evidenced by the above financial ratios, represents a competitive advantage of strategic importance. The company's sound financial position gives it the opportunity to access capital markets in the full range of market conditions and enables the company to take on large, long-term capital commitments in the pursuit of maximizing shareholder value.

Effective May 23, 2006, the issued common shares of the company were split on a three-for-one basis and the number of authorized shares was increased from 450 million to 1,100 million. The prior period number of shares outstanding and shares purchased, as well as net income and dividends per share, have been adjusted to reflect the three-for-one split.

Contractual obligations

The following table shows the company's contractual obligations outstanding at December 31, 2006. It provides data for easy reference from the consolidated balance sheet and from individual notes to the consolidated financial statements.

millions of dollars	Financial Statement note reference	Payment due by period 2007	2008 to 2011	2012 and beyond	Total amount
Long-term debt and capital leases (a)	Note 4	907	332	27	1 266
Operating leases (b)	Note 11	53	172	48	273
Unconditional purchase obligations (c)	Note 11	58	167	40	265
Firm capital commitments (d)	Note 11	149	29	–	178
Pension and other post-retirement obligations (e)	Note 6	226	173	669	1 068
Asset retirement obligations (f)	Note 7	52	282	88	422
Other long-term agreements (g)	Note 11	271	677	240	1 188

(a) Includes capitalized lease obligations. Long-term debt amounts exclude the company's share of equity company debt.
(b) Minimum commitments for operating leases, shown on an undiscounted basis, primarily cover office buildings, rail cars and service stations.
(c) Unconditional purchase obligations mainly pertain to pipeline throughput agreements.
(d) Firm capital commitments related to capital projects, shown on an undiscounted basis. The largest commitment outstanding at year-end 2006 was $41 million associated with the company's share of capital projects at Syncrude.
(e) The amount by which the projected benefit obligations exceeded the fair value of fund assets for pension and other post-retirement plans at year-end. The payments by period include expected contributions to funded pension plans in 2007 and estimated benefit payments for unfunded plans in all years.
(f) Asset retirement obligations represent the discounted present value of legal obligations associated with site restoration on the retirement of assets with determinable useful lives.
(g) Other long-term agreements include primarily raw material supply and transportation services agreements.

The company was contingently liable at December 31, 2006, for a maximum of $87 million relating to guarantees for purchasing operating equipment and other assets from its rural marketing associates upon expiry of the associate agreement or the resignation of the associate. The company expects that the fair value of the operating equipment and other assets so purchased would cover the maximum potential amount of future payments under the guarantees.

Various lawsuits are pending against Imperial Oil Limited and its subsidiaries. Based on a consideration of all relevant facts and circumstances, the company does not believe the ultimate outcome of any currently pending lawsuits against the company will have a material, adverse effect on the company's operations or financial condition. There are no events or uncertainties known to management beyond those already included in reported financial information that would indicate a material change in future operating results or financial condition.

Recently issued Statement of Financial Accounting Standards

Accounting for uncertainty in income taxes

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48 (FIN 48), "Accounting for Uncertainty in Income Taxes". FIN 48 is an interpretation of FASB Statement No. 109 "Accounting for Income Taxes" and must be adopted by the company no later than January 1, 2007. The interpretation prescribes a comprehensive model for recognizing, measuring, presenting and disclosing in the financial statements uncertain tax positions that the company has taken or expects to take in its tax returns. The new standard requires that a tax benefit be recognized in the books only if it is more likely than not that a tax position will be sustained. Otherwise, a liability will need to be recorded to reflect the difference between the as-filed tax basis and the book tax basis. The new standard does not allow a restatement of the comparative prior periods.

The company expects to recognize a transition gain of approximately $14 million in shareholders' equity upon adoption of FIN 48 in the first quarter of 2007. This gain reflects the recognition of several refund claims and associated interest, partly offset by increased liability reserves.

Critical accounting policies

The company's financial statements have been prepared in accordance with United States generally accepted accounting principles (GAAP) and include estimates that reflect management's best judgment. The company's accounting and financial reporting fairly reflect its straightforward business model. Imperial does not use financing structures for the purpose of altering accounting outcomes or removing debt from the balance sheet. The following summary provides further information about the critical accounting policies and the estimates that are made by the company to apply those policies. It should be read in conjunction with note 1 to the consolidated financial statements on page 40.

Hydrocarbon reserves

Proved oil, gas and synthetic crude oil reserve quantities are used as the basis of calculating unit-of-production rates for depreciation and evaluating for impairment. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs and deposits under existing economic and operating conditions. Estimates of synthetic crude oil reserves are based on detailed geological and engineering assessments of in-place crude bitumen volume, the mining plan, historical extraction recovery and upgrading yield factors, installed plant operating capacity and operating approval limits.

The estimation of proved reserves is controlled by the company through long-standing approval guidelines. Reserve changes are made with a well-established, disciplined process driven by senior-level geoscience and engineering professionals (assisted by a central reserves group with significant technical experience), culminating in reviews with and approval by senior management and the company's board of directors. Notably, the company does not use specific quantitative reserve targets to determine compensation. Key features of the estimation include rigorous peer-reviewed technical evaluations and analysis of well and field performance information and a requirement that management make significant funding commitment toward the development of the reserves prior to booking.

Although the company is reasonably certain that proved reserves will be produced, the timing and amount recovered can be affected by a number of factors, including completion of development projects, reservoir performance and significant changes in long-term oil and gas price levels.

Beginning in 2004, the year-end reserves volumes as well as the reserves change categories shown in the proved reserves tables are calculated using December 31 prices and costs. These reserves quantities are also used in calculating unit-of-production depreciation rates and in calculating the standardized measure of discounted net cash flow. The United States Securities and Exchange Commission regulations preclude the company from showing in the Financial section of this document the reserves that are calculated in a manner which is consistent with the basis that the company uses to make its investment decisions. The use of year-end prices for reserves estimation introduces short-term price volatility into the process since annual adjustments are required based on prices occurring on a single day. The company believes that this approach is inconsistent with the long-term nature of the natural resources business where production from individual projects often spans multiple decades. The use of prices from a single date is not relevant to the investment decisions made by the company, and annual variations in reserves based on such year-end prices are not of consequence to how the business is actually managed.

Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the evaluation or revaluation of already available geologic, reservoir or production data; new geologic, reservoir or production data; or changes in year-end prices and costs that are used in the determination of reserves. This category can also include changes associated with the performance of improved recovery projects and significant changes in either development strategy or production equipment/facility capacity.

The company uses the successful-efforts method to account for its exploration and production activities. Under this method, costs are accumulated on a field-by-field basis with certain exploratory expenditures and exploratory dry holes being expensed as incurred. Costs of productive wells and development dry holes are capitalized and amortized on the unit-of-production method for each field. The company uses this accounting policy instead of the full-cost method because it provides a more timely accounting of the success or failure of the company's exploration and production activities.

Impact of reserves on depreciation

The calculation of unit-of-production depreciation is a critical accounting estimate that measures the depreciation of natural resources assets. It is the ratio of actual volumes produced to total proved developed reserves (those reserves recoverable through existing wells with existing equipment and operating methods) applied to the asset cost. The volumes produced and asset cost are known and, while proved developed reserves have a high probability of recoverability, they are based on estimates that are subject to some variability. While the revisions the company has made in the past are an indicator of variability, they have had little impact on the unit-of-production rates of depreciation.

Impact of reserves and prices on testing for impairment

Proved oil and gas properties held and used by the company are reviewed for impairment whenever events or circumstances indicate that the carrying amounts may not be recoverable. Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets.

The company estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. In general, impairment analyses are based on proved reserves. Where probable reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the impairment evaluation. An asset would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount by which the asset's carrying value exceeds its fair value.

The impairment evaluation triggers include a significant decrease in current and projected prices or reserve volumes, an accumulation of project costs significantly in excess of the amount originally expected and historical and current operating losses.

In general, the company does not view temporarily low oil and gas prices as a triggering event for conducting impairment tests. The markets for crude oil and natural gas have a history of significant price volatility. Although prices will occasionally drop significantly, industry prices over the long term will continue to be driven by market supply and demand. Accordingly, any impairment tests that the company performs make use of the company's price assumptions developed in the annual planning and budgeting process for the crude oil and natural gas markets, petroleum products and chemicals. These are the same price assumptions that are used for capital investment decisions. The corporate plan is a fundamental annual management process that is the basis for setting near-term risk assessed operating and capital objectives in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Any impairment tests that the company performs also make use of annual volumes based on individual field production profiles, which are also updated as part of the annual plan process.

The standardized measure of discounted future cash flows on page 59 is based on the year-end 2006 price applied for all future years, as required under Statement of Financial Accounting Standards No. 69 (SFAS 69). Future prices used for any impairment tests will vary from the one used in the SFAS 69 disclosure and could be lower or higher for any given year.

Pension benefits

The company's pension plan is managed in compliance with the requirements of governmental authorities and meets funding levels as determined by independent third-party actuaries. Pension accounting requires explicit assumptions regarding, among others, the discount rate for the benefit obligations, the expected rate of return on plan assets and the long-term rate of future compensation increases. All pension assumptions are reviewed annually by senior management. These assumptions are adjusted only as appropriate to reflect long-term changes in market rates and outlook. The long-term expected rate of return on plan assets of 8.25 percent used in 2006 compares to actual returns of 9.82 percent and 9.99 percent achieved over the last 10- and 20-year periods ending December 31, 2006. If different assumptions are used, the expense and obligations could increase or decrease as a result. The company's potential exposure to changes in assumptions is summarized in note 6 to the consolidated financial statements on page 47. At Imperial, differences between actual returns on plan assets versus long-term expected returns are not recorded in pension expense in the year the differences occur, but rather are amortized in pension expense as permitted by GAAP, along with other actuarial gains and losses, over the expected remaining service life of employees. Pension expense represented less than one percent of total expenses in 2006.

Asset retirement obligations and other environmental liabilities

Legal obligations associated with site restoration on the retirement of assets with determinable useful lives are recognized when they are incurred, which is typically at the time the assets are installed. The obligations are initially measured at fair value and discounted to present value. Over time, the discounted asset retirement obligation amount will be accreted for the change in its present value, with this effect included in operating expense. As payments to settle the obligations occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 25 years, the discount rate will be adjusted only as appropriate to reflect long-term changes in market rates and outlook. For 2006, the obligations were discounted at six percent and the accretion expense was $22 million, before tax, which was significantly less than one percent of total expenses in the year. There would be no material impact on the company's reported financial results if a different discount rate had been used.

Asset retirement obligations are not recognized for assets with an indeterminate useful life. Asset retirement obligations for these facilities generally become firm at the time the facilities are permanently shut down and dismantled. These obligations may include the costs of asset disposal and additional soil remediation. However, these sites have indeterminate lives based on plans for continued operations, and as such, the fair value of the conditional legal obligations cannot be measured, since it is impossible to estimate the future settlement dates of such obligations. For these and non-operating assets, the company accrues provisions for environmental liabilities when it is probable that obligations have been incurred and the amount can be reasonably estimated.

Asset retirement obligations and other environmental liabilities are based on engineering estimated costs, taking into account the anticipated method and extent of remediation consistent with legal requirements, current technology and the possible use of the location. Since these estimates are specific to the locations involved, there are many individual assumptions underlying the company's total asset retirement obligations and provision for other environmental liabilities. While these individual assumptions can be subject to change, none of them is individually significant to the company's reported financial results.

Market risks and other uncertainties

The company is exposed to a variety of financial, operating and market risks in the course of its business. Some of these risks are within the company's control, while others are not. For those risks that can be controlled, specific risk-management strategies are employed to reduce the likelihood of loss.

In October 2006, the Government of Canada indicated its intent to introduce regulations to control greenhouse-gas emissions from major industrial facilities, although details of what measures will be imposed on companies have not been determined. Consequently, attempts to assess the impact on Imperial can only be speculative. The company will continue to monitor the development of legal requirements in this area.

Other risks, such as changes in international commodity prices and currency-exchange rates, are beyond the company's control. The company's size, strong financial position and the complementary nature of its natural resources, petroleum products and chemicals segments help mitigate the company's exposure to changes in these other risks. The company's potential exposure to these types of risks is summarized in the earnings sensitivity table below.

The company does not use derivative markets to speculate on the future direction of currency or commodity prices and does not sell forward any part of production from any business segment.

The following table shows the estimated annual effect, under current conditions, of certain sensitivities of the company's after-tax net income.

Earnings sensitivities (a)

millions of dollars after tax

Six dollars (U.S.) a barrel change in crude oil prices	+ (–)	$ 270
Ninety cents a thousand cubic feet change in natural gas prices	+ (–)	$ 27
One cent (U.S.) a litre change in sales margins for total petroleum products	+ (–)	$ 175
One cent (U.S.) a pound change in sales margins for polyethylene	+ (–)	$ 7
One-quarter percent decrease (increase) in short-term interest rates	+ (–)	$ 2
Nine cents decrease (increase) in the value of the Canadian dollar versus the U.S. dollar	+ (–)	$ 400

(a) The amount quoted to illustrate the impact of each sensitivity represents a change of about 10 percent in the value of the commodity or rate in question at the end of 2006. Each sensitivity calculation shows the impact on net income that results from a change in one factor, after tax and royalties and holding all other factors constant. While these sensitivities are applicable under current conditions, they may not apply proportionately to larger fluctuations.

The sensitivity of net income to changes in the Canadian dollar versus the U.S. dollar decreased from year-end 2005 by about $8 million (after tax) a year for each one-cent change, primarily due to the decrease in industry refining margins.

The sensitivity to changes in natural gas prices decreased from 2005 year-end by about $3 million (after tax) for each 10-cent change, primarily due to the company's lower natural gas production.

Frequently used financial terms

Listed below are definitions of four of Imperial's frequently used financial performance measures. The definitions are provided to facilitate understanding of the terms and how they are calculated.

Capital employed

Capital employed is a measure of net investment. When viewed from the perspective of how capital is used by the business, it includes the company's property, plant and equipment and other assets, less liabilities, excluding both short-term and long-term debt. When viewed from the perspective of the sources of capital employed for the whole company, it includes total debt and shareholders' equity. Both of these views include the company's share of amounts applicable to equity companies.

millions of dollars	**2006**	2005	2004
Business uses: asset and liability perspective			
Total assets	**16 141**	15 582	14 027
Less: total current liabilities, excluding short-term debt and current portion of long-term debt	**(4 270)**	(4 569)	(3 582)
Less: total long-term liabilities, excluding long-term debt	**(3 028)**	(2 941)	(2 680)
Add: Imperial's share of equity company debt	**55**	59	56
Total capital employed	**8 898**	8 131	7 821

millions of dollars	**2006**	2005	2004
Total company sources: debt and equity perspective			
Short-term debt and current portion of long-term debt	**1 078**	576	1 076
Long-term debt	**359**	863	367
Shareholders' equity	**7 406**	6 633	6 322
Add: Imperial's share of equity company debt	**55**	59	56
Total capital employed	**8 898**	8 131	7 821

Return on average capital employed (ROCE)

ROCE is a financial performance ratio. For each of the company's business segments, ROCE is annual business-segment net income divided by average business-segment capital employed (an average of the beginning- and end-of-year amounts). Segment net income includes Imperial's share of segment net income of equity companies, consistent with the definition used for capital employed, and excludes the cost of financing. The company's total ROCE is net income excluding the after-tax cost of financing divided by total average capital employed. The company has consistently applied its ROCE definition for many years and views it as the best measure of historical capital productivity in a capital-intensive, long-term industry to both evaluate management's performance and demonstrate to shareholders that capital has been used wisely over the long term. Additional measures, which tend to be more cash flow based, are used for future investment decisions.

millions of dollars	**2006**	2005	2004
Net income	**3 044**	2 600	2 052
Financing costs (after tax), including Imperial's share of equity companies	**10**	3	3
Net income, excluding financing costs	**3 054**	2 603	2 055
Average capital employed	**8 515**	7 976	7 425
Return on average capital employed (percent)	**35.9**	32.6	27.7

Operating costs

Operating costs are the combined total of production, manufacturing, selling, general, exploration, depreciation and depletion expenses from the consolidated statement of income and Imperial's share of similar costs for equity companies. Operating costs are the costs incurred during the period to produce, manufacture and otherwise prepare the company's products for sale – including energy costs, staffing, maintenance and other costs to explore for and produce oil and gas and operate refining and chemical plants. Delivery costs to customers and marketing expenses are also included. Operating costs exclude the cost of raw materials and those costs incurred in bringing inventory to its existing condition and final storage prior to delivery to a customer. These expenses are on a before-tax basis. While Imperial's management is responsible for all revenue and expense elements of net income, operating costs, as defined below, represent the expenses most directly under management's control.

millions of dollars	**2006**	2005	2004
Expenses (from page 36)			
Exploration	**32**	43	59
Production and manufacturing	**3 446**	3 327	2 820
Selling and general	**1 284**	1 577	1 281
Depreciation and depletion	**831**	895	908
Subtotal	**5 593**	5 842	5 068
Imperial's share of equity company expenses	**60**	56	52
Total operating costs	**5 653**	5 898	5 120

Cash flow from operating activities and asset sales

Cash flow from operating activities and asset sales is the sum of the net cash provided by operating activities and proceeds from asset sales reported in the consolidated statement of cash flows. This cash flow is the total source of cash both from operating the company's assets and from the divesting of assets. The company employs a long-standing, disciplined regular review process to ensure that all assets are contributing to the company's strategic and financial objectives. Assets are divested when they no longer meet these objectives or are worth considerably more to others. Because of the regular nature of this activity, management believes it is useful for investors to consider sales proceeds together with cash provided by operating activities when evaluating cash available for investment in the business and financing activities, including shareholder distributions.

millions of dollars	**2006**	2005	2004
Cash from operating activities	**3 587**	3 451	3 312
Proceeds from asset sales	**212**	440	102
Total cash flow from operating activities and asset sales	**3 799**	3 891	3 414

Management's report on internal control over financial reporting

Management, including the company's chief executive officer, and principal accounting officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over the company's financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Imperial Oil Limited's internal control over financial reporting was effective as of December 31, 2006.

Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2006, was audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

T.J. Hearn

Chairman, president and chief executive officer

P.A. Smith

Controller and senior vice-president,
finance and administration
(Principal accounting officer and principal financial officer)

February 27, 2007

To the Shareholders of Imperial Oil Limited

We have completed integrated audits of Imperial Oil Limited's consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, shareholders' equity and cash flows present fairly, in all material respects, the financial position of Imperial Oil Limited and its subsidiaries at 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 accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements 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 the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statements presentation. We believe that our audits provide a reasonable basis for our opinion.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that 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 (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider 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 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

PricewaterhouseCoopers LLP.

Chartered Accountants

Calgary, Alberta, Canada
February 27, 2007

Consolidated statement of income (U.S. GAAP)

millions of Canadian dollars For the years ended December 31	**2006**	2005	2004
Revenues and other income			
Operating revenues (a)(b)(c)	**24 505**	27 797	22 408
Investment and other income (note 10)(d)	**283**	417	52
Total revenues and other income	**24 788**	28 214	22 460
Expenses			
Exploration	**32**	43	59
Purchases of crude oil and products (b)(e)	**13 793**	17 168	13 094
Production and manufacturing (f)	**3 446**	3 327	2 820
Selling and general	**1 284**	1 577	1 281
Federal excise tax (a)	**1 274**	1 278	1 264
Depreciation and depletion	**831**	895	908
Financing costs (note 14)(g)	**28**	8	7
Total expenses	**20 688**	24 296	19 433
Income before income taxes	**4 100**	3 918	3 027
Income taxes (note 5)	**1 056**	1 318	975
Net income	**3 044**	2 600	2 052
Per-share information (Canadian dollars)			
Net income per common share – basic (note 12)	**3.12**	2.54	1.92
Net income per common share – diluted (note 12)	**3.11**	2.53	1.91
Dividends	**0.32**	0.31	0.29

(a) Operating revenues include federal excise tax of $1,274 million (2005 – $1,278 million, 2004 – $1,264 million).

(b) Amounts included in operating revenues for purchase/sale contracts with the same counterparty (associated costs are included in purchases of crude oil and products resulting in no impact to net income) are nil (2005 – $4,894 million, 2004 – $3,584 million), (note 1).

(c) Operating revenues include amounts from related parties of $1,927 million (2005 – $1,325 million, 2004 – $1,142 million), (note 15).

(d) Investment and other income include amounts from related parties of $31 million (2005 – $24 million, 2004 – $23 million), (note 15).

(e) Purchases of crude oil and products include amounts from related parties of $4,119 million (2005 – $3,650 million, 2004 – $3,169 million), (note 15).

(f) Production and manufacturing expenses include amounts to related parties of $219 million (2005 – $175 million, 2004 – $43 million), (note 15).

(g) Financing costs include amounts to related parties of $33 million (2005 – $22 million, 2004 – $20 million), (note 15).

The information on pages 40 through 57 is an integral part of these consolidated financial statements.

millions of Canadian dollars Inflow/(outflow) For the years ended December 31	**2006**	2005	2004
Operating activities			
Net income	**3 044**	2 600	2 052
Adjustments for non-cash items:			
Depreciation and depletion	**831**	895	908
(Gain)/loss on asset sales, after tax	**(96)**	(233)	(32)
Deferred income taxes and other	**254**	(116)	(90)
Changes in operating assets and liabilities:			
Accounts receivable	**203**	(414)	(311)
Inventories and prepaids	**(97)**	(67)	(32)
Income taxes payable	**(225)**	304	462
Accounts payable	**(86)**	644	308
All other items – net (a)	**(241)**	(162)	47
Cash from operating activities	**3 587**	3 451	3 312
Investing activities			
Additions to property, plant and equipment and intangibles	**(1 177)**	(1 432)	(1 376)
Proceeds from asset sales	**212**	440	102
Loans to equity company	**–**	–	(32)
Cash from (used in) investing activities	**(965)**	(992)	(1 306)
Financing activities			
Short-term debt – net	**72**	18	9
Repayment of long-term debt	**(74)**	(21)	(8)
Issuance of common shares under stock option plan	**10**	38	13
Common shares purchased (note 12)	**(1 818)**	(1 795)	(872)
Dividends paid	**(315)**	(317)	(317)
Cash from (used in) financing activities	**(2 125)**	(2 077)	(1 175)
Increase (decrease) in cash	**497**	382	831
Cash at beginning of year	**1 661**	1 279	448
Cash at end of year (b)	**2 158**	1 661	1 279

(a) Includes contribution to registered pension plans of $395 million (2005 – $350 million, 2004 – $114 million).

(b) Cash is composed of cash in bank and cash equivalents at cost. Cash equivalents are all highly liquid securities with maturity of three months or less when purchased.

The information on pages 40 through 57 is an integral part of these consolidated financial statements.

Consolidated balance sheet (U.S. GAAP)

millions of Canadian dollars At December 31	2006	2005
Assets		
Current assets		
Cash	**2 158**	1 661
Accounts receivable, less estimated doubtful amounts	**1 871**	2 073
Inventories of crude oil and products (note 13)	**556**	481
Materials, supplies and prepaid expenses	**151**	130
Deferred income tax assets (note 5)	**573**	654
Total current assets	**5 309**	4 999
Investments and other long-term assets	**104**	94
Property, plant and equipment,		
less accumulated depreciation and depletion (note 3)	**10 457**	10 132
Goodwill (note 3)	**204**	204
Other intangible assets, net	**67**	153
Total assets (note 3)	**16 141**	15 582
Liabilities		
Current liabilities		
Short-term debt	**171**	99
Accounts payable and accrued liabilities (a)	**3 080**	3 170
Income taxes payable	**1 190**	1 399
Current portion of long-term debt (b)	**907**	477
Total current liabilities	**5 348**	5 145
Long-term debt (note 4)(c)	**359**	863
Other long-term obligations (note 7)	**1 683**	1 728
Deferred income tax liabilities (note 5)	**1 345**	1 213
Commitments and contingent liabilities (note 11)		
Total liabilities	**8 735**	8 949
Shareholders' equity		
Common shares at stated value (note 12)(d)	**1 677**	1 747
Earnings reinvested	**6 462**	5 466
Accumulated other nonowner changes in equity	**(733)**	(580)
Total shareholders' equity	**7 406**	6 633
Total liabilities and shareholders' equity	**16 141**	15 582

(a) Accounts payable and accrued liabilities include amounts to related parties of $151 million (2005 – $224 million), (note 15).
(b) Current portion of long-term debt includes amounts to related parties of $500 million (2005 – nil), (note 4).
(c) Long-term debt includes amounts to related parties of $318 million (2005 – $818 million), (note 4).
(d) Number of common shares outstanding was 953 million (2005 – 998 million), (note 12).

The information on pages 40 through 57 is an integral part of these consolidated financial statements.

Approved by the directors

T.J. Hearn

Chairman, president and chief executive officer

P.A. Smith

Controller and senior vice-president, finance and administration

millions of Canadian dollars At December 31	2006	2005	2004
Common shares at stated value (note 12)			
At beginning of year	**1 747**	1 801	1 859
Issued under the stock option plan	**10**	38	13
Share purchases at stated value	**(80)**	(92)	(71)
At end of year	**1 677**	1 747	1 801
Earnings reinvested			
At beginning of year	**5 466**	4 889	3 952
Net income for the year	**3 044**	2 600	2 052
Share purchases in excess of stated value	**(1 737)**	(1 703)	(801)
Dividends	**(311)**	(320)	(314)
At end of year	**6 462**	5 466	4 889
Accumulated other nonowner changes in equity			
At beginning of year	**(580)**	(368)	(266)
Minimum pension liability adjustment (note 6)	**580**	(212)	(102)
Post-retirement benefit liability adjustment (note 6)	**(733)**	–	–
At end of year	**(733)**	(580)	(368)
Shareholders' equity at end of year	**7 406**	6 633	6 322
Nonowner changes in equity for the year			
Net income for the year	**3 044**	2 600	2 052
Other nonowner changes in equity			
Minimum pension liability adjustment	**580**	(212)	(102)
Post-retirement benefit liability adjustment	**(733)**	–	–
Total nonowner changes in equity for the year	**2 891**	2 388	1 950

The information on pages 40 through 57 is an integral part of these consolidated financial statements.

1. Summary of significant accounting policies

The company's principal business is energy, involving the exploration, production, transportation and sale of crude oil and natural gas and the manufacture, transportation and sale of petroleum products. The company is also a major manufacturer and marketer of petrochemicals.

The consolidated financial statements have been prepared in accordance with generally accepted accounting principles (GAAP) in the United States of America. The financial statements include certain estimates that reflect management's best judgment. Certain reclassifications to prior years have been made to conform to the 2006 presentation. All amounts are in Canadian dollars unless otherwise indicated.

Principles of consolidation

The consolidated financial statements include the accounts of Imperial Oil Limited and its subsidiaries. Intercompany accounts and transactions are eliminated. Subsidiaries include those companies in which Imperial has both an equity interest and the continuing ability to unilaterally determine strategic, operating, investing and financing policies. Significant subsidiaries included in the consolidated financial statements include Imperial Oil Resources Limited, Imperial Oil Resources N.W.T. Limited, Imperial Oil Resources Ventures Limited and McColl-Frontenac Petroleum Inc. All of the above companies are wholly owned. A significant portion of the company's activities in natural resources is conducted jointly with other companies. The accounts reflect the company's share of undivided interest in such activities, including its 25 percent interest in the Syncrude joint venture and its nine percent interest in the Sable offshore energy project.

Inventories

Inventories are recorded at the lower of cost or net realizable value. The cost of crude oil and products is determined primarily using the last-in, first-out (LIFO) method. LIFO was selected over the alternative first-in, first-out and average cost methods because it provides a better matching of current costs with the revenues generated in the period.

Inventory costs include expenditures and other charges, including depreciation, directly or indirectly incurred in bringing the inventory to its existing condition and final storage prior to delivery to a customer. Selling and general expenses are reported as period costs and excluded from inventory costs.

Investments

The principal investments in companies other than subsidiaries are accounted for using the equity method. They are recorded at the original cost of the investment plus Imperial's share of earnings since the investment was made, less dividends received. Imperial's share of the after-tax earnings of these companies is included in "investment and other income" in the consolidated statement of income. Other investments are recorded at cost. Dividends from these other investments are included in "investment and other income."

These investments represent interests in non-publicly traded pipeline companies that facilitate the sale and purchase of crude oil and natural gas in the conduct of company operations. Other parties who also have an equity interest in these companies share in the risks and rewards according to their percentage of ownership. Imperial does not invest in these companies in order to remove liabilities from its balance sheet.

Property, plant and equipment

Property, plant and equipment are recorded at cost. Investment tax credits and other similar grants are treated as a reduction of the capitalized cost of the asset to which they apply.

The company uses the successful-efforts method to account for its exploration and development activities. Under this method, costs are accumulated on a field-by-field basis with certain exploratory expenditures and exploratory dry holes being expensed as incurred. The company carries as an asset exploratory well costs if (a) the well found a sufficient quantity of reserves to justify its completion as a producing well and (b) the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria were charged to expense. Costs of productive wells and development dry holes are capitalized and amortized on the unit-of-production method for each field. The company uses this accounting policy instead of the full-cost method because it provides a more timely accounting of the success or failure of the company's exploration and production activities.

Maintenance and repair costs, including planned major maintenance, are expensed as incurred. Improvements that increase or prolong the service life or capacity of an asset are capitalized.

Production costs are expensed as incurred. Production involves lifting the oil and gas to the surface and gathering, treating, field processing and field storage of the oil and gas. The production function normally terminates at the outlet valve on the lease or field production storage tank. Production costs are those incurred to operate and maintain the company's wells and related equipment and facilities. They become part of the cost of oil and gas produced. These costs, sometimes referred to as lifting costs, include such items as labour cost to operate the wells and related equipment; repair and maintenance costs on the wells and equipment; materials, supplies and energy costs required to operate the wells and related equipment; and administrative expenses related to the production activity.

Depreciation and depletion for assets associated with producing properties begin at the time when production commences on a regular basis. Depreciation for other assets begins when the asset is in place and ready for its intended use. Assets under construction are not depreciated or depleted. Acquisition costs of proved properties are amortized using a unit-of-production method, computed on the basis of total proved oil and gas reserves. Unit-of-production depreciation is applied to those wells, plant and equipment assets associated with productive depletable properties and the unit-of-production rates are based on the amount of proved developed reserves of oil and gas. Depreciation of other plant and equipment is calculated using the straight-line method, based on the estimated service life of the asset. In general, refineries are depreciated over 25 years; other major assets, including chemical plants and service stations, are depreciated over 20 years.

Proved oil and gas properties held and used by the company are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets.

The company estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. Cash flows used in impairment evaluations are developed using annually updated corporate plan investment evaluation assumptions for crude oil commodity prices and foreign-currency exchange rates. Annual volumes are based on individual field production profiles, which are also updated annually. Prices for natural gas and other products sold under contract are based on corporate plan assumptions developed annually by major contracts and also for investment evaluation purposes.

In general, impairment analyses are based on proved reserves. Where probable reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the impairment evaluation. An asset would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount by which the carrying value exceeds its fair value.

Acquisition costs for the company's oil sands (a) operation are capitalized as incurred. Oil sands exploration costs are expensed as incurred. The capitalization of project development costs begins when there are no major uncertainties that exist which would preclude management from making a significant funding commitment within a reasonable time period. The company expenses stripping costs during the production phase as incurred.

Depreciation of oil sands assets begins at the time when production commences on a regular basis. Assets under construction are not depreciated. Investments in extraction facilities, which separate the crude from sand, as well as the upgrading facilities, are depreciated on a unit-of-production method based on proven developed reserves. Investments in mining and transportation systems are generally depreciated on a straight-line basis over a 15-year life.

Oil sands assets held and used by the company are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amounts are not recoverable. The impairment evaluation for oil sands assets is based on a comparison of undiscounted cash flows to book carrying value.

Gains or losses on assets sold are included in "investment and other income" in the consolidated statement of income.

Interest capitalization

Interest costs relating to major capital projects under construction are capitalized as part of property, plant and equipment. The project construction phase commences with the development of the detailed engineering design and ends when the constructed assets are ready for their intended use.

Goodwill and other intangible assets

Goodwill is not subject to amortization. Goodwill is tested for impairment annually or more frequently if events or circumstances indicate it might be impaired. Impairment losses are recognized in current period earnings. The evaluation for impairment of goodwill is based on a comparison of the carrying values of goodwill and associated operating assets with the estimated present value of net cash flows from those operating assets.

Intangible assets with determinable useful lives are amortized over the estimated service lives of the assets. Computer software development costs are amortized over a maximum of 15 years and customer lists are amortized over a maximum of 10 years. The amortization is included in "depreciation and depletion" in the consolidated statement of income.

(a) Oil sands are a semi-solid material composed of bitumen, sand, water and clays, which are recovered through surface mining methods. Currently, the company's oil sands production volumes and reserves are the company's share of production volumes and reserves in the Syncrude joint venture.

Asset retirement obligations and other environmental liabilities

Legal obligations associated with site restoration on the retirement of assets with determinable useful lives are recognized when they are incurred, which is typically at the time the assets are installed. These obligations primarily relate to soil remediation and decommissioning and removal costs of oil and gas wells and related facilities. The obligations are initially measured at fair value and discounted to present value. A corresponding amount equal to that of the initial obligation is added to the capitalized costs of the related asset. Over time, the discounted asset retirement obligation amount will be accreted for the change in its present value, and the initial capitalized costs will be depreciated over the useful lives of the related assets.

No asset retirement obligations are set up for those manufacturing, distribution and marketing facilities with an indeterminate useful life. Asset retirement obligations for these facilities generally become firm at the time the facilities are permanently shut down and dismantled. These obligations may include the costs of asset disposal and additional soil remediation. However, these sites have indeterminate lives based on plans for continued operations, and as such, the fair value of the conditional legal obligations cannot be measured, since it is impossible to estimate the future settlement dates of such obligations. Provision for environmental liabilities of these assets is made when it is probable that obligations have been incurred and the amount can be reasonably estimated. These liabilities are not discounted. Asset retirement obligations and other provisions for environmental liabilities are determined based on engineering estimated costs, taking into account the anticipated method and extent of remediation consistent with legal requirements, current technology and the possible use of the location.

Foreign-currency translation

Monetary assets and liabilities in foreign currencies have been translated at the rates of exchange prevailing on December 31. Any exchange gains or losses are recognized in income.

Financial instruments

The fair values of cash, accounts receivable and current liabilities approximate recorded amounts because of the short period to receipt or payment of cash. The fair value of the company's long-term debt is estimated based on quoted market prices for the same or similar issues or on the current rates offered to the company for debt of the same duration to maturity. The fair values of the company's other financial instruments, which are mainly long-term receivables, are estimated primarily by discounting future cash flows, using current rates for similar financial instruments under similar credit risk and maturity conditions.

The company does not use financing structures for the purpose of altering accounting outcomes or removing debt from the balance sheet. The company does not use derivative instruments to speculate on the future direction of currency or commodity prices and does not sell forward any part of production from any business segment.

Revenues

Revenues associated with sales of crude oil, natural gas, petroleum and chemical products and other items are recorded when the products are delivered. Delivery occurs when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable and collectibility is reasonably assured. The company does not enter into ongoing arrangements whereby it is required to repurchase its products, nor does the company provide the customer with a right of return.

Revenues include amounts billed to customers for shipping and handling. Shipping and handling costs incurred up to the point of final storage prior to delivery to a customer are included in "purchases of crude oil and products" in the consolidated statement of income. Delivery costs from final storage to customer are recorded as a marketing expense in "selling and general" expenses.

Effective January 1, 2006, the company adopted the Emerging Issues Task Force (EITF) consensus on Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty". The EITF concluded that purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another should be combined and recorded as exchanges measured at the book value of the item sold. In prior periods, the company recorded certain crude oil, natural gas, petroleum product and chemical sales and purchases contemporaneously negotiated with the same counterparty as revenues and purchases. As a result of the EITF consensus, beginning in 2006, the company's accounts "operating revenue" and "purchases of crude oil and products" on the consolidated statement of income have been reduced by associated amounts with no impact on net income. All operating segments are affected by this change, with the largest impact in the petroleum products segment.

Share-based compensation

Effective January 1, 2006, the company adopted the Financial Accounting Standards Board's (FASB) revised Statement of Financial Accounting Standards No. 123 (SFAS 123R), "Share-based Payment". SFAS 123R requires compensation costs related to share-based payments to be recognized in the income statement over the requisite service period. The amount of the compensation costs is to be measured based on the grant-date fair value of the instrument issued. In addition, liability awards are to be remeasured each reporting period through settlement. SFAS 123R is effective for awards granted or modified after the date of adoption and for awards granted prior to that date that have not vested. In 2003, the company adopted a policy of expensing all share-based payments that is consistent with the provisions of SFAS 123R, and all prior years outstanding stock option awards have vested. SFAS 123R does not materially change the company's existing accounting practices or the amount of share-based compensation recognized in earnings. Compensation expense related to share-based programs is recorded as "selling and general" expenses in the consolidated statement of income.

The company has recognized restricted stock awards made prior to 2006 in compensation expense using the "nominal vesting period approach". Under this method, the fair value of the awards has been amortized into compensation expense over the full vesting period of each award. The fair value is remeasured each reporting period through settlement. For awards granted after the company's adoption of SFAS 123R, compensation expense is recognized using the "non-substantive vesting period approach". Under this method, the value of the grants is amortized to compensation expense over the shorter of (a) the vesting period of each award or (b) the remaining time period until the employee becomes retiree eligible. Under both methods, the full unamortized value of awards for employees who retire before the end of the applicable amortization period is expensed. The impact of switching to the non-substantive vesting period approach is not material for the company.

As permitted by Statement of Financial Accounting Standard (SFAS) No. 123, the company continues to apply the intrinsic-value-based method of accounting for the incentive stock options granted in April 2002. Under this method, compensation expense is not recognized on the issuance of stock options, as the exercise price is equal to the market value at the date of grant. If the provisions of SFAS 123 had been adopted for all prior years, net income for 2004 would have been reduced by $2 million. The impact on net income per share on both a basic and diluted basis for 2004 was negligible. All incentive stock options have vested as of January 1, 2005.

Consumer taxes

Taxes levied on the consumer and collected by the company are excluded from the consolidated statement of income. These are primarily provincial taxes on motor fuels and the federal goods and services tax.

2. Accounting change for defined benefit post-retirement plans

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 158 (SFAS 158), "Employers' Accounting for Defined Benefit Pension and Other Post-retirement Plans, an amendment to FASB Statements No. 87, 88, 106 and 132(R)". SFAS 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit post-retirement plan as an asset or liability in its balance sheet and to recognize changes in that funded status in the year in which the changes occur through other nonowner changes in equity. The standard also requires disclosure in the notes to the financial statements of additional information, including certain effects on net periodic benefit costs of the next fiscal year that arise from delayed recognition of gains or losses and prior service costs. SFAS 158 was adopted by the company in the financial statements for the year ending December 31, 2006. See note 6, Employee retirement benefits, for further details.

3. Business segments

The company operates its business in Canada. The natural resources, petroleum products and chemicals functions best define the operating segments of the business that are reported separately. The factors used to identify these reportable segments are based on the nature of the operations that are undertaken by each segment and the structure of the company's internal organization. The natural resources segment is organized and operates to explore for and ultimately produce crude oil and its equivalent, and natural gas. The petroleum products segment is organized and operates to refine crude oil into petroleum products and the distribution and marketing of these products. The chemicals segment is organized and operates to manufacture and market hydrocarbon-based chemicals and chemical products. The above segmentation has been the long-standing practice of the company and is broadly understood across the petroleum and petrochemical industries.

These functions have been defined as the operating segments of the company because they are the segments (a) that engage in business activities from which revenues are earned and expenses are incurred; (b) whose operating results are regularly reviewed by the company's chief operating decision maker to make decisions about resources to be allocated to each segment and assess its performance; and (c) for which discrete financial information is available.

Corporate and other includes assets and liabilities that do not specifically relate to business segments – primarily cash, long-term debt and liabilities associated with incentive compensation and post-retirement benefit liability adjustment. Net income in this segment primarily includes financing costs, interest income and incentive compensation expenses.

Segment accounting policies are the same as those described in this summary of significant accounting policies. Natural resources, petroleum products and chemicals expenses include amounts allocated from the "corporate and other" segment. The allocation is based on a combination of fee for service, proportional segment expenses and a three-year average of capital expenditures. Transfers of assets between segments are recorded at book amounts. Intersegment sales are made essentially at prevailing market prices. Assets and liabilities that are not identifiable by segment are allocated.

millions of dollars	Natural resources (a) 2006	2005	2004	Petroleum products 2006	2005	2004	Chemicals 2006	2005	2004
Revenues and other income									
External sales (b)	**4 619**	4 702	3 689	**18 527**	21 793	17 503	**1 359**	1 302	1 216
Intersegment sales	**3 837**	3 487	2 891	**2 256**	2 224	1 666	**345**	363	293
Investment and other income	**111**	331	45	**105**	60	42	**–**	–	–
	8 567	8 520	6 625	**20 888**	24 077	19 211	**1 704**	1 665	1 509
Expenses									
Exploration	**32**	43	59	**–**	–	–	**–**	–	–
Purchases of crude oil and products	**2 841**	2 837	2 110	**16 178**	19 212	14 769	**1 209**	1 191	1 064
Production and manufacturing	**1 994**	1 931	1 581	**1 266**	1 203	1 064	**189**	195	176
Selling and general (c)	**13**	36	9	**1 018**	1 096	1 043	**76**	81	88
Federal excise tax	**–**	–	–	**1 274**	1 278	1 264	**–**	–	–
Depreciation and depletion	**584**	651	633	**233**	230	257	**11**	12	13
Financing costs (note 14)	**2**	–	1	**6**	2	2	**–**	–	–
Total expenses	**5 466**	5 498	4 393	**19 975**	23 021	18 399	**1 485**	1 479	1 341
Income before income taxes	**3 101**	3 022	2 232	**913**	1 056	812	**219**	186	168
Income taxes (note 5)									
Current	**602**	955	771	**174**	409	314	**60**	69	61
Deferred	**123**	59	(56)	**115**	(47)	(58)	**16**	(4)	(2)
Total income tax expense	**725**	1 014	715	**289**	362	256	**76**	65	59
Net income	**2 376**	2 008	1 517	**624**	694	556	**143**	121	109
Cash flow from (used in) operating activities	**3 024**	2 440	2 331	**507**	799	908	**161**	94	126
Capital and exploration expenditures	**787**	937	1 113	**361**	478	283	**13**	19	15
Property, plant and equipment									
Cost	**14 926**	14 229	13 538	**6 581**	6 350	6 078	**702**	701	682
Accumulated depreciation and depletion	**(8 255)**	(7 780)	(7 337)	**(3 178)**	(3 037)	(2 959)	**(484)**	(474)	(459)
Net property, plant and equipment (d) (e)	**6 671**	6 449	6 201	**3 403**	3 313	3 119	**218**	227	223
Total assets	**7 513**	7 289	6 822	**6 450**	6 257	5 509	**504**	500	490

millions of dollars	Corporate and other 2006	2005	2004	Eliminations 2006	2005	2004	Consolidated 2006	2005	2004
Revenues and other income									
External sales (b)	**–**	–	–				**24 505**	27 797	22 408
Intersegment sales	**–**	–	–	**(6 438)**	(6 074)	(4 850)	**–**	–	–
Investment and other income	**67**	26	(35)				**283**	417	52
	67	26	(35)	**(6 438)**	(6 074)	(4 850)	**24 788**	28 214	22 460
Expenses									
Exploration	**–**	–	–				**32**	43	59
Purchases of crude oil and products	**–**	–	–	**(6 435)**	(6 072)	(4 849)	**13 793**	17 168	13 094
Production and manufacturing	**–**	–	–	**(3)**	(2)	(1)	**3 446**	3 327	2 820
Selling and general (c)	**177**	364	141				**1 284**	1 577	1 281
Federal excise tax	**–**	–	–				**1 274**	1 278	1 264
Depreciation and depletion	**3**	2	5				**831**	895	908
Financing costs (note 14)	**20**	6	4				**28**	8	7
Total expenses	**200**	372	150	**(6 438)**	(6 074)	(4 850)	**20 688**	24 296	19 433
Income before income taxes	**(133)**	(346)	(185)				**4 100**	3 918	3 027
Income taxes (note 5)									
Current	**(60)**	(72)	(43)				**776**	1 361	1 103
Deferred	**26**	(51)	(12)				**280**	(43)	(128)
Total income tax expense	**(34)**	(123)	(55)				**1 056**	1 318	975
Net income	**(99)**	(223)	(130)	**–**	–	–	**3 044**	2 600	2 052
Cash flow from (used in) operating activities	**(105)**	118	(53)				**3 587**	3 451	3 312
Capital and exploration expenditures	**48**	41	34				**1 209**	1 475	1 445
Property, plant and equipment									
Cost	**269**	246	205				**22 478**	21 526	20 503
Accumulated depreciation and depletion	**(104)**	(103)	(101)				**(12 021)**	(11 394)	(10 856)
Net property, plant and equipment (d) (e)	**165**	143	104				**10 457**	10 132	9 647
Total assets	**2 145**	1 959	1 504	**(471)**	(423)	(298)	**16 141**	15 582	14 027

(a) A significant portion of activities in the natural resources segment is conducted jointly with other companies. The segment includes the company's share of undivided interest in such activities as follows:

millions of dollars	**2006**	2005	2004
Total external and intersegment sales	**3 303**	3 687	2 744
Total expenses	**1 966**	1 805	1 598
Net income, after income tax	**1 148**	1 249	780
Total current assets	**516**	245	367
Long-term assets	**4 833**	4 742	4 140
Total current liabilities	**810**	967	948
Other long-term obligations	**344**	382	243
Cash flow from operating activities	**1 229**	1 223	1 211
Cash (used in) investing activities	**(403)**	(403)	(858)

(b) Includes export sales to the United States, as follows:

millions of dollars	**2006**	2005	2004
Natural resources	**1 936**	1 633	1 360
Petroleum products	**869**	856	1 074
Chemicals	**793**	750	678
Total export sales	**3 598**	3 239	3 112

(c) Consolidated selling and general expenses include delivery costs from final storage areas to customers of $316 million in 2006 (2005 – $310 million, 2004 – $307 million).

(d) Includes property, plant and equipment under construction of $782 million (2005 – $954 million).

(e) All goodwill has been assigned to the petroleum products segment. There have been no goodwill acquisitions, impairment losses or write-offs due to sales in the past three years.

4. Long-term debt

Issued	Maturity date	Interest rate	**2006** Millions of dollars	2005 Millions of dollars
2003	$250 million due May 26, 2007 and $250 million due August 26, 2007 (a)	Variable	**–**	500
2003	January 19, 2008 (a)	Variable	**318**	318
Long-term debt (b)			**318**	818
Capital leases (c)			**41**	45
Total long-term debt (d) (e)			**359**	863

(a) These are long-term variable-rate loans from an affiliated company of Exxon Mobil Corporation at interest equivalent to Canadian market rates.

(b) The average effective rate for the loans was 4.2 percent for 2006 (2005 – 2.8 percent).

(c) These obligations primarily relate to the capital lease for marine services, which are provided by the lessor commencing in 2004 for a period of 10 years, extendable for an additional five years. The average imputed rate was 10.7 percent in 2006 (2005 – 10.5 percent).

(d) Principal payments on long-term loans of $500 million are due in 2007 and $318 million are due in 2008. Principal payments on capital leases of approximately $3.6 million a year are due in each of the next five years.

(e) These amounts exclude that portion of long-term debt, totalling $907 million (2005 – $477 million), which matures within one year and is included in current liabilities.

5. Income taxes

millions of dollars	**2006**	2005	2004
Current income tax expense	**776**	1 361	1 103
Deferred income tax expense (a)	**280**	(43)	(128)
Total income tax expense (b)	**1 056**	1 318	975
Statutory corporate tax rate (percent)	**32.8**	35.6	37.0
Increase/(decrease) resulting from:			
Non-deductible royalty payments to governments	**–**	3.8	3.9
Resource allowance in lieu of royalty deduction	**–**	(5.2)	(7.0)
Manufacturing and processing credit	**–**	–	–
Enacted tax rate change	**(2.7)**	–	(1.8)
Other	**(4.3)**	(0.6)	0.1
Effective income tax rate	**25.8**	33.6	32.2

(a) The deferred income tax expense for the year is the difference in net deferred income tax liabilities at the beginning and end of the year. The provisions for deferred income taxes in 2006 include net (charges)/credits for the effect of changes in tax laws and rates of $81 million (2005 – nil; 2004 – $25 million).

(b) Cash outflow from income taxes, plus investment credits earned, was $1,000 million in 2006 (2005 – $1,024 million; 2004 – $641 million).

Deferred income taxes are based on differences between the accounting and tax values of assets and liabilities. These differences in value are remeasured at each year-end using the tax rates and tax laws expected to apply when those differences are realized or settled in the future. Components of deferred income tax liabilities and assets as at December 31 were:

millions of dollars	**2006**	2005
Depreciation and amortization	**1 588**	1 470
Successful drilling and land acquisitions	**263**	319
Pension and benefits (a)	**(311)**	(354)
Site restoration	**(161)**	(171)
Net tax loss carryforwards (b)	**(42)**	(49)
Capitalized interest	**50**	26
Other	**(42)**	(28)
Deferred income tax liabilities	**1 345**	1 213
LIFO inventory valuation	**(448)**	(487)
Other	**(125)**	(167)
Deferred income tax assets	**(573)**	(654)
Valuation allowance	**–**	–
Net deferred income tax liabilities	**772**	559

(a) Income taxes charged directly to shareholders' equity related to post-retirement benefit liability adjustment were $66 million benefit in 2006 and those related to minimum pension liability adjustment were $105 million benefit and $41 million benefit in 2005 and 2004, respectively.

(b) Tax losses can be carried forward indefinitely.

The operations of the company are complex, and related tax interpretations, regulations and legislation are continually changing. As a result, there are usually some tax matters in question. The company believes the provision made for income taxes is adequate.

6. Employee retirement benefits

Retirement benefits, which cover almost all retired employees and their surviving spouses, include pension-income and certain health-care and life-insurance benefits. They are met through funded registered retirement plans and through unfunded supplementary benefits that are paid directly to recipients. Funding of registered retirement plans complies with federal and provincial pension regulations, and the company makes contributions to the plans based on an independent actuarial valuation.

Pension-income benefits consist mainly of company-paid defined benefit plans that are based on years of service and final average earnings. The company shares in the cost of health-care and life-insurance benefits. The company's benefit obligations are based on the projected benefit method of valuation that includes employee service to date and present compensation levels, as well as a projection of salaries and service to retirement.

The expense and obligations for both funded and unfunded benefits are determined in accordance with United States generally accepted accounting principles and actuarial procedures. The process for determining retirement-income expense and related obligations includes making certain long-term assumptions regarding the discount rate, rate of return on plan assets and rate of compensation increases. The obligation and pension expense can vary significantly with changes in the assumptions used to estimate the obligation and the expected return on plan assets.

The benefit obligations and plan assets associated with the company's defined benefit plans are measured on December 31.

	Pension benefits		Other post-retirement benefits	
	2006	2005	**2006**	2005
Assumptions used to determine benefit obligations at December 31 (percent)				
Discount rate	**5.25**	5.00	**5.25**	5.00
Long-term rate of compensation increase	**3.50**	3.50	**3.50**	3.50

millions of dollars				
Change in projected benefit obligation				
Projected benefit obligation at January 1	**4 784**	4 260	**458**	436
Current service cost	**100**	86	**8**	7
Interest cost	**238**	239	**23**	24
Amendments	**–**	20	**(2)**	–
Actuarial loss/(gain)	**(122)**	549	**(19)**	26
Other	**–**	(88)	**–**	(13)
Benefits paid (a)	**(284)**	(282)	**(27)**	(22)
Projected benefit obligation at December 31	**4 716**	4 784	**441**	458
Accumulated benefit obligation at December 31	**4 207**	4 261		
Change in plan assets				
Fair value at January 1	**3 419**	2 984		
Actual return on plan assets	**514**	370		
Company contributions	**395**	350		
Other	**–**	(59)		
Benefits paid (b)	**(239)**	(226)		
Fair value at December 31	**4 089**	3 419		
Plan assets in excess of/(less than) projected benefit obligation at December 31				
Funded plans	**(294)**	(984)	**–**	–
Unfunded plans	**(333)**	(381)	**(441)**	(458)
Total (c)	**(627)**	(1 365)	**(441)**	(458)

(a) Benefit payments for funded and unfunded plans.
(b) Benefit payments for funded plan only.
(c) Fair value of assets less projected benefit obligation shown above.

Effective December 31, 2006, the company adopted SFAS 158, which requires an employer to recognize the overfunded or underfunded status of a defined benefit post-retirement plan as an asset or liability in its balance sheet and to recognize changes in that funded status in the year in which the changes occur through other nonowner changes in equity. In 2006, the amounts recorded in other nonowner changes in equity for net actuarial losses and prior service cost are required by SFAS 158. For 2005, SFAS 87 required an employer to recognize a liability in its balance sheet that was at least equal to the unfunded accumulated benefit obligation for defined benefit pension plans.

	Pension benefits			Other post-retirement benefits		
millions of dollars	**2006**	2005	2004	**2006**	2005	2004
Amounts recorded in the consolidated balance sheet consist of:						
Other intangible assets, net	**–**	93		**–**	–	
Current liabilities	**(28)**	(24)		**(23)**	(23)	
Other long-term obligations	**(599)**	(818)		**(418)**	(334)	
Total	**(627)**	(749)		**(441)**	(357)	
Cumulative amounts recorded in other nonowner changes in equity consist of:						
Net actuarial loss/(gain)	**947**	875		**73**	–	
Prior service cost	**74**	–		**–**	–	
Total	**1 021**	875		**73**	–	
Assumptions used to determine net periodic benefit cost for years ended December 31 (percent)						
Discount rate	**5.00**	5.75	6.25	**5.00**	5.75	6.25
Long-term rate of compensation increase	**3.50**	3.50	3.50	**3.50**	3.50	3.50
Long-term rate of return on funded assets	**8.25**	8.25	8.25	**–**	–	–

millions of dollars						
Components of net periodic benefit cost						
Current service cost	**100**	86	76	**8**	7	6
Interest cost	**238**	239	237	**23**	24	24
Expected return on plan assets	**(299)**	(257)	(223)	**–**	–	–
Amortization of prior service cost	**20**	25	27	**–**	–	–
Recognized actuarial loss/(gain)	**114**	83	68	**8**	7	4
Net periodic benefit cost	**173**	176	185	**39**	38	34
Changes in amounts recorded in other nonowner changes in equity						
Net actuarial loss/(gain)	**72**	317	143	**73**	–	–
Prior service cost	**74**	–	–	**–**	–	–
Total recorded in other nonowner changes in equity	**146**	317	143	**73**	–	–
Total recorded in net periodic benefit cost and other nonowner changes in equity, before tax	**319**	493	328	**112**	38	34

Costs for defined contribution plans, primarily the employee savings plan, were $30 million in 2006 (2005 – $30 million; 2004 – $32 million).

A summary of the change in other nonowner changes in equity is shown in the table below:

millions of dollars	**2006**	Total pension and other post-retirement benefits 2005	2004
(Charge)/credit to accumulated other nonowner changes in equity, before tax	**(219)**	(317)	(143)
Deferred income tax (charge)/credit (note 5)	**66**	105	41
(Charge)/credit to accumulated other nonowner changes in equity, after tax	**(153)**	(212)	(102)

The impact of adopting SFAS 158 is shown in the table below:

millions of dollars	Pre-SFAS 158 with minimum pension liability adjustment	SFAS 158 adoption adjustments	Post-SFAS 158
Other intangible assets, net	73	(6)	67
Total assets	16 147	(6)	16 141
Other long-term obligations	990	693	1 683
Deferred income tax liabilities	1 557	(212)	1 345
Accumulated other nonowner changes in equity	(246)	(487)	(733)
Total liabilities and shareholders' equity	16 147	(6)	16 141

Preceding data on this note conform with current accounting standards that specify use of a discount rate at which post-retirement liabilities could be effectively settled. The discount rate for calculating year-end post-retirement liabilities is based on the yield for high quality, long-term Canadian corporate bonds at year-end with an average maturity (or duration) approximately that of the liabilities. The measurement of the accumulated post-retirement benefit obligation assumes a health-care cost trend rate of 8.50 percent in 2007 that declines to 4.50 percent by 2012.

The company establishes the long-term expected rate of return on plan assets by developing a forward-looking long-term return assumption for each asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single long-term rate of return is then calculated as the weighted average of the target asset allocation and the long-term return assumption for each asset class. The 2006 long-term expected return of 8.25 percent used in the calculations of pension expense compares to an actual rate of return over the past decade of 9.82 percent.

The company's pension plan asset allocation at December 31, 2005 and 2006, and target allocation for 2007 are as follows:

Asset category (percent)	Target allocation 2007	Percentage of plan assets at December 31 **2006**	2005
Equity securities	50 – 75	**64**	62
Debt securities	25 – 50	**36**	38
Other	0 – 10	**–**	–

The company's investment strategy for benefit plan assets reflects a long-term view, a careful assessment of the risks inherent in various asset classes and broad diversification to reduce the risk of the total portfolio. The company primarily invests in funds that follow an index-based strategy to achieve its objectives of diversifying risk while minimizing costs. The fund holds Imperial Oil Limited common shares primarily only to the extent necessary to replicate the relevant equity index. Asset-liability studies, or simulations of the interaction of cash flows associated with both assets and liabilities, are periodically used to establish the preferred target asset allocation. The target asset allocation for equity securities reflects the long-term nature of the liability. The balance of the fund is targeted to debt securities.

A summary of pension plans with accumulated benefit obligations in excess of plan assets is shown in the table below:

	Pension benefits	
millions of dollars	**2006**	2005
For funded pension plans with accumulated benefit obligations in excess of plan assets:		
Projected benefit obligation	**375**	4 403
Accumulated benefit obligation	**308**	3 908
Fair value of plan assets	**239**	3 419
Accumulated benefit obligation less fair value of plan assets	**69**	489
For unfunded plans covered by book reserves:		
Projected benefit obligation	**333**	381
Accumulated benefit obligation	**314**	353

Estimated 2007 amortization from accumulated other nonowner changes in equity

millions of dollars	Pension benefits	Other post-retirement benefits
Net actuarial loss/(gain) (a)	76	6
Prior service cost (b)	19	–

(a) The company amortizes the net balance of actuarial loss/(gain) over the average remaining service period of active plan participants.
(b) The company amortizes prior service cost on a straight-line basis as permitted under SFAS 87.

Cash flows
Benefit payments expected in:

millions of dollars	Pension benefits	Other post-retirement benefits
2007	245	23
2008	248	24
2009	252	24
2010	257	24
2011	264	24
2012 – 2016	1 465	123

In 2007, the company expects to make cash contributions of about $183 million to its pension plan.

Sensitivities

A one percent change in the assumptions at which retirement liabilities could be effectively settled is as follows:

Increase/(decrease) millions of dollars	One percent increase	One percent decrease
Rate of return on plan assets:		
Effect on net benefit cost	(40)	40
Discount rate:		
Effect on net benefit cost	(60)	70
Effect on benefit obligation	(590)	730
Rate of pay increases:		
Effect on net benefit cost	40	(35)
Effect on benefit obligation	185	(150)

A one percent change in the assumed health-care cost trend rate would have the following effects:

Increase/(decrease) millions of dollars	One percent increase	One percent decrease
Effect on service and interest cost components	4	(3)
Effect on benefit obligation	45	(35)

7. Other long-term obligations

millions of dollars	**2006**	2005
Employee retirement benefits (note 6) (a)	**1 017**	1 152
Asset retirement obligations and other environmental liabilities (b)	**438**	423
Other obligations	**228**	153
Total other long-term obligations	**1 683**	1 728

(a) Total recorded employee retirement benefit obligations also include $51 million in current liabilities (2005 – $47 million).

(b) Total asset retirement obligations and other environmental liabilities also include $97 million in current liabilities (2005 – $76 million).

The change in asset retirement obligations liability is as follows:

millions of dollars	**2006**	2005
Asset retirement obligations liability at January 1	**367**	328
Additions	**61**	53
Accretion	**22**	20
Settlement	**(28)**	(34)
Asset retirement obligations liability at December 31	**422**	367

8. Derivatives and financial instruments

No energy derivatives, foreign-exchange forward contracts or currency and interest-rate swaps were transacted in the past three years. The company maintains a system of controls that includes a policy covering the authorization, reporting and monitoring of derivative activity.

The fair value of the company's financial instruments is determined by reference to various market data and other appropriate valuation techniques. There are no material differences between the fair values of the company's financial instruments from the recorded book value.

9. Share-based incentive compensation programs

Share-based incentive compensation programs are designed to retain selected employees, reward them for high performance and promote individual contribution to sustained improvement in the company's future business performance and shareholder value.

Incentive share units, deferred share units and restricted stock units

Incentive share units have value if the market price of the company's common shares when the unit is exercised exceeds the market value when the unit was issued, as adjusted for any share splits. The issue price of incentive share units is the closing price of the company's shares on the Toronto Stock Exchange on the grant date. Up to 50 percent of the units may be exercised after one year from issuance; an additional 25 percent may be exercised after two years; and the remaining 25 percent may be exercised after three years. Incentive share units are eligible for exercise up to 10 years from issuance. The units may expire earlier if employment is terminated other than by retirement, death or disability.

The deferred share unit plan is made available to selected executives and nonemployee directors. The selected executives can elect to receive all or part of their performance bonus compensation in units and the nonemployee directors can elect to receive all or part of their directors' fees in units. The number of units granted to executives is determined by dividing the amount of the bonus elected to be received as deferred share units by the average of the closing prices of the company's shares on the Toronto Stock Exchange for the five consecutive trading days immediately prior to the date that the bonus would have been paid. The number of units granted to a nonemployee director is determined at the end of each calendar quarter by dividing the amount of director's fees for the calendar quarter that the nonemployee director elected to receive as deferred share units by the average closing price of the company's shares for the five consecutive trading days immediately prior to the last day of the calendar quarter. Additional units are granted based on the cash dividend payable on the company's shares divided by the average closing price immediately prior to the payment date for that dividend and multiplying the resulting number by the number of deferred share units held by the recipient, as adjusted for any share splits.

Deferred share units cannot be exercised until after termination of employment with the company or resignation as a director and must be exercised no later than December 31 of the year following termination or resignation. On the exercise date, the cash value to be received for the units is determined based on the average closing price of the company's shares for the five consecutive trading days immediately prior to the date of exercise, as adjusted for any share splits.

Under the restricted stock unit plan, each unit entitles the recipient to the conditional right to receive from the company, upon exercise, an amount equal to the five-day average of the closing price of the company's common shares on the Toronto Stock Exchange on and immediately prior to the exercise dates. Fifty percent of the units are exercised three years following the grant date, and the remainder are exercised seven years following the grant date. For units granted in 2002 to 2005, the exercise date has been changed from December 31 to December 4 for units exercised in 2006 and subsequent years. For units granted in 2002, 2003, 2004 and 2005 to be exercised subsequent to the company's May 2006 three-for-one share split, the company has indicated that it will increase the cash payment or number of shares issued per unit, as the case may be, by the factor of three.

All units require settlement by cash payments with one exception. The restricted stock unit program was amended for units granted in 2002 and future years by providing that the recipient may receive one common share of the company per unit or elect to receive the cash payment for the units to be exercised in the seventh year following the grant date.

In accordance with SFAS 123R, the company accounts for these units by using the fair-value-based method. The fair value of awards in the form of incentive share, deferred share and restricted stock units is the market price of the company's stock, which is the same method of accounting as under SFAS 123. Under this method, compensation expense related to the units of these programs is measured each reporting period based on the company's current stock price and is recorded in the consolidated statement of income over the vesting period.

The following table summarizes information about these units for the year ended December 31, 2006:

	Incentive share units (a)	Deferred share units (a)	Restricted stock units (a)
Outstanding at January 1, 2006	10 884 891	138 567	10 556 730
Granted	–	**6 662**	**1 935 658**
Exercised	**(1 797 141)**	**(60 781)**	**(2 488 047)**
Cancelled or adjusted	**(16 500)**	–	**(7 951)**
Outstanding at December 31, 2006	**9 071 250**	**84 448**	**9 996 390**

(a) Reflects number of units granted after the share split in 2006, plus the number of units granted prior to the share split in 2006 as adjusted for the share splits that occurred in 1998 and 2006.

The compensation expense charged against income for these programs was $133 million, $238 million and $95 million in 2006, 2005, and 2004, respectively. Total income tax benefit recognized in income related to this compensation expense was $45 million, $127 million and $46 million in 2006, 2005 and 2004, respectively. Cash payments of $162 million, $169 million and $64 million for these programs were made in 2006, 2005 and 2004, respectively.

As of December 31, 2006, there was $265 million of total before-tax unrecognized compensation expenses related to nonvested restricted stock units based on the company's share price at the end of the current reporting period. The weighted average vesting period of nonvested restricted stock units is 3.9 years. All units under the incentive share and deferred share programs have vested as of December 31, 2006.

Incentive stock options

In April 2002, incentive stock options were granted for the purchase of the company's common shares at an exercise price of $15.50 per share (adjusted to reflect the three-for-one share split). Up to 50 percent of the options may be exercised on or after January 1, 2003; a further 25 percent may be exercised on or after January 1, 2004; and the remaining 25 percent may be exercised on or after January 1, 2005. Any unexercised options expire after April 29, 2012. The company has not issued incentive stock options since 2002 and has no plans to issue incentive stock options in the future.

As permitted by SFAS 123, the company continues to apply the intrinsic-value-based method of accounting for the incentive stock options granted in April 2002. Under this method, compensation expense is not recognized on the issuance of stock options, as the exercise price is equal to the market value at the date of grant. All incentive stock options have vested as of January 1, 2005.

No compensation expense and no income tax benefit related to stock options were recognized for stock options in 2006, 2005 and 2004. Cash received from stock options exercised in 2006 was $10 million. The aggregate intrinsic value of stock options exercised was $18 million, $43 million and $5 million in 2006, 2005 and 2004, respectively, and for the balance of outstanding stock options is $152 million.

The average fair value of each option granted during 2002 was $4.23 (adjusted to reflect the three-for-one share split). The fair value was estimated at the grant date using an option-pricing model with the following weighted average assumptions: risk-free interest rate of 5.7 percent, expected life of five years, volatility of 25 percent and a dividend yield of 1.9 percent.

The company has purchased shares on the market to fully offset the dilutive effects from the exercise of stock options. The practice is expected to continue.

The following table summarizes information about stock options for the year ended December 31, 2006:

	Units (a)	Exercise price (dollars) (b)	Remaining contractual term (years)
Incentive stock options			
Outstanding at January 1, 2006	6 135 000	15.50	
Granted	–		
Exercised	**(628 335)**	**15.50**	
Cancelled or adjusted	**21 000**		
Outstanding at December 31, 2006	**5 527 665**	**15.50**	**5.3**

(a) Reflects number of units granted, as adjusted for any share splits.
(b) Adjusted to reflect the three-for-one share split.

10. Investment and other income

Investment and other income includes gains and losses on asset sales as follows:

millions of dollars	**2006**	2005	2004
Proceeds from asset sales	**212**	440	102
Book value of assets sold	**78**	96	59
Gain/(loss) on asset sales, before tax (a)	**134**	344	43
Gain/(loss) on asset sales, after tax (a)	**96**	233	32

(a) 2005 included a gain of $251 million ($163 million, after tax) from the sale of the wholly owned Redwater and interests in the North Pembina fields.

11. Commitments and contingent liabilities

At December 31, 2006, the company had commitments for non-cancellable operating leases and other long-term agreements that require the following minimum future payments:

millions of dollars	2007	2008	2009	2010	2011	After 2011
Operating leases (a)	**53**	**51**	**46**	**40**	**35**	**48**
Unconditional purchase obligations (b)	**58**	**58**	**57**	**26**	**26**	**40**
Firm capital commitments (c)	**149**	**11**	**17**	**1**	**–**	**–**
Other long-term agreements (d)	**271**	**238**	**164**	**147**	**128**	**240**

(a) Total rental expense incurred for operating leases in 2006 was $79 million (2005 – $83 million; 2004 – $104 million) which included minimum rental expenditures of $66 million (2005 – $63 million; 2004 – $77 million). Related rental income was not material.

(b) Unconditional purchase obligations are those long-term commitments that are non-cancellable or cancellable only under certain conditions. These mainly pertain to pipeline throughput agreements. Total payments under unconditional purchase obligations were $100 million in 2006 (2005 – $104 million; 2004 – $117 million).

(c) Firm capital commitments related to capital projects, shown on an undiscounted basis, totalled approximately $178 million at the end of 2006 (2005 – $232 million). Commitments of $136 million were associated with the company's share of upstream capital projects; the largest commitment of $41 million related to Syncrude.

(d) Other long-term agreements include primarily raw material supply and transportation services agreements. Total payments under other long-term agreements were $441 million in 2006 (2005 – $448 million; 2004 – $355 million). Payments under other long-term agreements related to the company's share of undivided interest in activities conducted jointly with other companies are approximately $103 million per year.

Other commitments arising in the normal course of business for operating and capital needs do not materially affect the company's consolidated financial position.

The company was contingently liable at December 31, 2006, for a maximum of $87 million relating to guarantees for purchasing operating equipment and other assets from its rural marketing associates upon expiry of the associate agreement or the resignation of the associate. The company expects that the fair value of the operating equipment and other assets so purchased would cover the maximum potential amount of future payment under the guarantees.

Various lawsuits are pending against Imperial Oil Limited and its subsidiaries. The company accrues an undiscounted liability for those contingencies where the incurrence of a loss is determined to be probable and the amount can be reasonably estimated. Based on a consideration of all relevant facts and circumstances, the company does not believe the ultimate outcome of any currently pending lawsuits against the company will have a material adverse effect on the company's operations or financial condition. There are no events or uncertainties known to management beyond those already included in reported financial information that would indicate a material change in future operating results or financial condition.

12. Common shares

thousands of shares	**As at Dec. 31 2006**	As at Dec. 31 2005
Authorized (prior period data have not been restated)	**1 100 000**	450 000

Effective May 23, 2006, the issued common shares of the company were split on a three-for-one basis and the number of authorized shares was increased from 450 million to 1,100 million. The prior period number of shares outstanding and shares purchased, as well as net income and dividends per share, have been adjusted to reflect the three-for-one split.

From 1995 to 2005, the company purchased shares under eleven 12-month normal course share purchase programs, as well as an auction tender. On June 23, 2006, another 12-month normal course share purchase program was implemented with an allowable purchase of 48.8 million shares (five percent of the total at June 21, 2006), less any shares purchased by the employee savings plan and company pension fund. The results of these activities are shown below.

Year	Purchased shares (thousands)	Millions of dollars
1995 to 2004	697 582	6 840
2005	52 527	1 795
2006	**45 514**	**1 818**
Cumulative purchases to date	795 623	10 453

Exxon Mobil Corporation's participation in the above maintained its ownership interest in Imperial at 69.6 percent.

The excess of the purchase cost over the stated value of shares purchased has been recorded as a distribution of retained earnings.

The company's common share activities are summarized below:

	Thousands of shares	Millions of dollars
Balance as at January 1, 2004	1 087 959	1 859
Issued for cash under the stock option plan	822	13
Purchases	(40 821)	(71)
Balance as at December 31, 2004	1 047 960	1 801
Issued for cash under the stock option plan	2 442	38
Purchases	(52 527)	(92)
Balance as at December 31, 2005	997 875	1 747
Issued for cash under the stock option plan	**627**	**10**
Purchases	**(45 514)**	**(80)**
Balance as at December 31, 2006	**952 988**	**1 677**

The following table provides the calculation of basic and diluted earnings per share:

	2006	2005	2004
Net income per common share – basic			
Net income (millions of dollars)	**3 044**	2 600	2 052
Weighted average number of common shares outstanding (thousands of shares)	**975 128**	1 024 119	1 070 502
Net income per common share (dollars)	**3.12**	2.54	1.92
Net income per common share – diluted			
Net income (millions of dollars)	**3 044**	2 600	2 052
Weighted average number of common shares outstanding (thousands of shares)	**975 128**	1 024 119	1 070 502
Effect of employee stock-based awards (thousands of shares)	**4 460**	4 179	2 454
Weighted average number of common shares outstanding, assuming dilution (thousands of shares)	**979 588**	1 028 298	1 072 956
Net income per common share (dollars)	**3.11**	2.53	1.91

13. Miscellaneous financial information

In 2006, net income included an after-tax gain of $14 million (2005 – $5 million gain; 2004 – $23 million gain) attributable to the effect of changes in last-in, first-out (LIFO) inventories. The replacement cost of inventories was estimated to exceed their LIFO carrying values at December 31, 2006 by $1,509 million (2005 – $1,429 million). Inventories of crude oil and products at year-end consisted of the following:

millions of dollars	2006	2005
Crude oil	**211**	174
Petroleum products	**277**	234
Chemical products	**54**	63
Natural gas and other	**14**	10
Total inventories of crude oil and products	**556**	481

Research and development costs in 2006 were $73 million (2005 – $68 million; 2004 – $70 million) before investment tax credits earned on these expenditures of $7 million (2005 – $10 million; 2004 – $7 million). Research and development costs are included in expenses due to the uncertainty of future benefits.

Cash flow from operating activities included dividends of $18 million received from equity investments in 2006 (2005 – $21 million; 2004 – $18 million).

14. Financing costs

millions of dollars	2006	2005	2004
Debt-related interest	**63**	45	37
Capitalized interest	**(48)**	(41)	(34)
Net interest expense	**15**	4	3
Other interest	**13**	4	4
Total financing costs (a)	**28**	8	7

(a) Cash interest payments in 2006 were $71 million (2005 – $45 million; 2004 – $41 million). The weighted average interest rate on short-term borrowings in 2006 was 4.1 percent (2005 – 2.7 percent).

15. Transactions with related parties

Revenues and expenses of the company also include the results of transactions with Exxon Mobil Corporation and affiliated companies (ExxonMobil) in the normal course of operations. These were conducted on terms as favourable as they would have been with unrelated parties and primarily consisted of the purchase and sale of crude oil and petroleum and chemical products, as well as transportation, technical and engineering services. Transactions with ExxonMobil also included amounts paid and received in connection with the company's participation in a number of natural resources activities conducted jointly in Canada. The company has existing agreements with affiliates of Exxon Mobil Corporation to provide computer and customer support services to the company and to share common business and operational support services that allow the companies to consolidate duplicate work and systems. The company has a contractual agreement with an affiliate of Exxon Mobil Corporation in Canada to operate the Western Canada production properties owned by ExxonMobil. This contractual agreement is designed to provide organizational efficiencies and to reduce costs. No separate legal entities were created from this arrangement. Separate books of account continue to be maintained for Imperial and ExxonMobil. Imperial and ExxonMobil retain ownership of their respective assets and there is no impact on operations or reserves.

Certain charges from ExxonMobil have been capitalized; they are not material in the aggregate.

The company borrowed $818 million (Cdn) from an affiliated company of Exxon Mobil Corporation under two long-term loan agreements as presented in note 4.

As at December 31, 2006, the company had outstanding loans of $33 million (2005 – $32 million) to Montreal Pipe Line Limited, in which the company has an equity interest, for financing of the equity company's capital expenditure programs and working capital requirements.

16. Net payments/payables to governments

millions of dollars	**2006**	2005	2004
Current income tax expense (note 5)	**776**	1 361	1 103
Federal excise tax	**1 274**	1 278	1 264
Property taxes included in expenses	**100**	99	85
Payroll and other taxes included in expenses	**46**	52	50
GST/QST/HST collected (a)	**2 715**	2 703	2 297
GST/QST/HST input tax credits (a)	**(2 293)**	(2 344)	(1 948)
Other consumer taxes collected for governments	**1 667**	1 613	1 670
Crown royalties	**904**	620	472
Total paid or payable to governments	**5 189**	5 382	4 993
Less investment tax credits and other receipts	**11**	9	14
Net paid or payable to governments	**5 178**	5 373	4 979
Net paid or payable to:			
Federal government	**2 352**	2 736	2 472
Provincial governments	**2 726**	2 538	2 422
Local governments	**100**	99	85
Net paid or payable to governments	**5 178**	5 373	4 979

(a) The abbreviations refer to the federal goods and services tax, the Quebec sales tax and the federal/provincial harmonized sales tax, respectively. The HST is applicable in the provinces of Nova Scotia, New Brunswick and Newfoundland and Labrador.

Natural resources segment – supplemental information (unaudited)

Pages 58 to 61 provide information about the natural resources segment (see note 3, page 43). The information excludes items not related to oil and natural gas extraction, such as administrative and general expenses, pipeline operations, gas plant processing fees, and gains or losses on asset sales.

In addition to proved oil and gas reserves, the company has a 25 percent interest in proven synthetic crude oil reserves in the Syncrude project. For internal management purposes, the company views these reserves and their development as an integral part of its total natural resources operations. However, for financial reporting purposes, these reserves are required to be reported separately from the oil and gas reserves as shown on page 61.

The synthetic crude oil reserves are not considered in the standardized measure of discounted future cash flows for oil and gas reserves on page 59. The company's share of Syncrude results of operations, capital and exploration expenditures and property, plant and equipment is also excluded from the following tables on this page.

Results of operations

	Oil and gas		
millions of dollars	**2006**	2005	2004
Sales to customers (a)	**2 601**	2 739	2 160
Intersegment sales (a) (b)	**1 251**	1 013	976
	3 852	3 752	3 136
Production expenses	**1 016**	1 035	870
Exploration expenses	**32**	31	44
Depreciation and depletion	**467**	583	565
Income taxes	**564**	716	547
Results of operations	**1 773**	1 387	1 110
Capital and exploration expenditures			
Property costs (c)			
Proved	**–**	–	–
Unproved	**–**	7	1
Exploration costs	**32**	37	43
Development costs	**496**	330	408
Total capital and exploration expenditures	**528**	374	452
Property, plant and equipment			
Property costs (c)			
Proved	**3 226**	3 231	
Unproved	**139**	162	
Producing assets	**6 392**	6 111	
Support facilities	**184**	174	
Incomplete construction	**595**	432	
Total cost	**10 536**	10 110	
Accumulated depreciation and depletion	**7 326**	6 934	
Net property, plant and equipment	**3 210**	3 176	

(a) Sales to customers or intersegment sales do not include the sale of natural gas and natural gas liquids purchased for resale, as well as royalty payments. These items are reported gross in note 3 in "external sales", "intersegment sales" and in "purchases of crude oil and products".

(b) Sales of crude oil to consolidated affiliates are at market value, using posted field prices. Sales of natural gas liquids to consolidated affiliates are at prices estimated to be obtainable in a competitive, arm's-length transaction.

(c) "Property costs" are payments for rights to explore for petroleum and natural gas and for purchased reserves (acquired tangible and intangible assets such as gas plants, production facilities and producing-well costs are included under "producing assets"). "Proved" represents areas where successful drilling has delineated a field capable of production. "Unproved" represents all other areas.

Standardized measure of discounted future cash flows

As required by the Financial Accounting Standards Board, the standardized measure of discounted future net cash flows is computed by applying year-end prices, costs and legislated tax rates and a discount factor of 10 percent to net proved reserves. The standardized measure includes costs for future dismantlement, abandonment and remediation obligations. The company believes the standardized measure does not provide a reliable estimate of the company's expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions, including year-end prices, which represent a single point in time and therefore may cause significant variability in cash flows from year to year as prices change. The table below excludes the company's interest in Syncrude.

Standardized measure of discounted future net cash flows related to proved oil and gas reserves

	Oil and gas		
millions of dollars	**2006**	2005	2004
Future cash flows	**36 751**	21 911	11 625
Future production costs	**(16 290)**	(11 376)	(3 123)
Future development costs	**(2 633)**	(2 039)	(1 492)
Future income taxes	**(5 039)**	(2 777)	(2 260)
Future net cash flows	**12 789**	5 719	4 750
Annual discount of 10 percent for estimating timing of cash flows	**(6 374)**	(1 405)	(1 433)
Discounted future cash flows	**6 415**	4 314	3 317

Changes in standardized measure of discounted future net cash flows related to proved oil and gas reserves

Balance at beginning of year	**4 314**	3 317	4 738
Changes resulting from:			
Sales and transfers of oil and gas produced, net of production costs	**(2 839)**	(2 650)	(2 240)
Net changes in prices, development costs and production costs	**4 221**	3 343	(3 692)
Extensions, discoveries, additions and improved recovery, less related costs	**(4)**	(513)	(43)
Development costs incurred during the year	**411**	272	345
Revisions of previous quantity estimates	**87**	660	1 838
Accretion of discount	**568**	417	663
Net change in income taxes	**(343)**	(532)	1 708
Net change	**2 101**	997	(1 421)
Balance at end of year	**6 415**	4 314	3 317

Net proved developed and undeveloped reserves (a)

	Crude oil and NGLs millions of barrels			Natural gas billions of cubic feet	Synthetic crude oil millions of barrels
	Conventional	Heavy Oil (b)	Total		
Beginning of year 2004	126	763	889	1 023	781
Revisions and improved recovery	11	(490)	(479)	(32)	(3)
(Sale)/purchase of reserves in place	–	–	–	(13)	–
Discoveries and extensions	–	–	–	3	–
Production	(22)	(41)	(63)	(190)	(21)
End of year 2004	115	232	347	791	757
Revisions and improved recovery	–	350	350	137	–
(Sale)/purchase of reserves in place	(12)	–	(12)	(6)	–
Discoveries and extensions	–	14	14	13	–
Production	(20)	(45)	(65)	(188)	(19)
End of year 2005	83	551	634	747	738
Revisions and improved recovery	**4**	**236**	**240**	**140**	**1**
(Sale)/purchase of reserves in place	**(1)**	**–**	**(1)**	**(6)**	**–**
Discoveries and extensions	**–**	**–**	**–**	**10**	**–**
Production	**(15)**	**(46)**	**(61)**	**(181)**	**(21)**
End of year 2006	**71**	**741**	**812**	**710**	**718**

(a) Net reserves are the company's share of reserves after deducting the shares of mineral owners or governments or both. All reported reserves are located in Canada. Reserves of natural gas are calculated at a pressure of 14.73 pounds per square inch at 60°F.

(b) Heavy oil reserves typically are represented by crude oils with a viscosity of greater than 10,000 cP and recovered through enhanced thermal operations. Currently, the company's heavy oil reserves are from the Cold Lake production operations.

The information above describes changes during the years and balances of proved oil and gas and synthetic crude oil reserves at year-end 2004, 2005 and 2006. The definitions used for oil and gas reserves are in accordance with the U.S. Securities and Exchange Commission's (SEC) Rule 4-10 (a) of Regulation S-X, paragraphs (2), (3) and (4).

Crude oil and natural gas reserve estimates, excluding Syncrude, are based on geological and engineering data, which have demonstrated with reasonable certainty that these reserves are recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Estimates of synthetic crude oil reserves are based on detailed geological and engineering assessments of in-place crude bitumen volumes, the mining plan, historical extraction recovery and upgrading yield factors, installed plant operating capacity and operating approval limits.

Beginning in 2004, the year-end reserves volumes as well as the reserves change categories shown in the proved reserves tables are calculated using December 31 prices and costs. These reserves quantities are also used in calculating unit-of-production depreciation rates and in calculating the standardized measure of discounted net cash flow. The United States Securities and Exchange Commission regulations preclude the company from showing in the Financial section of this document the reserves that are calculated in a manner which is consistent with the basis that the company uses to make its investment decisions. The use of year-end prices for reserves estimation introduces short-term price volatility into the process since annual adjustments are required based on prices occurring on a single day. The company believes that this approach is inconsistent with the long-term nature of the natural resources business where production from individual projects often spans multiple decades. The use of prices from a single date is not relevant to the investment decisions made by the company and annual variations in reserves based on such year-end prices are not of consequence to how the business is actually managed.

Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the evaluation or revaluation of already available geologic, reservoir or production data; new geologic, reservoir or production data; or changes in year-end prices and costs that are used in the determination of reserves. This category can also include changes associated with the performance of improved recovery projects and significant changes in either development strategy or production equipment/facility capacity.

Net proved reserves are determined by deducting the estimated future share of mineral owners or governments or both. For conventional crude oil (excluding enhanced oil-recovery projects) and natural gas, net proved reserves are based on estimated future royalty rates representative of those existing as of the date the estimate is made. Actual future royalty rates may vary with production and price. For enhanced oil-recovery projects, Syncrude and Cold Lake, net proved reserves are based on the company's best estimate of average royalty rates over the life of each project. Actual future royalty rates may vary with production, price and costs.

Reserves data do not include crude oil and natural gas, such as those discovered in the Beaufort Sea-Mackenzie Delta and the Arctic islands, or the heavy oil and oil sands, other than reserves attributable to commercial phases of Cold Lake production operations and Syncrude.

Oil-equivalent barrels (OEB) may be misleading, particularly if used in isolation. An OEB conversion ratio of 6,000 cubic feet to one barrel on an energy-equivalent conversion method is primarily applicable at the burner tip and does not represent a value equivalency at the well head. No independent qualified reserves evaluator or auditor was involved in the preparation of the reserves data.

Share ownership, trading and performance

	2006	2005	2004	2003	2002
Share ownership					
Average number outstanding, weighted monthly (thousands)	**975 128**	1 024 119	1 070 502	1 116 033	1 136 625
Number of shares outstanding at December 31 (thousands)	**952 988**	997 875	1 047 960	1 087 959	1 136 589
Shares held in Canada at December 31 (percent)	**13.0**	13.8	14.6	15.2	15.8
Number of registered shareholders at December 31 (a)	**13 561**	14 096	14 953	15 516	15 988
Number of shareholders registered in Canada	**11 844**	12 331	13 088	13 601	14 014
Shares traded (thousands)	**321 245**	357 633	281 334	282 189	249 057
Share prices (dollars) (b)					
Toronto Stock Exchange					
High	**45.20**	45.79	24.55	19.41	16.46
Low	**34.31**	22.50	18.81	14.40	12.84
Close at December 31	**42.93**	38.47	23.72	19.18	14.95
American Stock Exchange ($U.S.)					
High	**40.38**	39.14	20.82	14.92	10.62
Low	**29.99**	18.27	14.11	9.42	8.00
Close at December 31	**36.83**	33.20	19.79	14.81	9.57
Net income per share (dollars) (b)					
Basic	**3.12**	2.54	1.92	1.53	1.07
Diluted	**3.11**	2.53	1.91	1.53	1.07
Price ratios at December 31					
Share price to net earnings (c)	**13.8**	15.2	12.4	12.6	14.0
Dividends declared (b) (d)					
Total (millions of dollars)	**311**	320	314	323	318
Per share (dollars)	**0.32**	0.31	0.29	0.29	0.28

(a) Exxon Mobil Corporation owns 69.6 percent of Imperial's shares.
(b) Adjusted to reflect the three-for-one share split.
(c) Closing share price at December 31 at the Toronto Stock Exchange, divided by net income per share – diluted.
(d) The fourth-quarter dividend is paid on January 1 of the succeeding year.

Information for security holders outside Canada

Cash dividends paid to shareholders resident in countries with which Canada has an income tax convention are usually subject to a Canadian nonresident withholding tax of 15 percent.

The withholding tax is reduced to five percent on dividends paid to a corporation resident in the United States that owns at least 10 percent of the voting shares of the company.

Imperial Oil Limited is a qualified foreign corporation for purposes of the reduced U.S. capital gains tax rates (15 percent and five percent for certain individuals), which are applicable to dividends paid by U.S. domestic corporations and qualified foreign corporations.

There is no Canadian tax on gains from selling shares or debt instruments owned by nonresidents not carrying on business in Canada.

Valuation day price

For capital gains purposes, Imperial's common shares were quoted at $3.50 a share on December 31, 1971, and $5.10 on February 22, 1994. Both amounts are restated for the 1998 and 2006 three-for-one share splits.

Employees

	2006	2005	2004	2003	2002
Number of employees at December 31	**4 869**	5 096	6 083	6 256	6 460

	2006 three months ended				2005 three months ended			
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	Mar. 31	June 30	Sept. 30	Dec. 31
Financial data (millions of dollars)								
Total revenues and other income (b)	**5 818**	**6 688**	**6 651**	**5 631**	5 958	6 802	7 711	7 743
Total expenses (b)	**4 928**	**5 604**	**5 421**	**4 735**	5 370	5 989	6 753	6 184
Income before income taxes	**890**	**1 084**	**1 230**	**896**	588	813	958	1 559
Income taxes	**(299)**	**(247)**	**(408)**	**(102)**	(195)	(274)	(306)	(543)
Net income	**591**	**837**	**822**	**794**	393	539	652	1 016
Segmented net income (millions of dollars)								
Natural resources	**397**	**754**	**617**	**608**	276	469	592	671
Petroleum products	**199**	**62**	**149**	**214**	166	94	171	263
Chemicals	**39**	**31**	**38**	**35**	44	33	12	32
Corporate and other	**(44)**	**(10)**	**18**	**(63)**	(93)	(57)	(123)	50
Net income	**591**	**837**	**822**	**794**	393	539	652	1 016
Per-share information (dollars) (c)								
Net earnings – basic	**0.60**	**0.85**	**0.84**	**0.83**	0.38	0.52	0.64	1.00
Net earnings – diluted	**0.59**	**0.85**	**0.84**	**0.83**	0.37	0.52	0.64	1.00
Dividends (declared quarterly)	**0.08**	**0.08**	**0.08**	**0.08**	0.07	0.08	0.08	0.08
Share prices (dollars) (c) (d)								
Toronto Stock Exchange								
High	**42.28**	**43.33**	**45.20**	**44.80**	31.44	34.99	45.79	45.39
Low	**35.36**	**36.18**	**35.33**	**34.31**	22.50	27.37	33.33	32.28
Close	**41.91**	**40.78**	**37.47**	**42.93**	30.67	34.01	44.67	38.47
American Stock Exchange ($U.S.)								
High	**36.67**	**39.64**	**40.38**	**38.93**	25.73	28.38	39.14	38.93
Low	**30.54**	**32.50**	**31.64**	**29.99**	18.27	21.57	27.46	27.47
Close	**35.85**	**36.50**	**33.55**	**36.83**	25.38	27.75	38.35	33.20
Shares traded (thousands) (c) (e)	**99 309**	**77 793**	**70 701**	**73 442**	77 946	89 001	91 785	98 904

(a) Quarterly data has not been audited by the company's independent auditors.
(b) Amounts for purchases/sales with the same counterparty are included in both revenues and expenses in 2005 quarterly data. Effective January 1, 2006, these purchases/sales were recorded on a net basis.
(c) Adjusted to reflect the three-for-one share split.
(d) Imperial's shares are listed on the Toronto Stock Exchange and are admitted to unlisted trading on the American Stock Exchange in New York. The symbol on these exchanges for Imperial's common shares is IMO. Share prices were obtained from stock exchange records, adjusted for the three-for-one share split.
(e) The number of shares traded is based on transactions on the above stock exchanges.

Dividend and share purchase information

	2nd quarter, 2007	**3rd quarter, 2007**	**4th quarter, 2007**	**1st quarter, 2008**
Declaration date	May 22, 2007	August 28, 2007	November 20, 2007	January 31, 2008
Dividend record date	June 6, 2007	September 10, 2007	November 30, 2007	March 3, 2008
Dividend payment date	July 1, 2007	October 1, 2007	January 1, 2008	April 1, 2008
Share purchase cutoff date (cheques for share purchase must be dated and received no later than)	June 15, 2007	September 17, 2007	December 13, 2007	March 17, 2008
Investment date (dividend reinvestment and share purchase funds are invested by the company on)	July 3, 2007	October 2, 2007	January 2, 2008	April 2, 2008

The declaration of dividends and the dates shown are subject to change by the board of directors.
The company reserves the right to amend, suspend or terminate the dividend reinvestment and share purchase plan at any time.
Share purchase cheques should be made payable to CIBC Mellon Trust Company.
Dividend cheques are normally mailed three to five days prior to payment dates.
Quarterly statements for dividend reinvestment and share purchase plan participants are normally mailed two weeks after the investment dates.

Information for investors

Head office

Imperial Oil Limited
P.O. Box 2480, Station 'M'
Calgary, Alberta, Canada T2P 3M9

Annual meeting

The annual meeting of shareholders will be held on Tuesday, May 1, 2007, at 9:30 a.m. local time at the TELUS Convention Centre, North Building, Upper Level, 136 Eighth Avenue S.E., Calgary, Alberta, Canada.

Shareholder account matters

To change your address, transfer shares, eliminate multiple mailings, elect to receive dividends in U.S. funds, have dividends deposited directly into accounts at financial institutions in Canada that provide electronic fund-transfer services, enrol in the dividend reinvestment and share purchase plan, or enrol for electronic delivery of shareholder reports, please contact Imperial's transfer agent, CIBC Mellon Trust Company.

CIBC Mellon Trust Company
P.O. Box 7010
Adelaide Street Postal Station
Toronto, Ontario, Canada M5C 2W9
Telephone: 1-800-387-0825 (from Canada or U.S.A.)
or 416-643-5500
Fax: 416-643-5501
E-mail: inquiries@cibcmellon.com
www.cibcmellon.com

United States resident shareholders may transfer their shares through Mellon Investor Services LLC.

Mellon Investor Services LLC
480 Washington Boulevard
Jersey City, New Jersey, U.S.A. 07310-1900
Telephone: 1-800-526-0801

Dividend reinvestment and share-purchase plan

This plan provides shareholders with two ways to add to their shareholdings at a reduced cost. The plan enables shareholders to reinvest their cash dividends in additional shares at an average market price. Shareholders can also invest between $50 and $5,000 each calendar quarter in additional shares at an average market price.

Funds directed to the dividend reinvestment and share-purchase plan are used to buy existing shares on a stock exchange rather than newly issued shares.

Imperial online

Imperial's website contains a variety of corporate and investor information, including:

- current stock prices
- annual and interim reports
- Form 10-K
- Information for Investors (a factbook that describes the company and its operations in detail)
- investor presentations
- earnings and other news releases
- historical dividend information
- corporate citizenship practices

www.imperialoil.ca

Investor information

Information is also available by writing to the investor relations manager at Imperial's head office or by:

Telephone: 403-237-4538
Fax: 403-237-2081

Other contact numbers

Customer and other inquiries:
Telephone: 1-800-567-3776
Fax: 1-800-367-0585

Corporate secretary
Telephone: 403-237-2915
Fax: 403-237-2490

Version française du rapport

Pour obtenir la version française du rapport de la Compagnie Pétrolière Impériale Ltée, veuillez écrire à la division des Relations avec les investisseurs, Compagnie Pétrolière Impériale Ltée, P.O. Box 2480 Station 'M', Calgary, Alberta, Canada T2P 3M9.

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Calgary, Alberta

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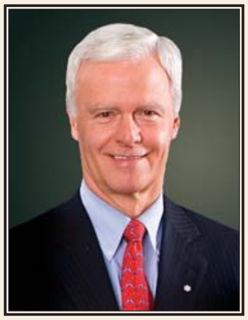

Victor L. Young
Corporate director of several corporations
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Vice-president, general counsel and corporate secretary

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J.F. Shepard, *director*
S.D. Whittaker, *director*
V.L. Young, *director*

Left: Dartmouth refinery – the first in Atlantic Canada – has been operating in Dartmouth for almost 90 years.

Cover: On site at Cold Lake's state-of-the-art water treatment facilities.

Since the Cold Lake heavy oil operation was conceived in the 1960s, Imperial has continued to develop and refine techniques for treating and recycling the water that is produced along with the oil.

Cold Lake achieved record production in 2006.

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