IMPERIAL OIL LTD
Form 10-K
February 25, 2011
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE

SECURITIES EXCHANGE ACT OF 1934

For the fiscal year-ended December 31, 2010 **Commission file number: 0-12014**

IMPERIAL OIL LIMITED

(Exact name of registrant as specified in its charter)

CANADA	**98-0017682**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
237 FOURTH AVENUE S.W., CALGARY, AB, CANADA	**T2P 3M9**
(Address of principal executive offices)	**(Postal Code)**

Registrant s telephone number, including area code:

1-800-567-3776

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
None	None

Securities registered pursuant to Section 12(g) of the Act:

Common Shares (without par value)

(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer (as defined in Rule 405 of the Securities Exchange Act of 1934).

Yes ü No......

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934.

Yes ......No ü

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ü No......

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate web site, if any, every interactive data file required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yesü No......

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Yes ü No......

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (see the definitions of large accelerated filer , accelerated filer and smaller reporting company in Rule 12b-2 of the Securities Exchange Act of 1934).

Large accelerated filer ü Accelerated filer...... Non-accelerated filer...... Smaller reporting company......

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12 b-2 of the Securities Exchange Act of 1934).

Yes ......No ü

As of the last business day of the 2010 second fiscal quarter, the aggregate market value of the voting stock held by non-affiliates of the registrant was Canadian $9,992,470,056 based upon the reported last sale price of such stock on the Toronto Stock Exchange on that date.

The number of common shares outstanding, as of February 11, 2011, was 847,607,765.

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All dollar amounts set forth in this report are in Canadian dollars, except where otherwise indicated.

Note that numbers may not add due to rounding.

The following table sets forth (i) the rates of exchange for the Canadian dollar, expressed in United States (U.S.) dollars, in effect at the end of each of the periods indicated, (ii) the average of exchange rates in effect on the last day of each month during such periods, and (iii) the high and low exchange rates during such periods, in each case based on the noon buying rate in New York City for wire transfers in Canadian dollars as certified for customs purposes by the Federal Reserve Bank of New York.

dollars	**2010**	2009	2008	2007	2006
Rate at end of period	**0.9991**	0.9559	0.8170	1.0120	0.8582
Average rate during period	**0.9659**	0.8793	0.9335	0.9376	0.8844
High	**1.0040**	0.9719	1.0291	1.0908	0.9100
Low	**0.9280**	0.7695	0.7710	0.8437	0.8528

On February 11, 2011, the noon buying rate in New York City for wire transfers in Canadian dollars as certified for customs purposes by the Federal Reserve Bank of New York was $1.0101 U.S. = $1.00 Canadian.

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Forward-looking statements

Statements in this report regarding expectations, plans and future events or conditions are forward-looking statements. Actual future results, including demand growth and energy source mix; production growth and mix; project start-ups; the effect of changes in prices and other market conditions; financing sources; and capital and environmental expenditures could differ materially depending on a number of factors, such as changes in the supply of and demand for crude oil, natural gas, and petroleum and petrochemical products; political or regulatory events; project schedules; commercial negotiations; and other factors discussed in Item 1A of this annual report on Form 10-K and in the management s discussion and analysis of financial condition and results of operations contained in Item 7.

PART I

Item 1. Business

Imperial Oil Limited was incorporated under the laws of Canada in 1880 and was continued under the Canada Business Corporations Act (the CBCA) by certificate of continuance dated April 24, 1978. The head and principal office of the company is located at 237 Fourth Avenue S.W. Calgary, Alberta, Canada T2P 3M9; telephone 1-800-567-3776. Exxon Mobil Corporation owns approximately 69.6 percent of the outstanding shares of the company. In this report, unless the context otherwise indicates, reference to the company or Imperial includes Imperial Oil Limited and its subsidiaries.

The company is one of Canada s largest integrated oil companies. It is active in all phases of the petroleum industry in Canada, including the exploration for, and production and sale of, crude oil and natural gas. In Canada, it is a major producer of crude oil and natural gas and the largest petroleum refiner and a leading marketer of petroleum products. It is also a major supplier of petrochemicals.

Financial information by operating segments (under U.S. GAAP)

millions of dollars	**2010**	2009	2008	2007	2006
Operating revenues:					
Upstream	**4,283**	3,552	5,819	4,539	4,619
Downstream	**19,565**	16,793	24,049	19,230	18,527
Chemical	**1,098**	947	1,372	1,300	1,359
	24,946	21,292	31,240	25,069	24,505
Intersegment sales:					
Upstream	**3,802**	3,328	5,403	4,146	3,837
Downstream	**1,973**	1,535	2,892	2,305	2,256
Chemical	**285**	289	460	335	345
Net income (a):					
Upstream	**1,764**	1,324	2,923	2,369	2,376
Downstream	**442**	278	796	921	624
Chemical	**69**	46	100	97	143
Corporate and other (b)	**(65)**	(69)	59	(199)	(99)
	2,210	1,579	3,878	3,188	3,044
Identifiable assets at December 31 (c):					
Upstream	**13,852**	10,663	8,758	8,171	7,513

Downstream	**6,315**	6,183	6,038	6,727	6,450
Chemical	**425**	428	431	476	504
Corporate and other / eliminations	**(12)**	199	1,808	913	1,674
	20,580	17,473	17,035	16,287	16,141
Capital and exploration expenditures:					
Upstream	**3,844**	2,167	1,110	744	787
Downstream	**184**	251	232	187	361
Chemical	**10**	15	13	11	13
Corporate and other	**7**	5	8	36	48
	4,045	2,438	1,363	978	1,209

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Footnotes to the Financial information by operating segments on the preceding page:

(a) These amounts are presented as if each segment were a separate business entity and, accordingly, include the financial effect of transactions between the segments. Intersegment sales are made essentially at prevailing market prices.
(b) Primarily includes interest charges on the debt obligations of the company, interest income and share based incentive compensation expenses.
(c) The identifiable assets in each operating segment represent the net book value of the tangible and intangible assets attributed to such segment.

The company s operations are conducted in three main segments: Upstream, Downstream and Chemical. Upstream operations include the exploration for, and production of, conventional crude oil, natural gas, synthetic oil and bitumen. Downstream operations consist of the transportation and refining of crude oil, blending of refined products, and the distribution and marketing of those products. Chemical operations consist of the manufacturing and marketing of various petrochemicals.

Upstream

Summary of oil and gas reserves at year-end

The table below summarizes the net oil-equivalent proved reserves for the company, as at December 31, 2010, as detailed in the Oil and gas reserves part of the Financial section, starting on page 79 of this report.

All of the company s reported reserves are located in Canada. The company has reported proved reserves based on the average of the first-day-of-the-month price for each month during the last 12-month period ending December 31. Natural gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels. No major discovery or other favorable or adverse event has occurred since December 31, 2010 that would cause a significant change in the estimated proved reserves as of that date.

	Liquids (a)	Natural gas	Synthetic oil	Bitumen	Total oil-equivalent basis
	millions of barrels	billions of cubic feet	millions of barrels	millions of barrels	millions of barrels
Net proved reserves:					
Developed	**56**	**507**	**681**	**519**	**1,340**
Undeveloped	**1**	**69**	**-**	**1,196**	**1,209**
Total net proved	**57**	**576**	**681**	**1,715**	**2,549**

(a) Liquids include crude oil, condensate and natural gas liquids (NGLs).

The estimation of proved reserves, which is based on the requirement of reasonable certainty, is an ongoing process based on rigorous technical evaluations, commercial and market assessments and detailed analysis of well information such as flow rates and reservoir pressure declines. Furthermore, the company only records proved reserves for projects which have received significant funding commitments by management made toward the development of the reserves. 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, regulatory approvals and significant changes in projections of long-term oil and gas price levels.

Technologies used in establishing proved reserves estimates

Additions to Imperial s proved reserves in 2010 were based on estimates generated through the integration of available and appropriate data, utilizing well established technologies that have been demonstrated in the field to yield repeatable and consistent results.

Data used in these integrated assessments included information obtained directly from the subsurface via wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data utilized also included subsurface information obtained through indirect measurements, including high-quality 2-D and 3-D seismic data, calibrated with available well control. Where applicable, surface geological information was also utilized. The tools used to interpret the data included proprietary seismic processing software, proprietary reservoir modeling and simulation software and commercially available data analysis packages.

In some circumstances, where appropriate analog reservoirs were available, reservoir parameters from these analogs were used to increase the quality of and confidence in the reserves estimates.

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Preparation of reserves estimates

Imperial has a dedicated reserves management group that is separate from the base operating organization. Primary responsibilities of this group include oversight of the reserves estimation process for compliance with Securities and Exchange Commission (SEC) rules and regulations, review of annual changes in reserves estimates, and the reporting of Imperial s proved reserves. In addition, this group provides training to personnel involved in the reserve estimation and reporting processes within Imperial.

Key components of the reserves estimation process include technical evaluations and analysis of well and field performance and a rigorous peer review. The reserves management group maintains a central computerized database containing the official company reserves estimates and production data. Appropriate controls, including limitations on database access and update capabilities, are in place to ensure data integrity within this central computerized database. An annual review of the system s controls is performed by internal audit. No changes may be made to reserves estimates in the central database, including the addition of any new initial reserves estimates or subsequent revisions, unless those changes have been thoroughly reviewed and evaluated by duly authorized personnel within the base operating organization. In addition, changes to reserves estimates that exceed certain thresholds will require further review and approval of the appropriate level of management within the operating organization, culminating in reviews with and approval by senior management and the company s board of directors.

The Operations Technical Subsurface Engineering Manager, who is an employee of the company, has evaluated the company s reserves data and filed a report to the Canadian securities regulatory authorities. The company s internal reserves evaluation staff consists of about 64 persons with an average of approximately 16 years of relevant experience in evaluating reserves, of whom about 32 persons are qualified reserves evaluators for purposes of Canadian securities regulatory requirements. The company s internal reserves evaluation management team is made up of about 18 persons with an average of approximately 16 years of relevant experience in evaluating and managing the evaluation of reserves. No independent qualified reserves evaluator or auditor was involved in the preparation of the company s reserves data.

Proved undeveloped reserves

As of December 31, 2010, approximately 47 percent of the company s proved reserves were proved undeveloped reserves reflecting volumes of 1,209 million oil-equivalent barrels. Nearly all of those undeveloped reserves are associated with either the Kearl project or Cold Lake field. This compared to approximately 48 percent or 1,204 million oil-equivalent barrels of proved undeveloped reserves reported at the end of 2009.

One of the company s requirements to report resources as proved reserves is that management has made significant funding commitments towards the development of the reserves. The company has a disciplined investment strategy and many major fields require a significant lead-time in order to be developed. The company made investments of about $3.0 billion during the year to progress the development of reported proved undeveloped reserves. The Kearl project is currently under development. Proved undeveloped reserves at Cold Lake are associated with the ongoing drilling program. In 2010, Imperial moved 52 million barrels from proved undeveloped to proved developed reserves at Cold Lake.

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Oil and gas production, production prices and production costs

The company s average daily oil production by final products sold during the three years ended December 31, 2010, was as follows. All reported production volumes were from Canada.

thousands of barrels a day		**2010**	2009	2008
Liquids:	- gross (a)	**30**	33	37
	- net (b)	**22**	26	27
Bitumen (c):	- gross (a)	**144**	141	147
	- net (b)	**115**	120	124
Synthetic oil (d):	- gross (a)	**73**	70	72
	- net (b)	**67**	65	62
Total:	- gross (a)	**247**	244	256
	- net (b)	**204**	211	213

(a) Gross production is the company s share of production (excluding purchases) before deduction of the mineral owners or governments share or both.
(b) Net production is gross production less the mineral owners or governments share or both.
(c) All of the company s bitumen production volumes were from the Cold Lake production operation.
(d) All of the company s synthetic oil production volumes were from the company s share of production volumes in the Syncrude joint venture.

In 2010, planned maintenance activities at the Norman Wells field and natural reservoir decline were the main contributors to the lower liquids production. Higher gross bitumen volumes in 2010 were due to improved facility reliability as well as the cyclic nature of production at Cold Lake. Net bitumen production at Cold Lake was lower due to higher royalties. Synthetic oil production at Syncrude was higher primarily due to improved operational reliability.

In 2009, the most significant reason for lower liquids production volume was natural decline in Western Canada reservoirs. Bitumen production at Cold Lake declined due to the cyclic nature of production and well repairs in the northern part of the field. Drilling and steaming activities have since resumed in this area. Gross synthetic oil production at Syncrude was also lower as planned maintenance activities in the first half of 2009, which included design modifications to improve long-term operational performance, contributed to the reduced production for the full year in 2009. Net synthetic oil production at Syncrude was higher due to lower royalties.

The company s average daily production and sales of natural gas during the three years ended December 31, 2010 are set forth below. All reported production volumes were from Canada. All gas volumes in this report are calculated at a pressure base of 14.73 pounds per square inch absolute at 60 degrees Fahrenheit.

Average daily production and sales of natural gas

millions of cubic feet a day	**2010**	2009	2008
Gross production (a) (b)	**280**	295	310
Net production (c)	**254**	274	249
Sales (d)	**264**	272	288

(a) Gross production is the company s share of production (excluding purchases) before deduction of the mineral owners or governments share or both.
(b) Production of natural gas includes amounts used for internal consumption with the exception of the amounts reinjected.
(c) Net production is gross production less the mineral owners or governments share or both.
(d) Sales are sales of the company s share of production (before deduction of the mineral owners and/or governments share) and sales of gas purchased, processed and/or resold.

In 2010, lower gross gas production volume was primarily a result of natural reservoir decline and maintenance activities.

In 2009, the lower gross gas production volume was primarily a result of natural reservoir decline. Net production volumes were higher due to lower royalties.

The company s total average daily production expressed in oil-equivalent basis is set forth below, with natural gas converted to an oil-equivalent basis at six million cubic feet per one thousand barrels.

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Total average daily oil-equivalent basis production

thousands of barrels a day	**2010**	2009	2008
Total production oil-equivalent basis:			
- gross (a)	**294**	293	308
- net (b)	**246**	257	255

(a) Gross production is the company s share of production (excluding purchases) before deduction of the mineral owners or governments share or both.
(b) Net production is gross production less the mineral owners or governments share or both.

The company s average unit sales price and average unit production costs by product type for the three years ended December 31, 2010, were as follows:

Average unit sales price

dollars a barrel	**2010**	2009	2008
Liquids	**65.84**	53.91	84.67
Synthetic oil	**80.63**	69.69	106.61
Bitumen	**58.36**	51.81	69.04
dollars per thousand cubic feet			
Natural gas	**4.04**	4.11	8.69

Average unit production costs

dollars a barrel	**2010**	2009	2008
Synthetic oil	**45.17**	43.95	45.10
Bitumen	**18.43**	17.17	21.09
Total oil-equivalent basis (a)	**24.76**	23.66	25.25

(a) Includes liquids, bitumen, synthetic oil and natural gas.

Canadian crude oil prices are mainly determined by international crude oil markets and the impact of foreign exchange rates.

Canadian natural gas prices are determined by North American gas markets and the impact of foreign exchange rates.

In 2010, unit production costs increased on a net basis primarily due to lower net volumes as a result of higher royalty costs.

In 2009, unit production costs decreased on a net basis. Higher net volumes due to lower price sensitive royalties more than offset increased spending.

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Drilling and other exploratory and development activities

The company has been involved in the exploration for and development of petroleum and natural gas in Canada only.

The following table sets forth the conventional and bitumen net exploratory and development wells that were drilled or participated in by the company during the three years ending December 31, 2010.

wells	**2010**	2009	2008
Net productive exploratory:			
Oil and gas	**6**	2	
Bitumen			
Net dry exploratory:			
Oil and gas			
Bitumen			
Net productive development:			
Oil and gas	**73**	218	147
Bitumen	**110**	60	70
Net dry development:			
Oil and gas			
Bitumen			
Total	**189**	280	217

In 2010, 110 bitumen development wells were drilled to add new productive capacity from undeveloped areas of existing phases at Cold Lake. In addition, 71 gas development wells were drilled in 2010 adding productivity primarily in the shallow gas area. Additionally, one oil development well was drilled in Norman Wells and one oil development well was drilled in the Pembina area.

Also in 2010, six net exploratory gas wells were drilled in the Horn River shale gas play, as part of the company s ongoing evaluation of its holdings in the area.

In 2009, 60 bitumen development wells were drilled to add new productive capacity from undeveloped areas of existing phases at Cold Lake. In addition, 216 gas development wells were drilled in 2009 adding productivity primarily in the shallow gas area. Additionally, two oil development wells were drilled in Norman Wells. Also in 2009, two net exploratory gas wells were drilled in the Horn River shale gas play as part of the company s ongoing evaluation of its holdings in the area.

In 2008, 70 bitumen development wells were drilled to add new productive capacity from undeveloped areas of existing phases at Cold Lake. In addition, 146 gas development wells were drilled in 2008 adding productivity primarily in the shallow gas area. Additionally, one oil development well was drilled in Norman Wells.

Wells drilling

At December 31, 2010, the company was participating in the drilling of the following exploratory and development wells. All wells were located in Canada.

	2010	
wells	Gross	Net
Oil and gas	**86**	**24**
Bitumen	**5**	**5**

Total	**91**	**29**

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Exploratory and development activities regarding oil and gas resources

Cold Lake

To maintain production at Cold Lake, capital expenditures for additional production wells and associated facilities are required periodically. In 2010, the company executed a development drilling program of 110 wells on existing phases.

In 2011, a development drilling program is planned within the approved development area to add productive capacity from undeveloped areas of existing Cold Lake phases. In addition, planning, design and early site work are progressing on the Nabiye project, the next phase of expansion at Cold Lake, which has the potential to add about 30,000 barrels a day of production before royalties.

The company also conducts experimental pilot operations to improve recovery of bitumen from wells by means of new drilling and production techniques.

Western provinces

In 2010, a 12-well (gross) winter exploration drilling program at the company s Horn River shale gas acreage was completed. Work is underway on a pad pilot development to evaluate longer-term well productivity and cost.

Mackenzie Delta

In 1999, the company and three other companies entered into an agreement to study the feasibility of developing Mackenzie Delta gas, anchored by three large onshore natural gas fields. The company retains a 100 percent interest in the largest of these fields.

The commercial viability of these natural gas resources, and the pipeline required to transport this natural gas to markets, is dependent on a number of factors. These factors include natural gas markets, support from northern parties, regulatory approvals, environmental considerations, pipeline participation, fiscal framework and the cost of constructing, operating and abandoning the field production and pipeline facilities.

In October 2004, the company and its co-venturers filed regulatory applications and environmental impact statements for the project with the National Energy Board (NEB) and other boards, panels and agencies responsible for assessing and regulating energy developments in the Northwest Territories. All the scheduled public hearings by the Joint Review Panel (JRP) and the NEB were concluded in late 2007. The JRP report was released in late 2009. In late 2010, the NEB announced its approval of plans to build and operate the project, subject to federal cabinet approval and 264 conditions in areas such as engineering, safety and environmental protection.

Beaufort Sea

In 2007, the company acquired a 50 percent interest in an exploration licence in the Beaufort Sea. As part of the evaluation, a 3-D seismic survey was conducted in 2008. In 2009, the company began a data collection program to support environmental studies and safe exploration drilling operations.

In 2010, the company executed an agreement to cross-convey interests with another company to acquire a 25 percent interest in an additional Beaufort Sea exploration licence. As a result of that agreement, the company s interest in its original licence was reduced to 25 percent.

Atlantic offshore

The company holds a 15 percent interest in deepwater exploration blocks in the Orphan Basin, located off the east coast of Newfoundland. In 2004 and 2005, the company participated in 3-D seismic surveys in this area. Exploration wells were drilled in 2007 and 2010. In 2009, the company participated in a remote reservoir resistivity survey of the area.

Other oil sands activity

The company also has interests in other oil sands leases in the Athabasca and Peace River areas of northern Alberta. Evaluation wells completed on these leased areas established the presence of bitumen. The company continues to evaluate these leases to determine their potential for future development.

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Exploratory and development activities regarding oil and gas resources extracted by mining methods

Kearl project

The company holds a 70.96 percent participating interest in the Kearl oil sands project, a joint venture with ExxonMobil Canada Properties, a subsidiary of Exxon Mobil Corporation. The Kearl project will recover shallow deposits of oil sands using open-pit mining methods. The project is located approximately 40 miles north of Fort McMurray, Alberta.

Kearl is expected to be developed in phases. Production from the initial phase is expected to be at an initial rate of approximately 110,000 barrels of bitumen a day, before royalties, of which the company s share would be about 78,000 barrels a day. Bitumen from the Kearl project will be extracted from oil sands produced from open-pit mining operations and processed through a bitumen extraction and froth treatment plant. The product, a blend of bitumen and diluent, is planned to be shipped via pipelines for distribution to North American markets. Diluent is natural gas condensate or other light hydrocarbons added to the crude bitumen to facilitate transportation to market by pipeline.

The Kearl project received approvals from the Province of Alberta in 2007 and the Government of Canada in 2008. The Province of Alberta issued an operating and construction licence in 2008, which permits the project to mine oil sands and produce bitumen from approved development areas on oil sands leases.

At the end of 2010, the initial development of the Kearl project was more than 50 percent complete with expected start up in late 2012.

Kearl will be subject to the revised Alberta generic oil sands royalty regime, which took effect in 2009. Royalty rates are based upon a sliding scale determined by the price of crude oil.

Other oil sands activity

The company is continuing to evaluate other undeveloped, mineable oil sands acreage in the Athabasca region.

Present activities

Review of principal ongoing activities

Cold Lake

During 2010, average net production at Cold Lake was about 115,000 barrels a day and gross production was about 144,000 barrels a day.

Most of the production from Cold Lake is sold to refineries in the northern U.S. The majority of the remainder of Cold Lake production is shipped to certain of the company s refineries and to third-party Canadian refineries.

The Province of Alberta, in its capacity as lessor of Cold Lake oil sands leases, is entitled to a royalty on production at Cold Lake. Cold Lake is subject to the revised Alberta generic oil sands royalty regime, which took effect in 2009. Royalty rates are based upon a sliding scale determined by the price of crude oil.

Syncrude operations

The company holds a 25 percent participating interest in Syncrude, a joint venture established to recover shallow deposits of oil sands using open-pit mining methods to extract the crude bitumen, and to produce a high-quality, light (32 degree API), sweet, synthetic crude oil. The Syncrude operation, located near Fort McMurray, Alberta, mines a portion of the Athabasca oil sands deposit. The produced synthetic crude oil is shipped from the Syncrude site to Edmonton, Alberta by Alberta Oil Sands Pipeline Ltd.

In 2010, Syncrude s net production of synthetic crude oil was about 268,000 barrels a day and gross production was about 293,000 barrels a day. The company s share of net production in 2010 was about 67,000 barrels a day.

There are no approved plans for major future expansion projects.

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In November 2008, Imperial, along with the other Syncrude joint-venture owners, signed an agreement with the Government of Alberta to amend the existing Syncrude Crown Agreement. Under the amended agreement, starting in 2010 and through 2015 Syncrude will pay the existing Crown royalty rates plus an incremental royalty, the amount of which will be subject to minimum production thresholds, before transitioning to the new generic royalty framework in 2016. Also, beginning January 1, 2009, Syncrude s royalty is based on bitumen value with upgrading costs and revenues excluded from the calculation.

On May 1, 2007, the company implemented a management services agreement under which Syncrude will be provided with operational, technical and business management services from Imperial and Exxon Mobil Corporation. The agreement has an initial term of 10 years, automatically renews for successive five-year periods and may be terminated with at least two years prior written notice.

Conventional oil and gas

The company s largest conventional oil producing asset is the Norman Wells oil field in the Northwest Territories, which currently accounts for approximately 66 percent of the company s net production of conventional crude oil (approximately 68 percent of gross production). In 2010, net production of crude oil from Norman Wells was about 12,000 barrels a day and gross production was about 16,000 barrels a day. The Government of Canada has a one-third carried interest and receives a production royalty of five percent in the Norman Wells oil field. The Government of Canada s carried interest entitles it to receive payment of a one-third share of an amount based on revenues from the sale of Norman Wells production, net of operating and capital costs. Under a shipping agreement, the company pays for the construction, operating and other costs of the 540-mile pipeline, which transports the crude oil and natural gas liquids from the project. In 2010, those costs were about $33 million.

Most of the company s larger oil fields in the Western provinces have been in production for several decades, and the amount of oil that is produced from conventional fields is declining.

The company produces natural gas from a large number of gas fields located in the Western provinces, primarily in Alberta. The company also has a nine percent interest in a project to develop and produce natural gas reserves in the Sable Island area off the coast of the Province of Nova Scotia.

Delivery commitments

The company has no material commitments to provide a fixed and determinable quantity of oil or gas in the near future under existing contracts or agreements.

Oil and gas properties, wells, operations, and acreage

Production wells

The company s production of liquids, bitumen and natural gas is derived from wells located exclusively in Canada. The total number of wells capable of production, in which the company had interests at December 31, 2010 and 2009, is set forth in the following table. The statistics in the table are determined in part from information received from other operators.

	Year-ended December 31, 2010				Year-ended December 31, 2009			
	Crude oil		Natural gas		Crude oil		Natural gas	
wells	Gross (a)	Net (b)	Gross (a)	Net (b)	Gross (a)	Net (b)	Gross (a)	Net (b)
Oil and gas (c)	**883**	**588**	**5,372**	**2,833**	937	627	5,479	2,894
Bitumen (c)	**4,358**	**4,358**			4,028	4,028		

(a) Gross wells are wells in which the company owns a working interest.
(b) Net wells are the sum of the fractional working interests owned by the company in gross wells, rounded to the nearest whole number.
(c) Multiple completion wells are permanently equipped to produce separately from two or more distinctly different geological formations. At year-end 2010, the company had an interest in four gross wells with multiple completions (2009 - four gross wells).

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Land holdings

At December 31, 2010 and 2009, the company held the following oil and gas rights, bitumen and synthetic oil leases, all of which are located in Canada, specifically in the Western provinces, in the Canada lands and in the Atlantic offshore:

		Acres					
		Developed		Undeveloped		Total	
thousands of acres		**2010**	2009	**2010**	2009	**2010**	2009
Western provinces:							
Liquids and gas	- gross (a)	**2520**	2,590	**592**	568	**3112**	3,158
	- net (b)	**983**	986	**323**	318	**1306**	1,304
Bitumen	- gross (a)	**103**	103	**645**	645	**748**	748
	- net (b)	**103**	103	**373**	373	**476**	476
Synthetic oil	- gross (a)	**114**	114	**139**	139	**253**	253
	- net (b)	**28**	28	**35**	35	**63**	63
Canada lands (c):							
Liquids and gas	- gross (a)	**4**	37	**1871**	1,343	**1875**	1,380
	- net (b)	**2**	5	**500**	499	**502**	504
Atlantic offshore:							
Liquids and gas	- gross (a)	**65**	65	**4469**	4,469	**4534**	4,534
	- net (b)	**6**	6	**673**	673	**679**	679
Total (d):	- gross (a)	**2806**	2,909	**7716**	7,164	**10522**	10,073
	- net (b)	**1122**	1,128	**1904**	1,898	**3026**	3,026

(a) Gross acres include the interests of others.
(b) Net acres exclude the interests of others.
(c) Canada lands include the Arctic Islands, Beaufort Sea/Mackenzie Delta, and other Northwest Territories, Nunavut and Yukon regions.
(d) Certain land holdings are subject to modification under agreements whereby others may earn interests in the company s holdings by performing certain exploratory work (farm-out) and whereby the company may earn interests in others holdings by performing certain exploratory work (farm-in).

Western provinces

The company s bitumen leases include about 194,000 acres of oil sands leases near Cold Lake and an area of about 34,000 net acres at Kearl. The company has about 77,000 net acres of undeveloped, mineable oil sands acreage in the Athabasca region. In addition, the company also has interests in other bitumen oil sands leases in the Athabasca and Peace River areas totaling about 170,000 net acres.

The company s share of Syncrude joint-venture leases covering about 63,000 net acres accounts for the entire synthetic oil acreage.

The company holds interest in an additional 1,306,000 net acres of developed and undeveloped land in Western Canada related to conventional oil and natural gas. Included in this number is a total acreage position of about 173,000 net acres at Horn River, British Columbia. In 2010, the company added about 18,000 net acres at Horn River.

Canada lands

In the Arctic Islands, the company has an interest in 16 Significant Discovery Licences granted by the Government of Canada. These licences are managed by another company on behalf of all participants and total about 50,000 net acres. In 2010, one production licence was terminated (about 3,000 gross acres). The company has not participated in wells drilled in this area since 1984.

In 2010, about 33,000 developed gross acres and about 3,000 developed net acres were relinquished.

Also within the Canada lands, the company holdings in the Mackenzie Delta include majority interests in 21, and minority interests in six, Significant Discovery Licences granted by the Government of Canada, as the result of previous oil and gas discoveries, all of which are managed by the company, and majority interests in two, and minority interests in 17, other Significant Discovery Licences managed by others. Total acreage held in the Mackenzie Delta is 184,000 net acres.

In 2007, the company acquired a 50 percent interest in an offshore exploration licence in the Beaufort Sea of about 507,000 gross acres. In 2010, the company reduced its interest to 25 percent and acquired a 25 percent interest in another Beaufort Sea exploration licence as part of a cross-conveyance agreement, of about 500,000 gross acres. The company holds interest in the Beaufort Sea of about 252,000 net acres.

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Atlantic offshore

The company manages five Significant Discovery Licences granted by the Government of Canada in the Atlantic offshore. The company also has minority interests, managed by others, in 27 Significant Discovery Licences, and six production licences.

In early 2004, the company acquired a 25 percent interest in eight deep-water exploration licences offshore Newfoundland in the Orphan Basin for about 5,251,000 gross acres. In February 2005, the company reduced its interest to 15 percent through an agreement with another company. In early 2009, one exploration licence in its entirety and most of a second exploration licence, for about 1,069,000 gross acres, expired. The remaining exploration licences were consolidated into two exploration licences, for a total of about 627,000 net acres.

Downstream

Supply

To supply the requirements of its own refineries and condensate requirements for blending with crude bitumen, the company supplements its own production with substantial purchases from others.

The company purchases domestic crude oil at freely negotiated prices from a number of sources. Domestic purchases of crude oil are generally made under renewable contracts with 30 to 60 day cancellation terms.

Crude oil from foreign sources is purchased by the company at market prices mainly through Exxon Mobil Corporation (which has beneficial access to major market sources of crude oil throughout the world).

Refining

The company owns and operates four refineries. The Strathcona refinery operates lubricating oil production facilities. The Strathcona refinery processes Canadian crude oil, and the Dartmouth, Sarnia and Nanticoke refineries process a combination of Canadian and foreign crude oil. In addition to crude oil, the company purchases finished products to supplement its refinery production.

In 2010, capital expenditures of about $100 million were made at the company s refineries. Capital expenditures focused mainly on refinery projects to improve reliability, feedstock flexibility, energy efficiency and environmental performance. The approximate average daily volumes of refinery throughput during the five years ended December 31, 2010, and the daily rated capacities of the refineries at December 31, 2010 and 2005, were as follows:

	Refinery throughput (a) Year-ended December 31					Rated capacities at (b) December 31	
thousands of barrels a day	**2010**	2009	2008	2007	2006	**2010**	2005
Strathcona, Alberta	**168**	145	155	170	160	**187**	187
Sarnia, Ontario	**102**	100	108	103	111	**121**	121
Nanticoke, Ontario	**104**	94	107	100	94	**112**	112
Dartmouth, Nova Scotia	**70**	74	76	69	77	**82**	82
Total	**444**	413	446	442	442	**502**	502

(a) Refinery throughput is the volume of crude oil and feedstocks that is processed in the refinery atmospheric distillation units.

(b) Rated capacities are based on definite specifications as to types of crude oil and feedstocks that are processed in the refinery atmospheric distillation units, the products to be obtained and the refinery process, adjusted to include an estimated allowance for normal maintenance shutdowns. Accordingly, actual capacities may be higher or lower than rated capacities due to changes in refinery operation and the type of crude oil available for processing.

Refinery throughput was 88 percent of capacity in 2010, six percent higher than the previous year. Improved reliability and lower maintenance impacts plus improved market conditions allowed a higher crude throughput to be achieved.

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Distribution

The company maintains a nation-wide distribution system, including 23 primary terminals, to handle bulk and packaged petroleum products moving from refineries to market by pipeline, tanker, rail and road transport. The company owns and operates natural gas liquids and products pipelines in Alberta, Manitoba and Ontario and has interests in the capital stock of one crude oil and two products pipeline companies.

Marketing

The company markets more than 630 petroleum products throughout Canada under well known brand names, most notably Esso and Mobil, to all types of customers.

The company sells to the motoring public through Esso retail service stations. On average during the year, there were about 1,850 retail service stations, of which about 510 were company owned or leased, but none of which were company operated. The company continues to improve its Esso retail service station network, providing more customer services such as car washes and convenience stores, primarily at high volume sites in urban centres.

The Canadian farm, residential heating and small commercial markets are served through about 80 sales facilities. The company also sells petroleum products to large industrial and commercial accounts as well as to other refiners and marketers.

The approximate daily volumes of net petroleum products (excluding purchases/sales contracts with the same counterparty) sold during the five years ended December 31, 2010, are set out in the following table:

thousands of barrels a day	**2010**	2009	2008	2007	2006
Gasolines	**218**	200	204	208	206
Heating, diesel and jet fuels	**153**	143	157	164	166
Heavy fuel oils	**28**	27	30	33	32
Lube oils and other products	**43**	39	47	43	49
Net petroleum product sales	**442**	409	438	448	453

The total domestic sales of petroleum products, as a percentage of total sales of petroleum products during the five years ended December 31, 2010, were as follows:

percentage	**2010**	2009	2008	2007	2006
Domestic petroleum product sales as a percentage of total petroleum product sales volumes	**92.8**	90.3	93.0	94.8	95.1

The company continues to evaluate and adjust its Esso retail service station and distribution system to increase productivity and efficiency. During 2010, the company closed or debranded about 60 Esso retail service stations, about 15 of which were company owned, and added about 60 sites. The company s average annual throughput in 2010 per Esso retail service station was about 25 thousand barrels (4.0 million litres), an increase of about one thousand barrels (0.1 million litres). Average throughput per company owned or leased Esso retail service station was about 45 thousand barrels (7.2 million litres) in 2010, an increase of about one thousand barrels (0.2 million litres) from 2009.

Total downstream capital expenditures were $184 million in 2010 and are expected to be about $175 million in 2011.

Chemical

The company s Chemical operations manufacture and market ethylene, benzene, aromatic and aliphatic solvents, plasticizer intermediates and polyethylene resin. Its major petrochemical and polyethylene manufacturing operations are located in Sarnia, Ontario, adjacent to the company s petroleum refinery. There is also a heptene and octene plant located in Dartmouth, Nova Scotia.

The company s total sales volumes of petrochemicals during the five years ended December 31, 2010, were as follows:

thousands of tonnes	**2010**	2009	2008	2007	2006
Total sales of petrochemicals	**989**	1,026	1,021	1,121	1,085

Lower volumes in 2010 were primarily due to planned maintenance work at the Sarnia facility, which included an expansion of Sarnia s flexibility to crack alternative feedstocks.

Capital expenditures in 2010 were $10 million, with planned expenditures in 2011 of about $10 million.

Research

In 2010, the company s total research expenditures, before deduction of investment tax credits, were about $109 million, as compared with $116 million in 2009, and $144 million in 2008. Total research expenditures included capital expenditures of $3 million, $19 million and $62 million in 2010, 2009 and 2008, respectively. These expenditures were used mainly for developing improved crude bitumen recovery methods and refinery processes, and supporting the lubricants business, as well as accessing ExxonMobil s data worldwide.

A research facility to support the company s Upstream operations is located in Calgary, Alberta. Research in these laboratories is aimed at developing new technology for the production and processing of crude bitumen. About 40 people were involved in this type of research in 2010. The company also participated in bitumen recovery and processing research for oil sands development through its interest in Syncrude, which maintains research facilities in Edmonton, Alberta and through research arrangements with others.

In company laboratories in Sarnia, Ontario, research and advanced technical support is mainly conducted on the development and support of lubricants and fuels products and processes. About 105 people were employed in this type of research and advanced technical support at the end of 2010. Also in Sarnia, there are about seven people engaged in new product development for the company s and Exxon Mobil Corporation s polyethylene injection and rotational molding businesses.

The company has scientific research agreements with affiliates of Exxon Mobil Corporation, which provide for technical and engineering work to be performed by all parties, the exchange of technical information and the assignment and licensing of patents and patent rights. These agreements provide mutual access to scientific and operating data related to nearly every phase of the petroleum and petrochemical operations of the parties.

Environmental protection

The company is concerned with and active in protecting the environment in connection with its various operations. The company works in cooperation with government agencies, industry associations and communities to deal with existing, and to anticipate potential, environmental protection issues. In the past five years, the company has made capital and operating expenditures of about $3.1 billion on environmental protection and facilities. In 2010, the company s environmental capital and operating expenditures totaled approximately $708 million, which was spent primarily on emissions reductions at company owned facilities and Syncrude, remediation of idled facilities and operations, as well as on protection of freshwater near Imperial facilities. Capital and operating expenditures relating to environmental protection are expected to be about $675 million in 2011.

Human resources

At December 31, 2010, the company employed about 4,970 persons on a full-time basis, compared with about 5,015 at the end of 2009 and about 4,850 at the end of 2008. About nine percent of the company s employees are members of unions. The company continues to maintain a broad range of benefits, including health, dental, disability and survivor benefits, vacation, savings plan and pension plan.

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Competition

The Canadian petroleum, natural gas and chemical industries are highly competitive. Competition exists in the search for and development of new sources of supply, the construction and operation of crude oil, natural gas and refined products pipelines and facilities and the refining, distribution and marketing of petroleum products and chemicals. The petroleum industry also competes with other industries in supplying energy, fuel and other needs of consumers.

Government regulation

Petroleum and natural gas rights

Most of the company s petroleum and natural gas rights were acquired from governments, either federal or provincial. Reservations, permits or licences are acquired from the provinces for cash and entitle the holder to obtain leases upon completing specified work. Leases may also be acquired for cash. A lease entitles the holder to produce petroleum and/or natural gas from the leased lands. The holder of a licence relating to Canada lands and the Atlantic Offshore is generally required to make cash payments or to undertake specified work or amounts of exploration expenditures in order to retain the holder s interest in the land and may become entitled to produce petroleum or natural gas from the licenced land.

Crude oil

Production

The maximum allowable gross production of crude oil from wells in Canada is subject to limitation by various regulatory authorities on the basis of engineering and conservation principles.

Exports

Export contracts of more than one year for light crude oil and petroleum products and two years for heavy crude oil (including crude bitumen) require the prior approval of the NEB and the Government of Canada.

Natural gas

Production

The maximum allowable gross production of natural gas from wells in Canada is subject to limitations by various regulatory authorities. These limitations are to ensure oil recovery is not adversely impacted by accelerated gas production practices. These limitations do not impact gas reserves, only the timing of production of the reserves, and did not have a significant impact on 2010 gas production rates.

Exports

The Government of Canada has the authority to regulate the export price for natural gas and has a gas export pricing policy, which accommodates export prices for natural gas negotiated between Canadian exporters and U.S. importers.

Exports of natural gas from Canada require approval by the NEB and the Government of Canada. The Government of Canada allows the export of natural gas by NEB order without volume limitation for terms not exceeding 24 months.

Royalties

The Government of Canada and the provinces in which the company produces crude oil and natural gas impose royalties on production from lands where they own the mineral rights. Some producing provinces also receive revenue by imposing taxes on production from lands where they do not own the mineral rights.

Different royalties are imposed by the Government of Canada and each of the producing provinces. Royalties imposed on crude oil, natural gas and natural gas liquids vary depending on a number of parameters, including well production volumes, selling prices and recovery methods. For information with respect to royalty rates for Norman Wells, Cold Lake, Syncrude and Kearl, see Upstream section under Item 1.

Investment Canada Act

The Investment Canada Act requires Government of Canada approval, in certain cases, of the acquisition of control of a Canadian business by an entity that is not controlled by Canadians. The acquisition of natural resource properties may, in certain circumstances, be considered a transaction that constitutes an acquisition of control of a Canadian business requiring Government of Canada approval.

The Act also requires notification of the establishment of new unrelated businesses in Canada by entities not controlled by Canadians, but does not require Government of Canada approval except when the new business is related to Canada s cultural heritage or national identity. The Government of Canada is also authorized to take any measures that it considers advisable to protect national security, including the outright prohibition of a foreign investment in Canada. By virtue of the majority stock ownership of the company by Exxon Mobil Corporation, the company is considered to be an entity which is not controlled by Canadians.

The company online

The company s website **www.imperialoil.ca** contains a variety of corporate and investor information which is available free of charge, including the company s annual report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K and amendments to these reports, as well as required interactive data filings. These reports are made available as soon as reasonably practicable after they are filed or furnished to the U.S. SEC.

Item 1A. Risk factors

Volatility of oil and natural gas prices

The company s results of operations and financial condition are dependent on the prices it receives for its oil and natural gas production. 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. Disruptions to pipelines linking production to markets may reduce the price for that production or lead to curtailment of production. In the past, crude oil and natural gas prices have been volatile, and the company expects that volatility to continue. Any material decline in oil or natural gas prices could have a material adverse effect on the company s operations, financial condition, proven reserves and the amount spent to develop oil and natural gas reserves.

A significant portion of the company s production is bitumen. The market prices for bitumen differ from the established market indices for light and medium grades of oil principally due to the higher transportation and refining costs associated with bitumen and limited refining capacity capable of processing bitumen. As a result, the price received for bitumen is generally lower than the price for medium and light oil. Future differentials are uncertain and increases in the bitumen differentials could have a material adverse effect on the company s business.

Industry crude oil and natural gas commodity prices and petroleum and chemical product prices are commonly benchmarked in U.S. dollars. The majority of Imperial s sales and purchases are related to these industry U.S. dollar benchmarks. As the company records and reports its financial results in Canadian dollars, to the extent that the Canadian/U.S. dollar exchange rate fluctuates, the company s earnings will be affected.

The company does not use derivative instruments to offset exposures associated with hydrocarbon prices, currency exchange rates and interest rates that arise from existing assets, liabilities and transactions. The company does not engage in speculative derivative activities nor does it use derivatives with leveraged features.

Competitive factors

The oil and gas industry is highly competitive, particularly in the following areas: searching for and developing new sources of supply; constructing and operating crude oil, natural gas and refined products pipelines and facilities; and the refining, distribution and marketing of petroleum products and chemicals. The company s competitors include major integrated oil and gas companies and numerous other independent oil and gas companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to customers.

Competitive forces may result in shortages of prospects to drill, services to carry out exploration, development or operating activities and infrastructure to produce and transport production. It may also result in an oversupply of crude oil, natural gas, petroleum products and chemicals. Each of these factors could have a negative impact on costs and prices and, therefore, the company s financial results.

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Environmental risks

All phases of the Upstream, Downstream and Chemical businesses are subject to environmental regulation pursuant to a variety of Canadian federal, provincial and municipal laws and regulations, as well as international conventions (collectively, environmental legislation).

Environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. As well, environmental regulations are imposed on the qualities and compositions of the products sold and imported. Environmental legislation also requires that wells, facility sites and other properties associated with the company s operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and significant changes to certain existing projects, may require the submission and approval of environmental impact assessments. Compliance with environmental legislation can require significant expenditures and failure to comply with environmental legislation may result in the imposition of fines and penalties and liability for clean up costs and damages. The company cannot assure that the costs of complying with environmental legislation in the future will not have a material adverse effect on its financial condition or results of operations. The company anticipates that changes in environmental legislation may require, among other things, reductions in emissions to the air from its operations and result in increased capital expenditures. Future changes in environmental legislation could occur and result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse effect on the company s financial condition or results of operations.

The company s activities in deep water oil and gas exploration are limited. However, there are operational risks inherent in oil and gas exploration and production activities, as well as the potential to incur substantial financial liabilities if those risks are not effectively managed. The ability to insure such risks is limited by the capacity of the applicable insurance markets, which may not be sufficient to cover the likely cost of a major adverse operating event such as a deepwater well blowout. Accordingly, the company s primary focus is on prevention, including through its rigorous operations integrity management system. The company s future results will depend on the continued effectiveness of these efforts.

Climate change

In April 2007, the Government of Canada announced its intent to introduce a set of regulations to limit emissions of greenhouse gas and air pollutants from major industrial facilities in Canada, although the details of the regulations have not been finalized. In the fall of 2009, the Government further expressed its intent that Canadian policy in this area be aligned with that of the U.S., which also remains under development. Consequently, attempts to assess the impact on the company are premature. The company will continue to monitor the development of legal requirements in this area.

In the Province of Alberta, regulations governing greenhouse gas emissions from large industrial facilities came into effect July 1, 2007. These regulations cover industrial facilities emitting more than 100,000 tonnes (carbon dioxide equivalent) of greenhouse gas emissions annually and require a reduction by 12 percent in the greenhouse gas emissions per unit of production from each facility s average annual intensity compared with the period 2003 through 2005. Allowed compliance measures include participation in an Alberta emission-trading system or payment (at a rate of $15 per excess tonne of emissions) to Alberta s Climate Change and Emissions Management Fund. Impact on the overall operations of the company has not been material.

The Province of British Columbia introduced a carbon tax in 2008 at an initial rate of $10 per tonne of carbon dioxide and applying to purchases of hydrocarbon fuels and emissions of greenhouse gases. The applicable tax rate was increased to $20 in 2010, and further annual increases of $5 a tonne to a level of $30 a tonne are planned. It is the current policy of the Government of British Columbia to offset revenues from this tax by reductions in corporate and personal income taxes. Impacts on the company and its operations have not been and are not expected to be material.

The Provinces of Ontario and Quebec have passed legislation authorizing the issuing of regulations for the creation of a provincial cap-and-trade system controlling greenhouse gas emissions from industrial facilities. However, details on such possible regulations have not been provided and consequently attempts to assess any impacts on the company are premature.

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The Province of British Columbia has introduced Low Carbon Fuel Standard (LCFS) regulations requiring suppliers of transportation fuels to report the carbon intensity of fuels sold in British Columbia, and beginning in 2011 to reduce the carbon intensity by an increasing amount over a 10-year period. California has introduced similar requirements and some other U.S. states are considering comparable measures. Such measures in California and other U.S. states may have implications for the company s marketing of oil sands production, but the impact cannot be determined at this time. The company s marketing in British Columbia will not be impacted in the early years of the LCFS regulations.

The U.S. Energy Independence and Security Act of 2007 precludes agencies of the U.S. Federal Government from procuring motive fuels from non-conventional petroleum sources that have lifecycle greenhouse gas emissions greater than equivalent conventional fuel. To date, sales of the company s oil sands production have not been affected by this Act.

Further federal or provincial legislation or regulation controlling greenhouse gas emissions could occur and result in increased capital expenditures and operating costs, affect demand and have a material adverse effect on the company s financial condition or results of operations, but any potential impact cannot be estimated at this time.

Other regulatory risk

The company is subject to a wide range of legislation and regulation governing its operations over which it has no control. Changes may affect every aspect of the company s operations and financial performance.

Need to replace reserves

The company s future liquids, bitumen, synthetic oil and natural gas reserves and production, and therefore cash flows, are highly dependent upon the company s success in exploiting its current reserve base and acquiring or discovering additional reserves. Without additions to the company s reserves through exploration, acquisition or development activities, reserves and production will decline over time as reserves are depleted. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient to fund capital expenditures and external sources of capital become limited or unavailable, the company s ability to make the necessary capital investments to maintain and expand oil and natural gas reserves will be impaired. In addition, the company may be unable to find and develop or acquire additional reserves to replace oil and natural gas production at acceptable costs.

Other business risks

Exploring for, producing and transporting petroleum substances involve many risks, which even a combination of experience, knowledge and careful evaluation may not be able to mitigate. These activities are subject to a number of hazards, which may result in fires, explosions, spills, blow-outs or other unexpected or dangerous conditions causing personal injury, property damage, environmental damage and interruption of operations. The company s insurance may not provide adequate coverage in certain unforeseen circumstances.

Uncertainty of reserve estimates

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond the company s control. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flow are based upon a number of factors and assumptions made as of the date on which the reserve estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies and future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable oil and natural gas reserves, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Actual production, revenues, taxes and development, abandonment and operating expenditures with respect to reserves will likely vary from such estimates, and such variances could be material.

Estimates with respect to reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves.

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Project factors

The company s results depend on its ability to develop and operate major projects and facilities as planned. The company s results will, therefore, be affected by events or conditions that affect the advancement, operation, cost or results of such projects or facilities. These risks include the company s ability to obtain the necessary environmental and other regulatory approvals; changes in resources and operating costs including the availability and cost of materials, equipment and qualified personnel; the impact of general economic, business and market conditions; and the occurrence of unforeseen technical difficulties.

Item 1B. Unresolved staff comments

Not applicable.

Item 2. Properties

Reference is made to Item 1 above.

Item 3. Legal proceedings

Not applicable.

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PART II

Item 5. Market for registrant s common equity, related stockholder matters and issuer purchases of equity securities

Market information

The company s common shares trade on the Toronto Stock Exchange and the NYSE Amex LLC, a subsidiary of NYSE Euronext.

Dividends

The following table sets forth the frequency and amount of all cash dividends declared by the company on its outstanding common shares for the two most recent fiscal years:

	2010				2009			
dollars	**Q1**	**Q2**	**Q3**	**Q4**	Q1	Q2	Q3	Q4
Declared dividend per share:	**0.10**	**0.11**	**0.11**	**0.11**	0.10	0.10	0.10	0.10

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 U.S. that owns at least 10 percent of the voting shares of the company.

Imperial is a qualified foreign corporation for purposes of the reduced U.S. capital gains tax rates (15 percent and as low as zero 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.

Reference is made to the Quarterly financial and stock trading data portion of the Financial section on page 81 of this report.

As of February 11, 2011 there were 12,922 holders of record of common shares of the company.

During the period October 1, 2010 to December 31, 2010, the company issued 121,287 common shares to employees or former employees outside the U.S. for $15.50 per share upon the exercise of stock options. During the period October 1, 2010 to December 31, 2010, the company issued 1,065 shares to employees or former employees outside the U.S. under its restricted stock unit plan. These issuances were not registered under the *Securities Act* in reliance on Regulation S thereunder.

On June 23, 2010, the company announced by news release that it had received final approval from the Toronto Stock Exchange for a new normal course issuer bid and will continue its share repurchase program. The new program enables the company to repurchase up to a maximum of about 42.4 million common shares, including common shares purchased for the company s employee savings plan, the company s employee retirement plan and from Exxon Mobil Corporation during the period of June 25, 2010 to June 24, 2011. If not previously terminated, the program will end on June 24, 2011.

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Securities authorized for issuance under equity compensation plans

Sections of the company s management proxy circular are contained in the Proxy information section, starting on page 82. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

Reference is made to the section under the IV. Company executives and executive compensation :

entitled Performance graph within the Compensation discussion and analysis section on page 120 of this report; and

entitled Equity compensation plan information , within the Compensation discussion and analysis section , on page 126 of this report.

Issuer purchases of equity securities

	Total number of shares purchased	Average price paid per share (dollars)	Total number of shares purchased as part of publicly announced plans or programs	Maximum number (or approximate dollar value) of shares that may yet be purchased under the plans or programs
October 2010 (October 1 - October 31)	**-**	**n/a**	**-**	**42,003,431**
November 2010 (November 1 - November 30)	**51,225**	**38.85**	**51,225**	**41,863,465**
December 2010 (December 1 - December 31)	**71,127**	**37.94**	**71,127**	**41,704,795**

Item 6. Selected financial data

millions of dollars	**2010**	2009	2008	2007	2006
Operating revenues	**24,946**	21,292	31,240	25,069	24,505
Net income	**2,210**	1,579	3,878	3,188	3,044
Total assets at year-end	**20,580**	17,473	17,035	16,287	16,141
Long term debt at year-end	**527**	31	34	38	359
Total debt at year-end	**756**	140	143	146	1,437
Other long term obligations at year-end	**2,753**	2,839	2,254	1,914	1,683
dollars					
Net income/share basic	**2.61**	1.86	4.39	3.43	3.12

Net income/share diluted	**2.59**	1.84	4.36	3.41	3.11
Dividends/share	**0.43**	0.40	0.38	0.35	0.32

Reference is made to the table setting forth exchange rates for the Canadian dollar, expressed in U.S. dollars, on page 2 of this report.

Item 7. Management s discussion and analysis of financial condition and results of operations

Reference is made to the section entitled Management s discussion and analysis of financial condition and results of operations in the Financial section, starting on page 35 of this report.

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Item 7A. Quantitative and qualitative disclosures about market risk

Reference is made to the section entitled Market risks and other uncertainties in the Financial section, starting on page 46 of this report. All statements other than historical information incorporated in this Item 7A are forward-looking statements. The actual impact of future market changes could differ materially due to, among other things, factors discussed in this report.

Item 8. Financial statements and supplementary data

Reference is made to the table of contents in the Financial section on page 31 of this report:

Consolidated financial statements, together with the report thereon of PricewaterhouseCoopers LLP (PwC) dated February 25, 2011, beginning with the section entitled Report of independent registered public accounting firm on page 51 and continuing through note 17, Transactions with related parties on page 75;

Supplemental information on oil and gas exploration and production activities (unaudited) starting on page 76; and

Quarterly financial and stock trading data (unaudited) on page 81.

Item 9. Changes in and disagreements with accountants on accounting and financial disclosure

None.

Item 9A. Controls and procedures

As indicated in the certifications in Exhibit 31 of this report, the company s principal executive officer and principal financial officer have evaluated the company s disclosure controls and procedures as of December 31, 2010. Based on that evaluation, these officers have concluded that the company s disclosure controls and procedures are effective in ensuring that information required to be disclosed by the company in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to them in a manner that allows for timely decisions regarding required disclosures and are effective in ensuring that such information is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms.

Reference is made to page 50 of this report for Management s report on internal control over financial reporting and page 51 for the Report of independent registered public accounting firm on the company s internal control over financial reporting as of December 31, 2010.

There has not been any change in the company s internal control over financial reporting during the last fiscal quarter that has materially affected, or is reasonably likely to materially affect, the company s internal control over financial reporting.

Item 9B. Other information

None.

PART III

Item 10. Directors, executive officers and corporate governance

Sections of the company s management proxy circular are contained in the Proxy information section, starting on page 82. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

The company currently has seven directors. The articles of the company require that the board have between five and fifteen directors. Each director is elected to hold office until the close of the next annual meeting. Each of the seven individuals listed in the section entitled Director information on pages 83 to 91 of this report has been nominated for election at the annual meeting of shareholders to be held April 28, 2011. All of the nominees are directors and have been since the dates indicated.

Reference is made to the sections under III. Board of directors :

Director information , on pages 83 to 91 of this report;

The table entitled Audit committee under Board and committee structure , on page 95 of this report; and

Other public company directorships , on page 101 of this report.

Reference is made to the sections under IV. Company executives and executive compensation :

Named executive officers of the company and Other executive officers of the company , on page 107 of this report.

Reference is made to the sections under V. Other important information :

Largest shareholder , on page 129 of this report; and

Ethical business conduct , starting on page 131 of this report.

Item 11. Executive compensation

Sections of the company s management proxy circular are contained in the Proxy information section, starting on page 82. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

Reference is made to the sections under III. Board of directors :

Share ownership guidelines for directors , on page 100 of this report; and

Directors compensation program , on pages 101 to 106 of this report.

Reference is made to the following sections under IV. Company executives and executive compensation :

Report of executive resources committee on executive compensation , on page 108 of this report; and

Compensation discussion and analysis , on pages 108 to 128 of this report.

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Item 12. Security ownership of certain beneficial owners and management and related stockholder matters

Sections of the company s management proxy circular are contained in the Proxy information section, starting on page 82. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

Reference is made to the section under IV. Company executives and executive compensation entitled Equity compensation plan information , within the Compensation discussion and analysis section , on page 126 of this report.

Reference is made to the section under V. Other important information entitled Largest shareholder , on page 129 of this report.

Reference is also made to the security ownership information for directors and executive officers of the company under the preceding Items 10 and 11. As of February 11, 2011, S.M. Smith was the owner of 4,529 common shares of the company and held 151,350 restricted stock units of the company. As of February 11, 2011, B.W. Livingston was the owner of 35,981 common shares of the company and held 122,500 restricted stock units of the company.

The directors and the executive officers of the company, whose compensation for the year-ended December 31, 2010 is described in the sections under III. Board of directors starting on pages 83 and IV. Company executives and executive compensation starting on pages 107, consist of 15 persons, who, as a group, own beneficially 122,733 common shares of the company, being approximately 0.01 percent of the total number of outstanding shares of the company, and 621,766 shares of Exxon Mobil Corporation (including 377,480 restricted shares). This information not being within the knowledge of the company has been provided by the directors and the executive officers individually. As a group, the directors and executive officers of the company held options to acquire 40,500 common shares of the company and held restricted stock units to acquire 456,300 common shares of the company, as of February 11, 2011.

Item 13. Certain relationships and related transactions, and director independence

Sections of the company s management proxy circular are contained in the Proxy information section, starting on page 82. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

Reference is made to the section under V. Other important information entitled Transactions with Exxon Mobil Corporation , on page 129 of this report.

Reference is made to the section under III. Board of directors entitled Independence of the directors , on page 93 of this report.

R.C. Olsen is deemed a non-independent member of the executive resources committee, environmental, health and safety committee, nominations and corporate governance committee and contributions committee under the relevant standards. As an employee of ExxonMobil Production Company, R.C. Olsen is independent of the company s management and is able to assist these committees by reflecting the perspective of the company s shareholders.

Item 14. Principal accountant fees and services

Sections of the company s management proxy circular are contained in the Proxy information section, starting on page 82. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

Reference is made to the section under V. Other important information entitled Auditor information , on page 130 of this report.

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PART IV

Item 15. Exhibits, financial statement schedules

Reference is made to the table of contents in the Financial section on page 31 of this report.

The following exhibits, numbered in accordance with Item 601 of Regulation S-K, are filed as part of this report:

(3) (i) Restated certificate and articles of incorporation of the company (Incorporated herein by reference to Exhibit (3.1) to the company s Form 8-Q filed on May 3, 2006 (File No. 0-12014)).

(ii) By-laws of the company (Incorporated herein by reference to Exhibit (3)(ii) to the company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2003 (File No. 0-12014)).

(4) The company s long-term debt authorized under any instrument does not exceed 10 percent of the company s consolidated assets. The company agrees to furnish to the Commission upon request a copy of any such instrument.

(10) (ii) (1) Alberta Crown Agreement, dated February 4, 1975, relating to the participation of the Province of Alberta in Syncrude (Incorporated herein by reference to Exhibit 13(a) of the company s Registration Statement on Form S-1, as filed with the Securities and Exchange Commission on August 21, 1979 (File No. 2-65290)).

(2) Amendment to Alberta Crown Agreement, dated January 1, 1983 (Incorporated herein by reference to Exhibit (10)(ii)(2) of the company s Annual Report on Form 10-K for the year ended December 31, 1983 (File No. 2-9259)).

(3) Syncrude Ownership and Management Agreement, dated February 4, 1975 (Incorporated herein by reference to Exhibit 13(b) of the company s Registration Statement on Form S-1, as filed with the Securities and Exchange Commission on August 21, 1979 (File No. 2-65290)).

(4) Letter Agreement, dated February 8, 1982, between the Government of Canada and Esso Resources Canada Limited, amending Schedule C to the Syncrude Ownership and Management Agreement filed as Exhibit (10)(ii)(2) (Incorporated herein by reference to Exhibit (20) of the company s Annual Report on Form 10-K for the year ended December 31, 1981 (File No. 2-9259)).

(5) Norman Wells Pipeline Agreement, dated January 1, 1980, relating to the operation, tolls and financing of the pipeline system from the Norman Wells field (Incorporated herein by reference to Exhibit 10(a)(3) of the company s Annual Report on Form 10-K for the year ended December 31, 1981 (File No. 2-9259)).

(6) Norman Wells Pipeline Amending Agreement, dated April 1, 1982 (Incorporated herein by reference to Exhibit (10)(ii)(5) of the company s Annual Report on Form 10-K for the year ended December 31, 1982 (File No. 2-9259)).

(7) Letter Agreement clarifying certain provisions to the Norman Wells Pipeline Agreement, dated August 29, 1983 (Incorporated herein by reference to Exhibit (10)(ii)(7) of the company s Annual Report on Form 10-K for the year ended December 31, 1983 (File No. 2-9259)).

(8) Norman Wells Pipeline Amending Agreement, made as of February 1, 1985, relating to certain amendments ordered by the National Energy Board (Incorporated herein by reference to Exhibit (10)(ii)(8) of the company s Annual Report on Form 10-K for the year ended December 31, 1986 (File No. 0-12014)).

(9) Norman Wells Pipeline Amending Agreement, made as of April 1, 1985, relating to the definition of Operating Year (Incorporated herein by reference to Exhibit (10)(ii)(9) of the company s Annual Report on Form 10-K for the year ended December 31, 1986 (File No. 0-12014)).

(10) Norman Wells Expansion Agreement, dated October 6, 1983, relating to the prices and royalties payable for crude oil production at Norman Wells (Incorporated herein by reference to Exhibit (10)(ii)(8) of the company s Annual Report on Form 10-K for the year ended December 31, 1983 (File No. 2-9259)).

(11) Alberta Cold Lake Crown Agreement, dated June 25, 1984, relating to the royalties payable and the assurances given in respect of the Cold Lake production project (Incorporated herein by reference to Exhibit (10)(ii)(11) of the company s Annual Report on Form 10-K for the year ended December 31, 1986 (File No. 0-12014)).

(12) Amendment to Alberta Crown Agreement, dated January 1, 1986 (Incorporated herein by reference to Exhibit (10)(ii)(12) of the company s Annual Report on Form 10-K for the year ended December 31, 1987 (File No. 0-12014)).

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	(13)	Amendment to Alberta Crown Agreement, dated November 25, 1987 (Incorporated herein by reference to Exhibit (10)(ii)(13) of the company s Annual Report on Form 10-K for the year ended December 31, 1987 (File No. 0-12014)).
	(14)	Amendment to Syncrude Ownership and Management Agreement, dated March 10, 1982 (Incorporated herein by reference to Exhibit (10)(ii)(14) of the company s Annual Report on Form 10-K for the year ended December 31, 1989 (File No. 0-12014)).
	(15)	Amendment to Alberta Crown Agreement, dated August 1, 1991 (Incorporated herein by reference to Exhibit (10)(ii)(15) of the company s Annual Report on Form 10-K for the year ended December 31, 1991 (File No. 0-12014)).
	(16)	Norman Wells Settlement Agreement, dated July 31, 1996. (Incorporated herein by reference to Exhibit (10)(ii)(16) of the company s Annual Report on Form 10-K for the year ended December 31, 1996 (File No. 0-12014)).
	(17)	Amendment to Alberta Crown Agreement, dated January 1, 1997. (Incorporated herein by reference to Exhibit (10)(ii)(17) of the company s Annual Report on Form 10-K for the year ended December 31, 1996 (File No. 0-12014)).
	(18)	Norman Wells Pipeline Amending Agreement, dated December 12, 1997. (Incorporated herein by reference to Exhibit (10)(ii)(18) of the company s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 0-12014)).
	(19)	Norman Wells Pipeline 1999 Amending Agreement, dated May 1, 1999. (Incorporated herein by reference to Exhibit (10)(ii)(19) of the company s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 0-12014)).
	(20)	Alberta Cold Lake Transition Agreement, effective January 1, 2000, relating to the royalties payable in respect of the Cold Lake production project and terminating the Alberta Cold Lake Crown Agreement. (Incorporated herein by reference to Exhibit (10)(ii)(20) of the company s Annual Report on Form 10-K for the year ended December 31, 2001 (File No. 0-12014)).
	(21)	Amendment to Alberta Crown Agreement effective January 1, 2001 (Incorporated herein by reference to Exhibit (10)(ii)(21) of the company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 (File No. 0-12014)).
	(22)	Amendment to Syncrude Ownership and Management Agreement effective January 1, 2001 (Incorporated herein by reference to Exhibit (10)(ii)(22) of the company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 (File No. 0-12014)).
	(23)	Amendment to Syncrude Ownership and Management Agreement effective September 16, 1994 (Incorporated herein by reference to Exhibit (10)(ii)(23) of the company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 (File No. 0-12014)).
	(24)	Amendment to Alberta Crown Agreement dated November 29, 1995 (Incorporated herein by reference to Exhibit (10)(ii)(24) of the company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 (File No. 0-12014)).
	(25)	Syncrude Royalty Amending Agreement, dated November 18, 2008, setting out various items, including the amount of additional royalties that are to be paid to the Province of Alberta in the period from January 1, 2010 to December 31, 2015 in return for certain assurances from the Government of Alberta (Incorporated herein by reference to Exhibit 1.01(10)(ii)(1) of the company s Form 8-K filed on November 19, 2008 (File No. 0-12014)).
	(26)	Syncrude Bitumen Royalty Option Agreement, dated November 18, 2008, setting out the terms of the exercise by the Syncrude Joint Venture owners of the option contained in the existing Crown Agreement to convert to a royalty payable on the value of bitumen, effective January 1, 2009 (Incorporated herein by reference to Exhibit 1.01(10)(ii)(2) of the company s Form 8-K filed on November 19, 2008 (File No. 0-12014)).
	(27)	Project Approval Order No. OSR045 made under the Alberta Mines and Minerals Act and Oil Sands Royalty Regulation, 1997 in respect of the Syncrude Project (Incorporated herein by reference to Exhibit 1.01(10)(ii)(3) of the company s Form 8-K filed on November 19, 2008 (File No. 0-12014)).
(iii)(A)	(1)	Form of Letter relating to Supplemental Retirement Income (Incorporated herein by reference to Exhibit (10)(c)(3) of the company s Annual Report on Form 10-K for the year ended December 31, 1980 (File No. 2-9259)).
	(2)	Incentive Share Unit Plan and Incentive Share Units granted in 2001 are incorporated herein by reference to Exhibit (10)(iii)(A)(2) of the company s Annual Report on Form 10-K for the year -ended December 31, 2001. Units granted in 2000 are incorporated herein by reference to Exhibit (10)(iii)(A)(2) of the company s Annual Report on Form 10-K for the year ended December 31, 2000 (File No. 0-12014); units granted in 1999 are incorporated herein by reference to Exhibit (10)(iii)(A)(3) of the company s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 0-12014); units granted in 1998 are incorporated herein by reference to Exhibit (10)(iii)(A)(3) of the company s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 0-12014).

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(3) Deferred Share Unit Plan. (Incorporated herein by reference to Exhibit(10)(iii)(A)(5) of the company s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 0-12014)).

(4) Deferred Share Unit Plan for Nonemployee Directors. (Incorporated herein by reference to Exhibit (10)(iii)(A)(6) of the company s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 0-12014)).

(5) Form of Earnings Bonus Units (Incorporated herein by reference to Exhibit (10)(iii)(A)(5) of the company s Annual Report on Form 10-K for the year ended December 31, 2003 (File No. 0-12014)) and Earnings Bonus Unit Plan (Incorporated herein by reference to Exhibit (10)(iii)(A)(5) of the company s Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 0-12014)).

(6) Incentive Stock Option Plan and Incentive Stock Options granted in 2002 (Incorporated herein by reference to Exhibit (10)(iii)(A)(6) of the company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 (File No. 0-12014)).

(7) Restricted Stock Unit Plan and Restricted Stock Units granted in 2002 (Incorporated herein by reference to Exhibit (10)(iii)(A)(7) of the company s Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 0-12014)).

(8) Restricted Stock Unit Plan and Restricted Stock Units granted in 2003 (Incorporated herein by reference to Exhibit (10)(iii)(A)(8) of the company s Annual Report on Form 10-K for the year ended December 31, 2003 (File No. 0-12014)).

(9) Restricted Stock Unit Plan and general form for Restricted Stock Units, as amended effective December 31, 2004 (Incorporated herein by reference to Exhibit 99.1 of the company s Form 8-K dated December 31, 2004 (File No. 0-12014)).

(10) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2002, as amended effective August 4, 2006 (Incorporated herein by reference to Exhibit 99.10(III)(A)(1) of the company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 0-12014)).

(11) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2003, as amended effective August 4, 2006 (Incorporated herein by reference to Exhibit 99.10(III)(A)(2) of the company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 0-12014)).

(12) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2004 and 2005, as amended effective August 4, 2006 (Incorporated herein by reference to Exhibit 99.10(III)(A)(3) of the company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 0-12014)).

(13) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2006 and subsequent years, as amended effective August 4, 2006 (Incorporated herein by reference to Exhibit 99.10(III)(A)(4) of the company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 0-12014)).

(14) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2002, as amended effective February 1, 2007 (Incorporated herein by reference to Exhibit 99.1 of the company s Form 8-K filed on February 2, 2007 (File No. 0-12014)).

(15) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2002, as amended effective February 26, 2008 and May 1, 2008 (Incorporated herein by reference to Exhibit 6 [10(iii)(A)(15)] of the company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 (File No. 0-12014)).

(16) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2003, as amended effective February 26, 2008 and May 1, 2008 (Incorporated herein by reference to Exhibit 6 [10(iii)(A)(16)] of the company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 (File No. 0-12014)).

(17) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2004 and 2005, as amended effective February 26, 2008 and May 1, 2008 (Incorporated herein by reference to Exhibit 6 [10(iii)(A)(17)] of the company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 (File No. 0-12014)).

(18) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2006 and 2007, as amended effective February 26, 2008 and May 1, 2008 (Incorporated herein by reference to Exhibit 6 [10(iii)(A)(18)] of the company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 (File No. 0-12014)).

(19) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2008 and subsequent years, as amended effective February 26, 2008 and May 1, 2008 (Incorporated herein by reference to Exhibit 6 [10(iii)(A)(19)] of the company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 (File No. 0-12014)).

(20) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2002, as amended effective November 20, 2008 (Incorporated herein by reference to Exhibit 9.01(c)[10(iii)(A)(1)] of the company s Form 8-K filed on November 25, 2008 (File No. 0-12014)).

(21) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2003, as amended effective November 20, 2008 (Incorporated herein by reference to Exhibit 9.01(c)[10(iii)(A)(2)] of the company s Form 8-K filed on November 25, 2008 (File No. 0-12014)).

(22) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2004 and 2005, as amended effective November 20, 2008 (Incorporated herein by reference to Exhibit 9.01(c)[10(iii)(A)(3)] of the company s Form 8-K filed on November 25, 2008 (File No. 0-12014)).

(23) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2006 and 2007, as amended effective November 20, 2008 (Incorporated herein by reference to Exhibit 9.01(c)[10(iii)(A)(4)] of the company s Form 8-K filed on November 25, 2008 (File No. 0-12014)).

(24) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2008 and subsequent years, as amended effective November 20, 2008 (Incorporated herein by reference to Exhibit 9.01(c)[10(iii)(A)(5)] of the company s Form 8-K filed on November 25, 2008 (File No. 0-12014)).

(25) Amended Deferred Share Unit Plan for selected executives effective November 20, 2008 (Incorporated herein by reference to Exhibit 15(10)(iii)(A)(25) of the company s Form 10-K filed on February 27,2009) (File No. 0-12014)).

(26) Termination of Deferred Share Unit Plan for selected executives effective February 2, 2010 (Reference is made to the company s Form 8-K filed on February 3, 2010 (File No. 0-12014)).

(21) Imperial Oil Resources Limited, McColl-Frontenac Petroleum Inc., Imperial Oil Resources N.W.T. Limited and Imperial Oil Resources Ventures Limited, all incorporated in Canada, are wholly-owned subsidiaries of the company. The names of all other subsidiaries of the company are omitted because, considered in the aggregate as a single subsidiary, they would not constitute a significant subsidiary as of December 31, 2010.

(23) (ii) (A) Consent of Independent Registered Public Accounting Firm (PricewaterhouseCoopers LLP).

(31.1) Certification by principal executive officer of Periodic Financial Report pursuant to Rule 13a-14(a).

(31.2) Certification by principal financial officer of Periodic Financial Report pursuant to Rule 13a-14(a).

(32.1) Certification by chief executive officer of Periodic Financial Report pursuant to Rule 13a-14(b) and 18 U.S.C. Section 1350.

(32.2) Certification by chief financial officer of Periodic Financial Report pursuant to Rule 13a-14(b) and 18 U.S.C. Section 1350.

Copies of Exhibits may be acquired upon written request of any shareholder to the investor relations manager, Imperial Oil Limited, 237 Fourth Avenue S.W., Calgary, Alberta, Canada T2P 3M9, and payment of processing and mailing costs.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf on February 25, 2011 by the undersigned, thereunto duly authorized.

Imperial Oil Limited

By /S/ Bruce H. March
(Bruce H. March, Chairman of the Board,
President and Chief Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 25, 2011 by the following persons on behalf of the registrant and in the capacities indicated.

Signature	Title
/S/ Bruce H. March	Chairman of the Board, President and
(Bruce H. March)	Chief Executive Officer and Director
	(Principal Executive Officer)
/S/ Paul J. Masschelin	Senior Vice-President,
(Paul J. Masschelin)	Finance and Administration, and Treasurer
	(Chief Financial Officer)
/S/ Krystyna T. Hoeg	Director
(Krystyna T. Hoeg)	
/S/ Jack M. Mintz	Director
(Jack M. Mintz)	
/S/ Robert C. Olsen	Director
(Robert C. Olsen)	
/S/ David S. Sutherland	Director
(David S. Sutherland)	
/S/ Sheelagh D. Whittaker	Director
(Sheelagh D. Whittaker)	
/S/ Victor L. Young	Director

(Victor L. Young)

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Financial section

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Financial summary (U.S. GAAP)

millions of dollars	**2010**	2009	2008	2007	2006
Operating revenues	**24,946**	21,292	31,240	25,069	24,505
Net income by segment:					
Upstream	**1,764**	1,324	2,923	2,369	2,376
Downstream	**442**	278	796	921	624
Chemical	**69**	46	100	97	143
Corporate and other	**(65)**	(69)	59	(199)	(99)
Net income	**2,210**	1,579	3,878	3,188	3,044
Cash and cash equivalents at year-end	**267**	513	1,974	1,208	2,158
Total assets at year-end	**20,580**	17,473	17,035	16,287	16,141
Long-term debt at year-end	**527**	31	34	38	359
Total debt at year-end	**756**	140	143	146	1,437
Other long-term obligations at year-end	**2,753**	2,839	2,254	1,914	1,683
Shareholders equity at year-end	**11,177**	9,439	9,065	7,923	7,406
Cash flow from operating activities	**3,207**	1,591	4,263	3,626	3,587
Per-share information (dollars)					
Net income per share basic	**2.61**	1.86	4.39	3.43	3.12
Net income per share diluted	**2.59**	1.84	4.36	3.41	3.11
Dividends	**0.43**	0.40	0.38	0.35	0.32

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Frequently used terms

Listed below are definitions of several of Imperial s key business and 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 in total for the company, it includes total debt and equity. Both of these views include the company s share of amounts applicable to equity companies, which the company believes should be included to provide a more comprehensive measurement of capital employed.

millions of dollars	**2010**	2009	2008
Business uses: asset and liability perspective			
Total assets	**20,580**	17,473	17,035
Less: total current liabilities excluding notes and loans payable	**(4,348)**	(3,659)	(4,084)
total long-term liabilities excluding long-term debt	**(4,299)**	(4,235)	(3,743)
Add: Imperial s share of equity company debt	**33**	36	40
Total capital employed	**11,966**	9,615	9,248
Total company sources: debt and equity perspective			
Notes and loans payable	**229**	109	109
Long-term debt	**527**	31	34
Shareholders equity	**11,177**	9,439	9,065
Add: Imperial s share of equity company debt	**33**	36	40
Total capital employed	**11,966**	9,615	9,248

Return on average capital employed (ROCE)

ROCE is a financial performance ratio. From the perspective of the 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 are more cash flow based, are used to make investment decisions.

millions of dollars	**2010**	2009	2008
Net income	**2,210**	1,579	3,878
Financing costs (after tax), including Imperial s share of equity companies	**2**	2	2
Net income excluding financing costs	**2,212**	1,581	3,880
Average capital employed	**10,791**	9,432	8,684
Return on average capital employed (percent) corporate total	**20.5**	16.8	44.7

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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 reflects the total sources of cash both from operating the company s assets and from the divesting of assets. The company employs a long-standing and regular disciplined review process to ensure that all assets are contributing to the company s strategic 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	**2010**	2009	2008
Cash from operating activities	**3,207**	1,591	4,263
Proceeds from asset sales	**144**	67	272
Total cash flow from operating activities and asset sales	**3,351**	1,658	4,535

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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 business 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 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.

Business environment and risk assessment

Long-term business outlook

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 about 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 of 1.2 percent annually. The vast majority of this increase is expected to occur in developing countries (i.e. those that are not member nations of the Organization for Economic Cooperation and Development).

Oil, gas and coal are expected to remain the predominant energy sources with approximately an 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 2.4 percent per year, and Canadian demand for energy at about 0.4 percent per year. Oil and gas are expected to continue to supply about 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, comprising about 98 percent of the world s transportation energy needs. Primarily because of increased demand in developing countries, global oil consumption is expected to increase by about 20 percent or about 17 million barrels a day by 2030. Canada s oil resources, second only to Saudi Arabia, represent an important potential additional source of supply.

Natural gas is expected to be a major primary energy source globally, capturing about 40 percent of all incremental energy growth and about one-quarter of global energy supplies. Natural gas production from conventional sources in 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 and unconventional resources.

The different forms of renewable energy, including hydro power and biomass in the form of traditional fuels such as firewood, together will supply about 14 percent of the world s energy needs by 2030. This includes modern renewables, such as wind, solar and liquid biofuels which, while expected to see strong demand growth, but because of starting from a relatively small base, are projected to provide only about 3 percent of the world s energy needs by 2030.

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Management s discussion and analysis of financial condition and results of operations (continued)

The information provided in this section includes the company s internal estimates and forecasts based on internal data and analyses as well as publicly available information from external sources including the International Energy Agency.

Upstream

Imperial produces crude oil and natural gas for sale into the North American markets. 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.

Imperial s proven approach of focusing on those elements of the business within its control and taking a long-term view of development allowed the company to continue progressing several key growth projects in an environment of tentative economic recovery following the financial crisis, which impacted the global economy in 2008 and 2009.

Imperial s Upstream business strategies guide the company s exploration, development, production, research and gas marketing activities. These strategies include identifying and pursuing all attractive exploration opportunities, investing in projects that deliver superior returns and maximizing profitability of existing oil and gas production. These strategies are underpinned by a relentless focus on operational excellence, commitment to innovative technologies, development of employees and investment in the communities in which the company operates.

Imperial has a large 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 established producing areas, Imperial s production is expected to come increasingly from unconventional and frontier sources, particularly oil sands, unconventional natural gas and from Canada s North, where Imperial has large undeveloped resource opportunities.

Downstream

Although demand for refined products has improved since 2008 from the lower levels caused by the recent global economic recession, the competitive downstream business environment is expected to continue. Refining margins are largely driven by differences in commodity prices and are a function of 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 these 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, currency fluctuations, 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.

The company will continue to focus on the business elements within its control. Imperial s Downstream strategies are to provide customers with quality service and products at the lowest total cost offer, have the lowest unit costs among industry competitors, ensure efficient and effective use of capital and capitalize on the integration with the company s other businesses.

Imperial owns and operates four refineries in Canada, with aggregate distillation capacity of 502,000 barrels a day and lubricant manufacturing capacity of about 2,900 barrels a day. Imperial s fuels marketing business includes retail operations across Canada serving customers through about 1,850 Esso-branded retail service stations, of which about 510 are company-owned or leased, as well as wholesale and industrial operations through a network of 23 primary distribution terminals, as well as a secondary distribution network.

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Management s discussion and analysis of financial condition and results of operations (continued)

Chemical

The North American petrochemical industry improved in 2010 from the weak levels experienced in the recent economic recession. The company s strategy for its Chemical business is to reduce costs and maximize value by continuing to increase the integration of its chemical plants at Sarnia and Dartmouth with the refineries. The company also benefits from its integration within ExxonMobil s North American chemical businesses, enabling Imperial to maintain a leadership position in its key market segments.

Results of operations

Consolidated

millions of dollars	**2010**	2009	2008
Net income	**2,210**	1,579	3,878

2010

Net income in 2010 was $2,210 million or $2.59 a share on a diluted basis, versus $1,579 million or $1.84 a share for the full year 2009. Earnings increased primarily due to the impacts of higher upstream commodity prices, improved refinery operations and lower refinery maintenance activities, increased Cold Lake bitumen production and Syncrude volumes, and higher Downstream sales volumes and margins. These factors were partially offset by the unfavourable effects of the stronger Canadian dollar and higher royalty costs due to higher commodity prices. Gains from sale of non-operating assets in 2010 were about $40 million higher than the previous year.

2009

Net income in 2009 was $1,579 million or $1.84 a share on a diluted basis, a decrease of $2,299 million or $2.52 a share from 2008. Earnings decreased primarily due to the unfavourable impact of lower crude oil and natural gas commodity prices, which were a result of the global economic downturn. Also impacting 2009 earnings were lower overall downstream margins and product demand. These factors were partially offset by lower royalty costs and the impact of a lower Canadian dollar. Earnings in the full year of 2008 included a gain of $187 million from the sale of Rainbow Pipe Line Co. Ltd.

Upstream

millions of dollars	**2010**	2009	2008
Net income	**1,764**	1,324	2,923

2010

Net income for the year was $1,764 million, up $440 million from 2009. Higher crude oil and natural gas commodity prices in 2010 increased revenues, contributing to higher earnings of about $880 million. Earnings were also positively impacted by higher Cold Lake bitumen production of about $90 million and higher Syncrude volumes, reflecting improved reliability, of about $70 million. These factors were partially offset by the impact of the stronger Canadian dollar of about $320 million and higher royalty costs due to higher commodity prices of about $255 million. Third-party pipeline reliability issues in the second half of 2010 negatively impacted the supply and transportation of western crude oil. The company estimates the negative impact on earnings of about $80 million mostly from lower realizations in the third quarter and October of 2010, the net effect of which has been reflected in the commodity price factor above.

2009

Net income for the year was $1,324 million, down $1,599 million from 2008. Lower crude oil and natural gas commodity prices in 2009 reduced revenues, impacting earnings by about $2,400 million as a result of the global economic downturn. Earnings were also negatively impacted by lower Cold Lake bitumen production of about $100 million and lower conventional volumes from expected reservoir decline of about $60 million. These factors were partially offset by lower royalty costs due to lower commodity prices of about $600 million and the impact of a lower Canadian dollar of about $325 million.

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Management s discussion and analysis of financial condition and results of operations (continued)

Average realizations

Canadian dollars	**2010**	2009	2008
Conventional crude oil realizations (a barrel)	**71.64**	60.32	95.76
Natural gas liquids realizations (a barrel)	**50.09**	41.19	59.35
Natural gas realizations (a thousand cubic feet)	**4.04**	4.11	8.69
Synthetic oil realizations (a barrel)	**80.63**	69.69	106.61
Bitumen realizations (a barrel)	**58.36**	51.81	69.04

2010

The average price of Brent crude, a common benchmark for world oil markets, was U.S. $79.50 a barrel in 2010, up about 29 percent from the previous year. The company s average realizations on sales of Canadian conventional crude oil and synthetic oil from Syncrude production also increased.

The company s average bitumen realizations were higher in 2010, but by less than the relative increase in light crude oil prices, reflecting a widened price spread between the lighter crude oils and Cold Lake bitumen, primarily attributable to third-party pipeline outages.

Canadian natural gas prices in 2010 were unchanged from the previous year. The average of 30-day spot prices for natural gas in Alberta at $4.39 a thousand cubic feet were the same as in 2009. The company s realizations for natural gas averaged $4.04 a thousand cubic feet, down slightly from $4.11 in 2009.

2009

The average price of Brent crude oil was U.S. $61.61 a barrel, down about 36 percent from 2008. The company s realizations on sales of Canadian conventional crude oil and synthetic crude oil from Syncrude production mirrored the same trend as world prices.

Prices for Canadian heavier crude oil also declined along with the lighter crude oil. The company s average realizations for Cold Lake bitumen fell about 25 percent for the full year in 2009, compared to 2008, reflecting the narrowing price spread between light crude oil and Cold Lake bitumen.

Canadian natural gas prices in 2009 were lower than in the previous year. The average of 30-day spot prices for natural gas in Alberta decreased to $4.39 a thousand cubic feet, a decline of about 49 percent from 2008. The company s realizations for natural gas averaged $4.11 a thousand cubic feet, down about 53 percent from 2008.

Crude oil and NGLs - production and sales (a)

thousands of barrels a day	**2010**		2009		2008	
	gross	**net**	gross	net	gross	net
Bitumen	**144**	**115**	141	120	147	124
Synthetic oil	**73**	**67**	70	65	72	62
Conventional crude oil	**23**	**17**	25	20	27	19
Total crude oil production	**240**	**199**	236	205	246	205
NGLs available for sale	**7**	**5**	8	6	10	8
Total crude oil and NGL production	**247**	**204**	244	211	256	213
Cold Lake sales, including diluent (b)	**188**		184		191	
NGL sales	**10**		10		11	

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Management s discussion and analysis of financial condition and results of operations (continued)

Natural gas - production and sales (a)

millions of cubic feet a day	**2010**		2009		2008	
	gross	**net**	gross	net	gross	net
Production (c)	**280**	**254**	295	274	310	249
Sales	**264**		272		288	

(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 Cold Lake bitumen 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.

2010

Gross production of Cold Lake bitumen increased to 144,000 barrels a day in 2010 from 141,000 barrels in 2009. Higher volumes in 2010 were due to improved facility reliability as well as the cyclic nature of production at Cold Lake.

The company s share of gross production from Syncrude averaged 73,000 barrels a day, up from 70,000 barrels in 2009. Increased production was due to improved operational reliability.

2010 gross production of conventional crude oil averaged 23,000 barrels a day, compared with 25,000 barrels in 2009. Planned maintenance activities at the Norman Wells field and natural reservoir decline were the main contributors to the lower production.

Gross production of natural gas in 2010 was 280 million cubic feet a day, down from 295 million cubic feet in 2009. The lower production volume was primarily a result of natural reservoir decline and maintenance activities.

2009

Gross production of bitumen at the company s wholly owned facilities at Cold Lake was 141,000 barrels a day this year, about 6,000 barrels a day lower than 2008. Lower production volumes in 2009 were due to the cyclic nature of production at Cold Lake and well repairs in the northern part of the field. Drilling and steaming activities have since resumed in this area, and production is expected to return to normal levels.

The company s share of Syncrude s gross production of synthetic crude oil was 70,000 barrels a day, a decrease of 2,000 barrels a day from 2008. Planned maintenance activities in the first half of 2009, which included design modifications to improve long-term operational performance, contributed to the reduced production in the year.

Gross production of conventional crude oil decreased to 25,000 barrels a day in 2009, down 2,000 barrels a day from 2008 as a result of natural decline in Western Canadian reservoirs.

Gross production of natural gas was 295 million cubic feet a day, down from 310 million cubic feet in 2008. The lower production volume was primarily a result of natural reservoir decline.

Downstream

millions of dollars	**2010**	2009	2008
Net income	**442**	278	796

2010

Net income was $442 million, an increase of $164 million over 2009. Higher earnings were primarily due to favourable impacts of about $145 million associated with improved refinery operations and lower refinery maintenance activities, improved sales volumes of about $35 million and an additional contribution from sale of non-operating assets of about $35 million. Stronger overall margins also contributed about $30 million to the earnings increase, despite a negative impact from alternate sourcing of crude oil as a result of third-party pipeline outages. These factors were partially offset by the unfavourable effects of the stronger Canadian dollar of about $90 million.

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Management s discussion and analysis of financial condition and results of operations (continued)

2009

Net income was $278 million in 2009, $518 million lower than 2008. Earnings in 2008 included a gain of $187 million from the sale of Rainbow Pipe Line Co. Ltd. Also impacting earnings in 2009 were lower overall margins of about $270 million and lower sales volumes of about $70 million due to the slowdown in the economy. These factors were partially offset by the favourable impact of a weaker Canadian dollar of about $40 million.

Refinery utilization

thousands of barrels a day (a)	**2010**	2009	2008
Total refinery throughput (b)	**444**	413	446
Refinery capacity at December 31	**502**	502	502
Utilization of total refinery capacity (percent)	**88**	82	89

Sales

thousands of barrels a day (a)	**2010**	2009	2008
Gasolines	**218**	200	204
Heating, diesel and jet fuels	**153**	143	157
Heavy fuel oils	**28**	27	30
Lube oils and other products	**43**	39	47
Net petroleum product sales	**442**	409	438

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

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

2010

Total refinery throughput was 444,000 barrels a day, up from 2009, and average refinery capacity utilization increased to 88 percent from the previous year s 82 percent. Improved reliability and lower maintenance activities as well as improved market conditions helped to increase volumes and utilization. Total net petroleum sales also increased and were up to 442,000 barrels a day, compared to the low levels of 409,000 barrels in 2009.

2009

Total refinery throughput was 413,000 barrels a day, down from 2008, and average refinery capacity utilization was 82 percent. Production gains from operating and reliability improvements through the year were offset by the impact of declining economic conditions that did not support running the refineries to full capacity, and also resulted in lower net petroleum product sales of 409,000 barrels a day.

Chemical

millions of dollars	**2010**	2009	2008
Net income	**69**	46	100

Sales

thousands of tonnes	**2010**	2009	2008
Polymers and basic chemicals	**711**	765	760
Intermediate and others	**278**	261	261
Total petrochemical sales	**989**	1,026	1,021

2010

Net income was $69 million, up $23 million from 2009. Improved industry margins were partially offset by lower sales volumes for polyethylene products and higher costs due to planned maintenance activities.

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Management s discussion and analysis of financial condition and results of operations (continued)

2009

Net income was $46 million, $54 million lower than 2008. Earnings were negatively impacted by lower overall margins as a result of the slow economy. Sales volumes of chemical products continued to be impacted by weak industry demand.

Corporate and other

millions of dollars	**2010**	2009	2008
Net income	**(65)**	(69)	59

2010

Net income effects were negative $65 million, in line with the negative $69 million reported last year.

2009

Net income effects were negative $69 million, versus $59 million in 2008. Unfavourable effects in 2009 were primarily due to changes in share-based compensation charges and lower interest income from lower yields on cash balances.

Liquidity and capital resources

Sources and uses of cash

millions of dollars	**2010**	2009	2008
Cash provided by/(used in)			
Operating activities	**3,207**	1,591	4,263
Investing activities	**(3,709)**	(2,216)	(961)
Financing activities	**256**	(836)	(2,536)
Increase/(decrease) in cash and cash equivalents	**(246)**	(1,461)	766
Cash and cash equivalents at end of year	**267**	513	1,974

Although the company issues long-term debt from time to time and maintains a revolving commercial paper program, internally generated funds largely 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 to ensure that it is secure and readily available to meet the company s cash requirements, while optimizing returns on cash balances.

Cash flows from operating activities are highly dependent on crude oil and natural gas prices, as well as petroleum and chemical product margins. In addition, to support cash flows in future periods, the company needs to continually find and develop new resources, and continue to develop and apply new technologies to existing fields, in order to maintain or increase production. 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 portfolio of development opportunities and the complementary nature of its business segments help mitigate the overall risks for the company and its cash flows. Further, due to its financial strength, debt capacity and 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.

An independent actuarial valuation of the company s registered retirement benefit plans was completed as at December 31, 2009. As a result of the valuation, the company contributed $421 million to the registered retirement benefit plans in 2010. The next required independent actuarial valuation will be as at December 31, 2010 and the company will continue to contribute within the requirements of pension regulations. Future funding requirements are not expected to affect the company s existing capital investment plans or its ability to pursue new investment opportunities.

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Management s discussion and analysis of financial condition and results of operations (continued)

Cash flow from operating activities

2010

Cash flow generated from operating activities was $3,207 million, an increase of $1,616 million from the full year 2009. Higher cash flow was primarily due to higher earnings and working capital effects, partially offset by higher 2010 funding contributions to the company s registered pension plans.

2009

Cash provided by operating activities was $1,591 million, a decrease of $2,672 million from 2008. Lower cash flow was primarily due to lower net income and timing of scheduled income tax payments.

Cash flow from investing activities

2010

Investing activities used net cash of $3,709 million in 2010, compared to $2,216 million in 2009. Additions to property, plant and equipment were $3,856 million, compared with $2,285 million last year. Proceeds from asset sales were $144 million compared with $67 million in 2009.

2009

Investing activities used net cash of $2,216 million in 2009, an increase of $1,255 million from 2008. Additions to property, plant and equipment were $2,285 million, compared with $1,231 million last year. Proceeds from asset sales were $67 million in 2009, compared with $272 million in 2008. The 2008 results included proceeds from the sale of the Rainbow pipeline.

Cash flow from financing activities

2010

Cash from financing activities was $256 million, compared with cash used in financing activities of $836 million in 2009.

The company raised new debt of $620 million by drawing on existing facilities. At the end of 2010, total debt outstanding was $756 million, compared with $140 million at the end of 2009.

During 2010, the company did not make any share repurchases except those to offset the dilutive effects from the exercise of share-based awards. The company will continue to evaluate its share repurchase program in the context of its overall capital project activities.

Cash dividends of $356 million were paid in 2010 compared with dividends of $341 million in 2009. Per-share dividends paid in 2010 totaled $0.42, up from $0.40 in 2009.

In the third quarter, to support the commercial paper program, the company entered into an unsecured committed bank credit facility in the amount of $200 million that matures in July 2012. The company has not drawn on this facility.

2009

Cash used in financing activities was $836 million in 2009, $1,700 million lower than in 2008.

During 2009, share repurchases were reduced to about 12 million shares for $492 million, including shares purchased from ExxonMobil, compared to about 44 million shares purchased in 2008 for $2,210 million. Imperial did not make any significant share repurchases after the second quarter of 2009, as cash flow from operations was used to fund growth projects such as Kearl. The company will continue to evaluate its share-purchase program in the context of its overall capital activities.

In the third quarter, the company entered into a floating rate loan agreement with an affiliated company of Exxon Mobil Corporation that provides for borrowings of up to $5 billion (Canadian) at interest equivalent to Canadian market rates. This facility will enable Imperial to efficiently access funds as necessary in the future. The company has not drawn on this agreement.

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Management s discussion and analysis of financial condition and results of operations (continued)

The company paid dividends totaling 40 cents a share in 2009, up from 37 cents in 2008.

Total debt outstanding at the end of 2009, excluding the company s share of equity company debt, was $140 million, compared with $143 million at the end of 2008.

Financial percentages and ratios

	2010	2009	2008
Total debt as a percentage of capital (a)	**7**	2	2
Interest coverage ratio earnings basis (b)	**370**	276	481

(a) Current and long-term debt (page 53) and the company s share of equity company debt, divided by debt and shareholders equity (page 53).

(b) Net income (page 52), debt-related interest before capitalization, including the company s share of equity company interest, and income taxes (page 52), divided by debt-related interest before capitalization, including the company s share of equity company interest.

Debt represented seven percent of the company s capital structure at the end of 2010, a five percent increase from the end of 2009.

Debt-related interest incurred in 2010, before capitalization of interest, was $6 million, compared with $5 million in 2009. The average effective interest rate on the company s debt was 1.3 percent in 2010, compared with 3.3 percent in 2009.

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.

The company does not use any derivative instruments to offset exposures associated with hydrocarbon prices, currency exchange rates and interest rates that arise from existing assets, liabilities and transactions. The company does not engage in speculative derivative activities nor does it use derivatives with leveraged features.

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Management s discussion and analysis of financial condition and results of operations (continued)

Commitments

The following table shows the company s commitments outstanding at December 31, 2010. It combines data 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 2011	2012 to 2015	2016 and beyond	Total amount
Long-term debt (a)	Note 15	-	514	13	527
- Due in one year		4	-	-	4
Operating leases (b)	Note 14	61	170	39	270
Unconditional purchase obligations (c)	Note 10	66	134	173	373
Firm capital commitments (d)		1,689	202	100	1,991
Pension and other post-retirement obligations (e)	Note 5	398	204	1,085	1,687
Asset retirement obligations (f)	Note 6	89	392	292	773
Other long-term purchase agreements (g)		94	554	1,391	2,039

(a) Long-term debt includes a long-term loan from an affiliated company of Exxon Mobil Corporation of $500 million and capital lease obligations of $31 million, $4 million of which is due in one year. The payment by period for the related party long-term loan is estimated based on the right of the related party to cancel the loan on at least 370 days advance written notice.
(b) Minimum commitments for operating leases, shown on an undiscounted basis, primarily cover office buildings, rail cars and service stations.
(c) Unconditional purchase obligations are those long-term commitments that are non-cancelable or cancellable only under certain conditions and that third parties have used to secure financing for the facilities that will provide the contracted goods and services. They mainly pertain to pipeline throughput agreements.
(d) Firm capital commitments related to capital projects, shown on an undiscounted basis. The largest commitments outstanding at year-end 2010 were $1,401 million associated with the company s share of the Kearl project.
(e) The amount by which the 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 2011 and estimated benefit payments for unfunded plans in all years.
(f) Asset retirement obligations represent the fair value of legal obligations associated with site restoration on the retirement of assets with determinable useful lives.
(g) Other long-term purchase agreements are non-cancelable, long-term commitments other than unconditional purchase obligations. They include primarily raw material supply and transportation services agreements.

Unrecognized tax benefits totaling $147 million have not been included in the company s commitments table because the company does not expect there will be any cash impact from the final settlements as sufficient funds have been deposited with the Canada Revenue Agency. Further details on the unrecognized tax benefits can be found in note 4 to the financial statements on page 61.

Litigation and other contingencies

As discussed in note 10 to the consolidated financial statements on page 71, a variety of claims have been made 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, financial condition, or financial statements taken as a whole. There are no events or uncertainties beyond those already included in reported financial information that would indicate a material change in future operating results or financial condition.

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Management s discussion and analysis of financial condition and results of operations (continued)

Capital and exploration expenditures

millions of dollars	**2010**	2009
Upstream (a)	**3,844**	2,167
Downstream	**184**	251
Chemical	**10**	15
Other	**7**	5
Total	**4,045**	2,438

(a) Exploration expenses included.

Total capital and exploration expenditures were $4,045 million in 2010, an increase of $1,607 million from 2009.

The funds were used mainly to advance the Kearl oil sands project, maintain Cold Lake production capacity, advance other major Upstream projects and invest in environmental performance initiatives.

For the Upstream segment, capital expenditures were $3,844 million, compared with $2,167 million in 2009.

Expenditures were primarily directed towards the advancement of the Kearl oil sands project. At the end of 2010, the initial development of the Kearl project was more than 50 percent complete with expected start up in late 2012. All plant pilings were completed, substantial concrete foundations were laid and detailed engineering was essentially complete. The company is currently reconfiguring the Kearl project development plan to include a combination of debottlenecking and expansion to minimize facility requirements and to reduce the plant footprint.

Other Upstream investments included development drilling at Cold Lake, exploration drilling at Horn River as well as environmental projects at Syncrude.

Planned capital and exploration expenditures in the Upstream segment are about $3.8 to $4.3 billion for 2011. Investments are mainly planned for the Kearl oil sands project. Other investments will include environmental and other projects at Syncrude, development drilling at Cold Lake and advancing the Nabiye project, the next phase of expansion at Cold Lake.

For the Downstream segment, capital expenditures were $184 million in 2010, compared with $251 million in 2009. In 2010, Downstream capital expenditures focused mainly on refinery projects to improve reliability, feedstock flexibility, energy efficiency and environmental performance, as well as continued upgrades to the retail network.

Planned capital expenditures for the Downstream segment in 2011 are about $175 million focused on improving refinery reliability and environmental and safety performance, as well as continuing upgrades to the retail network, including new point-of-sale technology.

Of the capital expenditures for the Chemical segment in 2010, the major investment was directed to increasing feedstock flexibility and reliability improvements.

Planned capital expenditures for Chemical in 2011 are about $10 million and will include investments in safety initiatives, water management system enhancements and reliability improvements.

Total capital and exploration expenditures for the company in 2011 are expected to be between $4.0 and 4.5 billion and the company is looking to invest about $35 to $40 billion in growth projects over the next decade. Actual spending could vary depending on the progress of individual projects.

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Management s discussion and analysis of financial condition and results of operations (continued)

Market risks and other uncertainties

Crude oil, natural gas, petroleum product and chemical prices have fluctuated in response to changing market forces. The impacts of these price fluctuations on earnings from Upstream, Downstream and Chemical operations have varied. In addition, industry crude oil and natural gas commodity prices and petroleum and chemical product prices are commonly benchmarked in U.S. dollars. The majority of Imperial s sales and purchases are related to these industry U.S. dollar benchmarks. As the company records and reports its financial results in Canadian dollars, to the extent that the Canadian/U.S. dollar exchange rate fluctuates, the company s earnings will be affected. The company s potential exposure to commodity price and margin and Canadian/U.S. dollar exchange rate fluctuations is summarized in the earnings sensitivities table below, which shows the estimated annual effect, under current conditions, of the company s after-tax net income.

Earnings sensitivities (a)

millions of dollars after tax		
Nine dollars (U.S.) a barrel change in crude oil prices	+ (-)	330
Forty cents a thousand cubic feet change in natural gas prices	+ (-)	3
One dollar (U.S.) a barrel change in sales margins for total petroleum products	+ (-)	125
One cent (U.S.) a pound change in sales margins for polyethylene	+ (-)	6
One-quarter percent decrease (increase) in short-term interest rates	+ (-)	1
Ten cents decrease (increase) in the value of the Canadian dollar versus the U.S. dollar	+ (-)	480

(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 2010. 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 increased from year-end 2009 by about $8 million (after tax) a year for each one-cent change, primarily due to the increase in crude oil commodity prices.

The global energy markets can give rise to extended periods in which market conditions are adverse to one or more of the company s businesses. Such conditions, along with the capital-intensive nature of the industry and very long lead times associated with many of our projects, underscore the importance of maintaining a strong financial position. Management views the company s financial strength as a competitive advantage.

In general, segment results are not dependent on the ability to sell and/or purchase products to/from other segments. Instead, where such sales take place, they are the result of efficiencies and competitive advantages of integrated refinery/chemical complexes. Additionally, intersegment sales are at market-based prices. The products bought and sold between segments can also be acquired in worldwide markets that have substantial liquidity, capacity and transportation capabilities. About 60 percent of the company s intersegment sales are crude oil produced by the Upstream and sold to the Downstream. Other intersegment sales include those between refineries and chemical plants related to raw materials, feedstocks and finished products.

Although price levels of crude oil and natural gas may rise or fall significantly over the short to medium term, industry economics over the long term will continue to be driven by market supply and demand. Accordingly, the company tests the viability of all of its investments over a broad range of future prices. The company s assessment is that its operations will continue to be successful in a variety of market conditions. This is the outcome of disciplined investment and asset management programs. Investment opportunities are tested against a variety of market conditions, including low-price scenarios.

The company has an active asset management program in which underperforming assets are either improved to acceptable levels or considered for divestment. The asset management program includes a disciplined, regular review to ensure that all assets are contributing to the company s strategic objectives. The result is an efficient capital base, and the company has seldom had to write down the carrying value of assets, even during periods of low commodity prices.

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Management s discussion and analysis of financial condition and results of operations (continued)

Risk management

The company s size, strong capital structure and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the company s enterprise-wide risk from changes in commodity prices and currency rates. The company s financial strength and debt capacity give it the opportunity to advance business plans in the pursuit of maximizing shareholder value in the full range of market conditions. Also, the company progresses large capital projects in a phased manner so that adjustments can be made when significant changes in market conditions occur. As a result, the company does not make use of derivative instruments to mitigate the impact of such changes. The company does not engage in speculative derivative activities or derivative trading activities nor does it use derivatives with leveraged features. The company maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity.

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 56.

Oil and gas reserves

Evaluations of oil and gas reserves are important to the effective management of upstream assets. They are integral to making investment decisions about oil and gas properties such as whether development should proceed.

Oil and gas reserve quantities are also used as the basis for calculating unit-of-production depreciation rates and for evaluating impairment. Proved oil and gas reserve estimates are based on geological and engineering data, which have demonstrated with reasonable certainty that these reserves are economically producible in future years from known reservoirs under existing economic and operating conditions, operating methods and government regulations.

The estimation of proved reserves is controlled by the company through long-standing approval guidelines. Reserve changes are made within a well-established, disciplined process driven by senior-level geoscience and engineering professionals, 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 a rigorous peer review, technical evaluations, analysis of well and field performance information and a requirement that management make significant funding commitments toward the development of the reserves prior to reporting as proved.

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, regulatory approvals and significant changes in long-term oil and gas price levels.

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 prices and costs that are used in the estimation of reserves. This category can also include 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 using the unit-of-production method. 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.

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Management s discussion and analysis of financial condition and results of operations (continued)

Impact of reserves on depreciation

The calculation of unit-of-production depreciation is a critical accounting estimate that measures the depreciation of upstream 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 reserve estimates used for internal planning and capital investment decisions. 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. Significant unproved properties are assessed for impairment individually and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time that the company expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period.

The company performs asset valuation analyses on an ongoing basis as a part of its asset management program. These analyses monitor the performance of assets against corporate objectives. They also assist the company in assessing whether the carrying amounts of any of its assets may not be recoverable. In addition to estimating oil and gas reserve volumes in conducting these analyses, it is also necessary to estimate future oil and gas prices. Trigger events for impairment evaluations 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 forecast operating losses.

In general, the company does not view temporarily low oil 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, the relative growth/decline in supply versus demand will determine industry prices over the long term, and these cannot be accurately predicted. 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 crude oil and natural gas markets, petroleum products and chemicals. These are the same price assumptions that are used for capital investment decisions. Volumes are based on individual field production profiles, which are also updated annually.

Supplemental information regarding oil and gas results of operations, capitalized costs and reserves is provided following the notes to the consolidated financial statements. Future prices used for any impairment tests will vary from the one used in the supplemental oil and gas disclosure and could be lower or higher for any given year.

Suspended exploratory well costs

The company carries exploratory well costs as an asset when the well has found a sufficient quantity of reserves to justify its completion as a producing well and where 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 are charged to expense. Assessing whether a project has made sufficient progress is a subjective area and requires careful consideration of the relevant facts and circumstances. The facts and circumstances that support continued capitalization of suspended wells as of year-end 2010 are disclosed in note 16 to the consolidated financial statements.

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Management s discussion and analysis of financial condition and results of operations (continued)

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 7.00 percent used in 2010 compares to actual returns of 5.5 percent and 8.8 percent achieved over the last 10- and 20-year periods ending December 31, 2010. 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 5 to the consolidated financial statements on page 62. At Imperial, differences between actual returns on plan assets and the long-term expected returns are not recorded in pension expense in the year the differences occur. Such differences are deferred, along with other actuarial gains and losses, and are amortized into pension expense over the expected remaining service life of employees. Employee benefit expense represented less than two percent of total expenses in 2010.

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 production and manufacturing expenses. 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 2010, the obligations were discounted at six percent and the accretion expense was $48 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.

Tax contingencies

The operations of the company are complex, and related tax interpretations, regulations and legislation are continually changing. Significant management judgment is required in the accounting for income tax contingencies and tax disputes because the outcomes are often difficult to predict.

GAAP requires recognition and measurement of uncertain tax positions that the company has taken or expects to take in its income tax returns. The benefit of an uncertain tax position can only be recognized in the financial statements if management concludes that it is more likely than not that the position will be sustained with the tax authorities. For a position that is likely to be sustained, the benefit recognized in the financial statements is measured at the largest amount that is greater than 50 percent likely of being realized. A reserve is established for the difference between a position taken in an income tax return and the amount recognized in the financial statements. The company s unrecognized tax benefits and a description of open tax years are summarized in note 4 to the consolidated financial statements on page 61.

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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 criteria established in *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, 2010.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the company s internal control over financial reporting as of December 31, 2010, as stated in their report which is included herein.

/S/ Bruce H. March

B.H. March

Chairman, president and

chief executive officer

/S/ Paul J. Masschelin

P.J. Masschelin

Senior vice-president,

finance and administration, and treasurer

(Principal accounting officer and principal financial officer)

February 25, 2011

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Report of independent registered public accounting firm

To the Shareholders of Imperial Oil Limited

We have audited the accompanying consolidated balance sheet of Imperial Oil Limited as of December 31, 2010 and December 31, 2009, and the related consolidated statements of income, shareholders equity and cash flows for each of the years in the three-year period ended December 31, 2010. We also have audited Imperial Oil Limited s internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying management s report on internal control over financial reporting. Our responsibility is to express an opinion on these consolidated financial statements and an opinion on the company s internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included 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 statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide 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 consolidated financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Imperial Oil Limited as of December 31, 2010 and December 31, 2009, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, Imperial Oil Limited maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

/S/ PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta, Canada

February 25, 2011

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Consolidated statement of income (U.S. GAAP)

millions of Canadian dollars

For the years ended December 31	**2010**	2009	2008
Revenues and other income			
Operating revenues (a)(b)	**24,946**	21,292	31,240
Investment and other income (note 9)	**146**	106	339
Total revenues and other income	**25,092**	21,398	31,579
Expenses			
Exploration	**191**	153	132
Purchases of crude oil and products (c)	**14,811**	11,934	18,865
Production and manufacturing (d)	**3,996**	3,951	4,228
Selling and general	**1,070**	1,106	1,038
Federal excise tax (a)	**1,316**	1,268	1,312
Depreciation and depletion	**747**	781	728
Financing costs (note 13)	**7**	5	-
Total expenses	**22,138**	19,198	26,303
Income before income taxes	**2,954**	2,200	5,276
Income taxes (note 4)	**744**	621	1,398
Net income	**2,210**	1,579	3,878
Per-share information (Canadian dollars)			
Net income per common share - basic (note 11)	**2.61**	1.86	4.39
Net income per common share - diluted (note 11)	**2.59**	1.84	4.36
Dividends	**0.43**	0.40	0.38

(a) Operating revenues include federal excise tax of $1,316 million (2009 - $1,268 million, 2008 - $1,312 million).
(b) Operating revenues include amounts from related parties of $2,250 million (2009 - $1,699 million, 2008 - $2,150 million), (note 17).
(c) Purchases of crude oil and products include amounts from related parties of $2,828 million (2009 - $3,111 million, 2008 - $4,729 million), (note 17).
(d) Production and manufacturing expenses include amounts to related parties of $233 million (2009 - $217 million, 2008 - $169 million), (note 17).
The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

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Consolidated balance sheet (U.S. GAAP)

millions of Canadian dollars

At December 31	2010	2009
Assets		
Current Assets		
Cash	**267**	513
Accounts receivable, less estimated doubtful amounts	**2,000**	1,714
Inventories of crude oil and products (note 12)	**527**	564
Materials, supplies and prepaid expenses	**246**	247
Deferred income tax assets (note 4)	**498**	467
Total current assets	**3,538**	3,505
Long-term receivables, investments and other long-term assets	**870**	854
Property, plant and equipment, less accumulated depreciation and depletion (note 3)	**15,905**	12,852
Goodwill (note 3)	**204**	204
Other intangible assets, net	**63**	58
Total assets (note 3)	**20,580**	17,473
Liabilities		
Current liabilities		
Notes and loans payable	**229**	109
Accounts payable and accrued liabilities (a)	**3,470**	2,811
Income taxes payable	**878**	848
Total current liabilities	**4,577**	3,768
Long-term debt (b)(note 15)	**527**	31
Other long-term obligations (note 6)	**2,753**	2,839
Deferred income tax liabilities (note 4)	**1,546**	1,396
Total liabilities	**9,403**	8,034
Commitments and contingent liabilities (note 10)		
Shareholders equity		
Common shares at stated value (c)(note 11)	**1,511**	1,508
Earnings reinvested	**11,090**	9,252
Accumulated other comprehensive income	**(1,424)**	(1,321)
Total shareholders equity	**11,177**	9,439
Total liabilities and shareholders equity	**20,580**	17,473

(a) Accounts payable and accrued liabilities include amounts to related parties of $455 million (2009 - $59 million), (note 17).
(b) Long-term debt includes amounts to related parties of $500 million (2009 nil).
(c) Number of common shares outstanding was 848 million (2009 - 848 million), (note 11).
The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

Approved by the directors

/s/ B.H. March	/s/ Paul J. Masschelin
B.H. March	P.J. Masschelin
Chairman, president and	Senior vice-president,
chief executive officer	finance and administration, and treasurer

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Consolidated statement of shareholders equity (U.S. GAAP)

millions of Canadian dollars

At December 31	**2010**	2009	2008
Common shares at stated value (note 11)			
At beginning of year	**1,508**	1,528	1,600
Issued under the stock option plan	**3**	1	7
Share purchases at stated value	**-**	(21)	(79)
At end of year	**1,511**	1,508	1,528
Earnings reinvested			
At beginning of year	**9,252**	8,484	7,071
Net income for the year	**2,210**	1,579	3,878
Share purchases in excess of stated value	**(8)**	(471)	(2,131)
Dividends	**(364)**	(340)	(334)
At end of year	**11,090**	9,252	8,484
Accumulated other comprehensive income			
At beginning of year	**(1,321)**	(947)	(748)
Post-retirement benefits liability adjustment (note 5)	**(217)**	(468)	(283)
Amortization of post-retirement benefits liability adjustment included in net periodic benefit cost	**114**	94	84
At end of year	**(1,424)**	(1,321)	(947)
Shareholders equity at end of year	**11,177**	9,439	9,065
Comprehensive income for the year			
Net income for the year	**2,210**	1,579	3,878
Other comprehensive income			
Post-retirement benefits liability adjustment	**(103)**	(374)	(199)
Total comprehensive income for the year	**2,107**	1,205	3,679

The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

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Consolidated statement of cash flows (U.S. GAAP)

millions of Canadian dollars

Inflow/(outflow)

For the years ended December 31	**2010**	2009	2008
Operating activities			
Net income	**2,210**	1,579	3,878
Adjustments for non-cash items:			
Depreciation and depletion	**747**	781	728
(Gain)/loss on asset sales	**(95)**	(45)	(241)
Deferred income taxes and other	**152**	(61)	387
Changes in operating assets and liabilities:			
Accounts receivable	**(289)**	(261)	679
Inventories and prepaids	**38**	42	(159)
Income taxes payable	**30**	(650)	-
Accounts payable	**651**	271	(798)
All other items - net (a)	**(237)**	(65)	(211)
Cash from (used in) operating activities	**3,207**	1,591	4,263
Investing activities			
Additions to property, plant and equipment and intangibles	**(3,856)**	(2,285)	(1,231)
Proceeds from asset sales	**144**	67	272
Loans to equity company	**3**	2	(2)
Cash from (used in) investing activities	**(3,709)**	(2,216)	(961)
Financing activities			
Short-term debt - net	**120**	-	-
Long-term debt issued	**500**	-	-
Reduction in capitalized lease obligations	**(3)**	(4)	(3)
Issuance of common shares under stock option plan	**3**	1	7
Common shares purchased (note 11)	**(8)**	(492)	(2,210)
Dividends paid	**(356)**	(341)	(330)
Cash from (used in) financing activities	**256**	(836)	(2,536)
Increase (decrease) in cash	**(246)**	(1,461)	766
Cash at beginning of year	**513**	1,974	1,208
Cash at end of year (b)	**267**	513	1,974

(a) Includes contribution to registered pension plans of $421 million (2009 - $180 million, 2008 - $165 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 in the Notes to Consolidated Financial Statements is an integral part of these statements.

Notes to consolidated financial statements

The accompanying consolidated financial statements and the supporting and supplemental material are the responsibility of the management of Imperial Oil Limited.

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 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 2010 presentation. All amounts are in Canadian dollars unless otherwise indicated.

1. Summary of significant accounting policies

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 Upstream activities 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 as well as its 70.96 percent interest in the Kearl project, which is currently under development.

Inventories

Inventories are recorded at the lower of cost or current market 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. Costs of productive wells and development dry holes are capitalized and amortized using the unit-of-production method. 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 are charged to expense.

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Notes to consolidated financial statements (continued)

Acquisition costs of proved properties are amortized using a unit-of-production method, computed on the basis of total proved oil and gas reserves. Unproved properties are assessed for impairment individually and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time the company expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period. The valuation allowances are reviewed at least annually. Other exploratory expenditures, including geophysical costs and other dry hole costs, are expensed as incurred.

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. 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 and natural gas commodity prices and foreign-currency exchange rates. Annual volumes are based on individual field production profiles, which are also updated annually.

In general, impairment analyses are based on reserve estimates used for internal planning and capital investment decisions. 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.

Based on definitions under the U.S. Securities and Exchange Commission s Rule 4-10(a) of Regulation S-X, activities involving oil and gas resources extracted by mining methods are permitted to be reported as oil and gas producing activities. Accounting policies for the company s activities involving oil and gas resources extracted by mining methods are the same as those described in this summary of significant accounting policies for the company s oil and gas producing activities. As a result, previous descriptions of accounting policies for the company s activities involving oil and gas resources extracted by mining methods become duplicative and are therefore removed from this summary.

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

Notes to consolidated financial statements (continued)

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.

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 reclamation and remediation and costs of abandonment and demolition of oil and gas wells and related facilities. The company uses estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation, technical assessments of the assets, estimated amounts and timing of settlements, the credit-adjusted risk-free rate to be used, and inflation rates. 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. 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. These liabilities are not discounted.

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.

Fair value

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. Hierarchy Levels 1, 2 or 3 are terms for the priority of inputs to valuation techniques used to measure fair value. Hierarchy Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Hierarchy Level 2 inputs are inputs other than quoted prices included within Level 1 that are directly or indirectly observable for the asset or liability. Hierarchy Level 3 inputs are inputs that are not observable in the market.

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.

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Notes to consolidated financial statements (continued)

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.

Purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another are combined and recorded as exchanges measured at the book value of the item sold.

Share-based compensation

The company awards share-based compensation to certain employees in the form of restricted stock units. Compensation expense is measured each reporting period based on the company s current stock price and is recorded as selling and general expenses in the consolidated statement of income over the requisite service period of each award. See note 8 to the consolidated financial statements on page 68 for further details.

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, the federal goods and services tax and the federal/provincial harmonized sales tax.

2. Accounting change for variable interest entities

Effective January 1, 2010, the company adopted the authoritative guidance for variable-interest entities (VIEs). The guidance requires the enterprise to qualitatively assess if it is the primary beneficiary of the VIE and, if so, the VIE must be consolidated. The adoption did not have any impact on the company s consolidated financial statements.

3. Business segments

The company operates its business in Canada. The Upstream, Downstream and Chemical 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 Upstream segment is organized and operates to explore for and ultimately produce crude oil and its equivalent, and natural gas. The Downstream segment is organized and operates to refine crude oil into petroleum products and the distribution and marketing of these products. The Chemical 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, capitalized interest costs, short-term borrowings, long-term debt and liabilities associated with incentive compensation and post-retirement benefits liability adjustment. Net income in this segment primarily includes financing costs, interest income and share-based incentive compensation expenses.

Segment accounting policies are the same as those described in the summary of significant accounting policies. Upstream, Downstream and Chemical 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.

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Notes to consolidated financial statements (continued)

	Upstream			Downstream			Chemical		
millions of dollars	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Revenues and other income									
Operating revenues (a)	**4,283**	3,552	5,819	**19,565**	16,793	24,049	**1,098**	947	1,372
Intersegment sales	**3,802**	3,328	5,403	**1,973**	1,535	2,892	**285**	289	460
Investment and other income	**59**	39	18	**81**	53	271	**3**	-	1
	8,144	6,919	11,240	**21,619**	18,381	27,212	**1,386**	1,236	1,833
Expenses									
Exploration	**191**	153	132	**-**	-	-	**-**	-	-
Purchases of crude oil and products	**2,692**	2,024	3,995	**17,169**	14,164	22,223	**1,009**	898	1,401
Production and manufacturing	**2,375**	2,385	2,569	**1,413**	1,372	1,452	**209**	194	208
Selling and general (b)	**5**	4	6	**918**	952	998	**63**	67	72
Federal excise tax	**-**	-	-	**1,316**	1,268	1,312	**-**	-	-
Depreciation and depletion	**514**	536	474	**213**	225	234	**12**	12	12
Financing costs (note 13)	**3**	1	2	**1**	2	(5)	**-**	-	-
Total expenses	**5,780**	5,103	7,178	**21,030**	17,983	26,214	**1,293**	1,171	1,693
Income before income taxes	**2,364**	1,816	4,062	**589**	398	998	**93**	65	140
Income taxes (note 4)									
Current	**477**	475	1,051	**141**	234	(56)	**18**	20	37
Deferred	**123**	17	88	**6**	(114)	258	**6**	(1)	3
Total income tax expense	**600**	492	1,139	**147**	120	202	**24**	19	40
Net income	**1,764**	1,324	2,923	**442**	278	796	**69**	46	100
Cash flow from (used in) operating activities	**2,494**	972	3,699	**787**	658	280	**65**	67	183
Capital and exploration expenditures	**3,844**	2,167	1,110	**184**	251	232	**10**	15	13
Property, plant and equipment									
Cost	**21,990**	18,455	16,344	**6,933**	6,901	6,776	**758**	748	732
Accumulated depreciation and depletion	**(9,740)**	(9,340)	(8,832)	**(3,678)**	(3,572)	(3,452)	**(546)**	(530)	(514)
Net property, plant and equipment (c)	**12,250**	9,115	7,512	**3,255**	3,329	3,324	**212**	218	218
Total assets (d)	**13,852**	10,663	8,758	**6,315**	6,183	6,038	**425**	428	431

	Corporate and other			Eliminations			Consolidated		
millions of dollars	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Revenues and other income									
Operating revenues (a)	**-**	-	-	**-**	-	-	**24,946**	21,292	31,240
Intersegment sales	**-**	-	-	**(6,060)**	(5,152)	(8,755)	**-**	-	-
Investment and other income	**3**	14	49	**-**	-	-	**146**	106	339
	3	14	49	**(6,060)**	(5,152)	(8,755)	**25,092**	21,398	31,579

Expenses									
Exploration	**-**	-	-	**-**	-	-	**191**	153	132
Purchases of crude oil and products	**-**	-	-	**(6,059)**	(5,152)	(8,754)	**14,811**	11,934	18,865
Production and manufacturing	**-**	-	-	**(1)**	-	(1)	**3,996**	3,951	4,228
Selling and general (b)	**84**	83	(38)	**-**	-	-	**1,070**	1,106	1,038
Federal excise tax	**-**	-	-	**-**	-	-	**1,316**	1,268	1,312
Depreciation and depletion	**8**	8	8	**-**	-	-	**747**	781	728
Financing costs (note 13)	**3**	2	3	**-**	-	-	**7**	5	-
Total expenses	**95**	93	(27)	**(6,060)**	(5,152)	(8,755)	**22,138**	19,198	26,303
Income before income taxes	**(92)**	(79)	76	**-**	-	-	**2,954**	2,200	5,276
Income taxes (note 4)									
Current	**(47)**	(35)	(27)	**-**	-	-	**589**	694	1,005
Deferred	**20**	25	44	**-**	-	-	**155**	(73)	393
Total income tax expense	**(27)**	(10)	17	**-**	-	-	**744**	621	1,398
Net income	**(65)**	(69)	59	**-**	-	-	**2,210**	1,579	3,878
Cash flow from (used in) operating activities	**(139)**	(106)	101	**-**	-	-	**3,207**	1,591	4,263
Capital and exploration expenditures	**7**	5	8	**-**	-	-	**4,045**	2,438	1,363
Property, plant and equipment									
Cost	**323**	317	313	**-**	-	-	**30,004**	26,421	24,165
Accumulated depreciation and depletion	**(135)**	(127)	(119)	**-**	-	-	**(14,099)**	(13,569)	(12,917)
Net property, plant and equipment (c)	**188**	190	194	**-**	-	-	**15,905**	12,852	11,248
Total assets (d)	**314**	546	1,982	**(326)**	(347)	(174)	**20,580**	17,473	17,035

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Notes to consolidated financial statements (continued)

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

millions of dollars	**2010**	2009	2008
Upstream	**1,759**	1,671	3,095
Downstream	**1,227**	1,266	1,685
Chemical	**664**	518	844
Total export sales	**3,650**	3,455	5,624

(b) Consolidated selling and general expenses include delivery costs from final storage areas to customers of $280 million in 2010 (2009 - $276 million, 2008 - $314 million).
(c) Includes property, plant and equipment under construction of $6,070 million (2009 - $2,927 million).
(d) All goodwill has been assigned to the Downstream segment. There have been no goodwill acquisitions, impairment losses or write-offs due to sales in the past three years.

4. Income taxes

millions of dollars	**5,624 2010**	**5,624** 2009	**5,624** 2008
Current income tax expense	**589**	694	1,005
Deferred income tax expense (a)	**155**	(73)	393
Total income tax expense (b)	**744**	621	1,398
Statutory corporate tax rate (percent)	**27.0**	28.7	29.5
Increase/(decrease) resulting from:			
Enacted tax rate change	**-**	0.2	-
Other	**(1.8)**	(0.7)	(3.0)
Effective income tax rate	**25.2**	28.2	26.5

(a) There were no material net (charges)/credits for the effect of changes in tax laws and rates included in the provisions for deferred income taxes in 2010, 2009 and 2008.
(b) Cash outflow from income taxes, plus investment credits earned, was $603 million in 2010 (2009 $1,330 million, 2008 $1,101 million).

Income taxes (charged)/credited directly to shareholders equity were:

millions of dollars	**5,624 2010**	**5,624** 2009	**5,624** 2008
Post-retirement benefits liability adjustment:			
Net actuarial loss/(gain)	**74**	160	102
Amortization of net actuarial (loss)/gain	**(35)**	(29)	(26)
Amortization of prior service cost	**(4)**	(4)	(5)

Total post-retirement benefits liability adjustment	**35**	127	71

Deferred income taxes are based on differences between the accounting and tax values of assets and liabilities. These differences in value are re-measured 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:

	5,624	5,624	5,624
millions of dollars	**2010**	2009	2008
Depreciation and amortization	**1,790**	1,691	1,685
Successful drilling and land acquisitions	**330**	305	258
Pension and benefits	**(414)**	(427)	(312)
Site restoration	**(224)**	(233)	(202)
Capitalized interest	**48**	49	53
Other	**16**	11	7
Deferred income tax liabilities	**1,546**	1,396	1,489
LIFO inventory valuation	**(450)**	(403)	(301)
Other	**(48)**	(64)	(60)
Deferred income tax assets	**(498)**	(467)	(361)
Valuation allowance	**-**	-	-
Net deferred income tax liabilities	**1,048**	929	1,128

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Notes to consolidated financial statements (continued)

Unrecognized tax benefits

Unrecognized tax benefits reflect the difference between positions taken on tax returns and the amounts recognized in the financial statements. Resolution of the related tax positions will take many years to complete. It is difficult to predict the timing of resolution for tax positions, since such timing is not entirely within the control of the company. The company s effective tax rate will be reduced if any of these tax benefits are subsequently recognized.

The following table summarizes the movement in unrecognized tax benefits:

millions of dollars	**2010**	2009	2008
January 1 balance	**165**	150	170
Additions based on current year s tax position	**24**	-	-
Additions for prior years tax positions	**-**	17	9
Reductions for prior years tax positions	**(37)**	(2)	(29)
Reductions due to lapse of the statute of limitations	**(5)**	-	-
December 31 balance	**147**	165	150

The 2010, 2009 and 2008 changes in unrecognized tax benefits did not have a material effect on the company s net income or cash flow. The company s tax filings from 2006 to 2009 are subject to examination by the tax authorities. The Canada Revenue Agency has proposed certain adjustments to the company s filings for several years in the period 1994 to 2005. Management is currently evaluating those proposed adjustments. Management believes that a number of outstanding matters before 2006 are expected to be resolved in 2011. The impact on unrecognized tax benefits and the company s effective income tax rate from these matters is not expected to be material.

The company classifies interest on income tax related balances as interest expense or interest income and classifies tax related penalties as operating expense.

5. 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.

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 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.

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Notes to consolidated financial statements (continued)

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

	(1,266)	(1,266)	(1,266)	(1,266)
	Pension benefits		Other post-retirement benefits	
	2010	2009	**2010**	2009
Assumptions used to determine benefit obligations at December 31 (percent)				
Discount rate	**5.50**	6.25	**5.50**	6.25
Long-term rate of compensation increase	**4.50**	4.50	**4.50**	4.50
millions of dollars				
Change in projected benefit obligation				
Projected benefit obligation at January 1	**5,056**	4,136	**426**	372
Current service cost	**102**	80	**5**	4
Interest cost	**307**	303	**24**	26
Actuarial loss/(gain)	**420**	834	**(11)**	47
Benefits paid (a)	**(323)**	(297)	**(23)**	(23)
Projected benefit obligation at December 31	**5,562**	5,056	**421**	426
Accumulated benefit obligation at December 31	**5,001**	4,520		

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 4.50 percent in 2011 and subsequent years.

	Pension benefits		Other post-retirement benefits	
millions of dollars	**2010**	2009	**2010**	2009
Change in plan assets				
Fair value at January 1	**3,753**	3,312		
Actual return/(loss) on plan assets	**393**	520		
Company contributions	**421**	180		
Benefits paid (b)	**(271)**	(259)		
Fair value at December 31	**4,296**	3,753		
Plan assets in excess of/(less than) projected benefit obligation at December 31				
Funded plans	**(796)**	(880)		
Unfunded plans	**(470)**	(423)	**(421)**	(426)

Total (c)	**(1,266)**	(1,303)	**(421)**	(426)

(a) Benefit payments for funded and unfunded plans.

(b) Benefit payments for funded plans only.

(c) Fair value of assets less projected benefit obligation shown above.

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. In accordance with authoritative guidance relating to the accounting for defined pension and other post-retirement benefits plans, the underfunded status of the company s defined benefit post-retirement plans was recorded as a liability in the balance sheet, and the changes in that funded status in the year in which the changes occurred was recognized through other comprehensive income.

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Notes to consolidated financial statements (continued)

millions of dollars	Pension benefits **2010**	2009	2008	Other post-retirement benefits **2010**	2009	2008
Amounts recorded in the consolidated balance sheet consist of:						
Current liabilities	**(21)**	(23)	(22)	**(26)**	(24)	(23)
Other long-term obligations	**(1,245)**	(1,280)	(802)	**(395)**	(402)	(349)
Total recorded	**(1,266)**	(1,303)	(824)	**(421)**	(426)	(372)
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	**1,965**	1,801	1,331	**15**	24	(25)
Prior service cost	**43**	59	77	**-**	-	-
Total recorded in accumulated other comprehensive income, before tax	**2,008**	1,860	1,408	**15**	24	(25)

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 2010 long-term expected return of 7.00 percent used in the calculations of pension expense compares to an actual rate of return of 5.5 percent and 8.8 percent over the last 10- and 20-year periods ending December 31, 2010.

	1,245)	**1,245)**	**1,245)**	**1,245)**	**1,245)**	**1,245)**
	Pension benefits **2010**	2009	2008	Other post-retirement benefits **2010**	2009	2008
Assumptions used to determine net periodic benefit cost for years ended December 31 (percent)						
Discount rate	**6.25**	7.50	5.75	**6.25**	7.50	5.75
Long-term rate of return on funded assets	**7.00**	8.00	8.00	**-**	-	-
Long-term rate of compensation increase	**4.50**	4.50	3.50	**4.50**	4.50	3.50

millions of dollars						
Components of net periodic benefit cost						
Current service cost	**102**	80	94	**5**	4	6
Interest cost	**307**	303	271	**24**	27	25
Expected return on plan assets	**(275)**	(267)	(330)	**-**	-	-
Amortization of prior service cost	**17**	17	19	**(1)**	-	-
Recognized actuarial loss/(gain)	**137**	112	91	**-**	(2)	6
Net periodic benefit cost	**288**	245	145	**28**	29	37

Changes in amounts recorded in accumulated other comprehensive income						
Net actuarial loss/(gain)	**302**	581	446	**(11)**	47	(61)
Amortization of net actuarial (loss)/gain included in net periodic benefit cost	**(137)**	(112)	(91)	**-**	2	(5)
Prior service cost	**-**	-	-	**-**	-	-
Amortization of prior service cost included in net periodic benefit cost	**(17)**	(17)	(19)	**1**	-	-
Total recorded in accumulated other comprehensive income	**148**	452	336	**(10)**	49	(66)
Total recorded in net periodic benefit cost and accumulated other comprehensive income, before tax	**436**	697	481	**18**	78	(29)

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Notes to consolidated financial statements (continued)

Costs for defined contribution plans, primarily the employee savings plan, were $37 million in 2010 (2009 - $36 million, 2008 - $33 million).

A summary of the change in accumulated other comprehensive income is shown in the table below:

millions of dollars	Total pension and other post-retirement benefits 2010	2009	2008
(Charge)/credit to accumulated other comprehensive income, before tax	**(138)**	(501)	(270)
Deferred income tax (charge)/credit (note 4)	**35**	127	71
(Charge)/credit to accumulated other comprehensive income, after tax	**(103)**	(374)	(199)

The company s investment strategy for pension 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 portfolio. Consistent with the long-term nature of the liability, the plan assets are primarily invested in global, market-cap-weighted indexed equity and domestic indexed bond funds to diversify risk while minimizing costs. The equity funds hold Imperial Oil stock only to the extent necessary to replicate the relevant equity index. The balance of the plan assets is largely invested in high-quality corporate and government debt securities. Studies are periodically conducted to establish the preferred target asset allocation. The target asset allocation for equity securities is 55 percent. The target allocation for debt securities is 40 percent. Plan assets for the remaining 5 percent are invested in venture capital partnerships that pursue a strategy of investment in U.S. and international early stage ventures.

The 2010 fair value of the pension plan assets, including the level within the fair value hierarchy, is shown in the table below:

		Fair value measurements at December 31, 2010, using:			
millions of dollars	Total	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)		Significant unobservable inputs (Level 3)
Asset class					
Equity securities					
Canadian	1,078		1,078	(a)	
Non-Canadian	1,392		1,392	(a)	
Debt securities-Canadian					
Corporate	439		439	(b)	
Government	1,229		1,229	(b)	
Asset backed	19		19	(b)	

Private mortgages	1				1	(c)
Equities Venture capital	110				110	(d)
Cash	28	25	3	(e)		
Total plan assets at fair value	4,296	25	4,160		111	

(a) For company equity securities held in the form of fund units that are redeemable at the measurement date, the unit value is treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchanges, which are Level 1 inputs.

(b) For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transactions.

(c) For private mortgages, fair value is estimated to equal the principal outstanding at measurement date.

(d) For venture capital partnership investments, fair value is generally established by using revenue or earnings multiples or other relevant market data including Initial Public Offerings.

(e) For cash balances that are held in Level 2 funds prior to investment in those fund units, the cash value is treated as a Level 2 input.

Notes to consolidated financial statements (continued)

The change in the fair value of Level 3 assets, which use significant unobservable inputs to measure fair value, is shown in the table below:

millions of dollars	Private mortgages	Venture capital
Fair value at January 1, 2010	2	95
Net realized gains/(losses)	(1)	(3)
Net unrealized gains/(losses)	1	2
Net purchases/(sales)	(1)	16
Fair value at December 31, 2010	1	110

The 2009 fair value of the pension plan assets, including the level within the fair value hierarchy, is shown in the table below:

		Fair value measurements at December 31, 2009, using:				
millions of dollars	Total	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)		Significant unobservable inputs (Level 3)	
Asset class						
Equity securities						
Canadian	918		918	(a)		
Non-Canadian	1,218		1,218	(a)		
Debt securities - Canadian						
Corporate	386		386	(b)		
Government	1,102		1,102	(b)		
Asset backed	20		20	(b)		
Private mortgages	2				2	(c)
Equities Venture capital	95				95	(d)
Cash	12	9	3	(e)		
Total plan assets at fair value	3,753	9	3,647		97	

(a) For company equity securities held in the form of fund units that are redeemable at the measurement date, the unit value is treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchanges, which are Level 1 inputs.
(b) For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transactions.
(c) For private mortgages, fair value is based on market data and year-end surveys of active brokers.
(d) For venture capital partnership investments, fair value is generally established by using revenue or earnings multiples or other relevant market data including Initial Public Offerings.

(e) For cash balances that are held in Level 2 funds prior to investment in those fund units, the cash value is treated as a Level 2 input.

The change in the fair value of Level 3 assets, which use significant unobservable inputs to measure fair value, is shown in the table below:

millions of dollars	Private mortgages	Venture capital
Fair value at January 1, 2009	2	112
Net realized gains/(losses)	-	(9)
Net unrealized gains/(losses)	-	(20)
Net purchases/(sales)	-	12
Fair value at December 31, 2009	2	95

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Notes to consolidated financial statements (continued)

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

millions of dollars	Other post-retirement Pension benefits **2010**	Other post-retirement 2009
For funded pension plans with accumulated benefit obligations in excess of plan assets:		
Projected benefit obligation	**5,092**	4,633
Accumulated benefit obligation	**4,584**	4,155
Fair value of plan assets	**4,296**	3,753
Accumulated benefit obligation less fair value of plan assets	**288**	402
For unfunded plans covered by book reserves:		
Projected benefit obligation	**470**	423
Accumulated benefit obligation	**416**	365

Estimated 2011 amortization from accumulated other comprehensive income

millions of dollars	Pension benefits	Other post-retirement benefits
Net actuarial loss/(gain) (a)	156	2
Prior service cost (b)	16	-

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

Cash flows

Benefit payments expected in:

	Pension benefits	Other post-retirement benefits
2011	291	25
2012	299	25
2013	308	25
2014	319	25
2015	330	25
2016 - 2020	1,799	127

In 2011, the company expects to make cash contributions of about $350 million to its pension plans.

Sensitivities

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

Increase/(decrease) millions of dollars	Other post-retirement One percent increase	Other post-retirement One percent decrease
Rate of return on plan assets:		
Effect on net benefit cost, before tax	(40)	40
Discount rate:		
Effect on net benefit cost, before tax	(55)	65
Effect on benefit obligation	(670)	825
Rate of pay increases:		
Effect on net benefit cost, before tax	30	(30)
Effect on benefit obligation	155	(140)

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Notes to consolidated financial statements (continued)

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	3	(2)
Effect on benefit obligation	34	(28)

6. Other long-term obligations

millions of dollars	**2010**	2009
Employee retirement benefits (note 5)(a)	**1,640**	1,682
Asset retirement obligations and other environmental liabilities (b)	**754**	806
Share-based incentive compensation liabilities (note 8)	**127**	144
Other obligations	**232**	207
Total other long-term obligations	**2,753**	2,839

(a) Total recorded employee retirement benefit obligations also include $47 million in current liabilities (2009 $47 million).
(b) Total asset retirement obligations and other environmental liabilities also include $134 million in current liabilities (2009 $114 million).

Asset retirement obligations incurred in the current period were Level 3 (unobservable inputs) fair value measurements. The following table summarizes the activity in the liability for asset retirement obligations:

millions of dollars	**2010**	2009
January 1 balance	**810**	711
Additions	**-**	135
Accretion	**48**	42
Settlement	**(85)**	(78)
December 31 balance	**773**	810

7. Derivatives and financial instruments

The company did not enter into any derivative instruments to offset exposures associated with hydrocarbon prices, foreign currency exchange rates and interest rates that arose from existing assets, liabilities and transactions in the past three years. The company did not engage in speculative derivative activities or derivative trading activities nor did it use derivatives with leveraged features. 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 and the recorded book value. The fair value hierarchy for long-term debt is primarily Level 2 (observable input).

8. 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.

Restricted stock units, deferred share units and incentive share units

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. The company may also issue units where 50 percent of the units are exercisable five years following the grant date and the remainder are exercisable on the later of ten years following the grant date or the retirement date of the recipient. For units granted in 2004 to 2005, the exercise date has been changed from December 31 to December 4 for units exercised in 2007 and subsequent years. For units granted in 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 a factor of three.

Notes to consolidated financial statements (continued)

The deferred share unit plan is made available to nonemployee directors. The nonemployee directors can elect to receive all or part of their directors fees in units. The number of units granted is determined at the end of each calendar quarter by dividing the dollar amount of the nonemployee director s fees for that calendar quarter elected to be received 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 resignation as a director and must be exercised no later than December 31 of the year following 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.

The company s incentive share units give the recipient a right to receive cash equal to the amount by which the market price of the company s common shares at the time of exercise exceeds the issue price of the units. These units were granted prior to 2002. The issue price of the units granted to recipients was the closing price of the company s shares on the Toronto Stock Exchange on the grant date. Incentive share units are eligible for exercise up to 10 years from issuance. The last grant expires in 2011.

All units require settlement by cash payments with the following exceptions. The restricted stock unit program was amended for units granted in 2002 and subsequent 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. For units where 50 percent are exercisable five years following the grant date and the remainder exercisable on the later of ten years following the grant date or the retirement date of the recipient, the recipient may receive one common share of the company per unit or elect to receive cash payment for all units to be exercised.

The company accounts for all units by using the fair-value-based method. The fair value of awards in the form of restricted stock, deferred share and incentive share units is the market price of the company s stock. 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 requisite service period of each award.

The following table summarizes information about these units for the year ended December 31, 2010:

	Restricted stock units	Deferred share units	Incentive share units
Outstanding at January 1, 2010	**10,229,977**	**75,770**	**4,423,695**
Granted	**1,820,528**	**9,949**	**-**
Exercised	**(2,139,844)**	**-**	**(2,226,345)**
Forfeited and canceled	**(10,303)**	**-**	**-**
Outstanding at December 31, 2010	**9,900,358**	**85,719**	**2,197,350**

The compensation expense charged against income for these programs was $57 million and $59 million for the years ended December 31, 2010 and 2009, respectively, and there was a $33 million favourable adjustment to previously recorded compensation expenses for these programs in the year ended December 31, 2008. Income tax benefit recognized in income related to compensation expense for the years ended December 31, 2010 and 2009 was $27 million and $24 million, respectively, and income tax expense associated with the favourable adjustment to compensation expense for the year ended December 31, 2008 was $5 million. Cash payments of $152 million, $126 million and $115 million for these programs were made in 2010, 2009 and 2008, respectively.

As of December 31, 2010, there was $195 million of total before-tax unrecognized compensation expense 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, 2010.

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Notes to consolidated financial statements (continued)

Incentive stock options

In April 2002, incentive stock options were granted for the purchase of the company s common shares. For units exercised subsequent to the company s May 2006 three-for-one split, the company has indicated that it will give the option holders the right to purchase three shares for each original stock option granted. The exercise price is $15.50 per share (adjusted to reflect the three-for-one share split). All options have vested as of December 31, 2010. 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.

Since incentive stock option awards vested prior to the effective date of current authoritative guidance relating to accounting for stock-based compensation, they continue to be accounted for under the prior prescribed method. Under this method, compensation expense of incentive stock option awards is not recognized, as the exercise price of the option is equal to the market price of the stock on the date of grant.

The aggregate intrinsic value of stock options exercised was $5 million, $1 million and $17 million in the years ended December 31, 2010, 2009 and 2008, respectively, and for the outstanding stock options was $101 million as at December 31, 2010.

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. Purchase may be discontinued at any time without prior notice.

The following table summarizes information about stock options for the year ended December 31, 2010:

	Units	Exercise price (dollars)	Remaining contractual term (years)
Incentive stock options			
Outstanding at January 1, 2010	**4,240,830**	**15.50**	
Granted	**-**		
Exercised	**(207,084)**	**15.50**	
Forfeited and canceled	**-**		
Outstanding at December 31, 2010	**4,033,746**	**15.50**	**1.3**

9. Investment and other income

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

millions of dollars	**term (years)** **2010**	**term (years)** 2009	**term (years)** 2008
Proceeds from asset sales	**144**	67	272
Book value of assets sold	**49**	22	31

Gain/(loss) on asset sales, before tax (a)	**95**	45	241
Gain/(loss) on asset sales, after tax (a)	**80**	38	209

(a) 2008 included a gain of $219 million ($187 million, after tax) from the sale of the company s equity investment in Rainbow Pipe Line Co. Ltd.

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Notes to consolidated financial statements (continued)

10. Litigation and other contingencies

A variety of claims have been made against Imperial Oil Limited and its subsidiaries in a number of lawsuits. Management has regular litigation reviews, including updates from corporate and outside counsel, to assess the need for accounting recognition or disclosure of these contingencies. The company accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The company does not record liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavourable outcome is reasonably possible and which are significant, the company discloses the nature of the contingency and, where feasible, an estimate of the possible loss. 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, financial condition, or financial statements taken as a whole.

Additionally, the company has other commitments arising in the normal course of business for operating and capital needs, all of which are expected to be fulfilled with no adverse consequences material to the company s operations or financial condition. Unconditional purchase obligations, as defined by accounting standards, are those long-term commitments that are non-cancelable or cancelable only under certain conditions and that third parties have used to secure financing for the facilities that will provide the contracted goods and services.

	Payments due by period						
millions of dollars	2011	2012	2013	2014	2015	After 2015	Total
Unconditional purchase obligations (a)	**66**	**34**	**34**	**33**	**33**	**173**	**373**

(a) Undiscounted obligations of $373 million mainly pertain to pipeline throughput agreements. Total payments under unconditional purchase obligations were $78 million (2009 - $74 million, 2008 - $117 million). The present value of these commitments, excluding imputed interest of $86 million, totaled $287 million.

11. Common shares

thousands of shares	**As at Dec. 31 2010**	As at Dec. 31 2009
Authorized	**1,100,000**	1,100,000

From 1995 through 2009, the company purchased shares under fifteen 12-month normal course issuer bid share repurchase programs, as well as an auction tender. On June 25, 2010, another 12-month normal course issuer bid program was implemented with an allowable purchase of up to about 42 million shares, less shares purchased from Exxon Mobil Corporation and shares purchased by the employee savings plan and company pension fund. The results of these activities are as shown below.

Year	Purchased shares (thousands)	Millions of dollars

1995 to 2008	890,434	15,021
2009	11,861	492
2010	**208**	**8**
Cumulative purchases to date	902,503	15,521

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 earnings reinvested.

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Notes to consolidated financial statements (continued)

The company s common share activities are summarized below:

	Thousands of shares	Millions of dollars
Balance as at January 1, 2008	903,263	1,600
Issued for cash under the stock option plan	434	7
Purchases at stated value	(44,295)	(79)
Balance as at December 31, 2008	859,402	1,528
Issued under employee share-based awards	58	1
Purchases at stated value	(11,861)	(21)
Balance as at December 31, 2009	847,599	1,508
Issued under employee share-based awards	**208**	**3**
Purchases at stated value	**(208)**	**-**
Balance as at December 31, 2010	**847,599**	**1,511**

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

	Thousands of **2010**	Thousands of 2009	Thousands of 2008
Net income per common share basic			
Net income (millions of dollars)	**2,210**	1,579	3,878
Weighted average number of common shares outstanding (millions of shares)	**847.6**	849.8	882.6
Net income per common share (dollars)	**2.61**	1.86	4.39
Net income per common share - diluted			
Net income (millions of dollars)	**2,210**	1,579	3,878
Weighted average number of common shares outstanding (millions of shares)	**847.6**	849.8	882.6
Effect of employee share-based awards (millions of shares)	**6.6**	6.9	6.4
Weighted average number of common shares outstanding, assuming dilution (millions of shares)	**854.2**	856.7	889.0
Net income per common share (dollars)	**2.59**	1.84	4.36

12. Miscellaneous financial information

In 2010, net income included an after-tax gain of $38 million (2009 $46 million gain, 2008 $27 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, 2010 by $1,859 million (2009 $1,579 million). Inventories of crude oil and products at year-end consisted of the following:

millions of dollars	**2010**	2009
Crude oil	**285**	312
Petroleum products	**180**	186
Chemical products	**52**	53
Natural gas and other	**10**	13
Total inventories of crude oil and products	**527**	564

Research and development costs before investment tax credits in 2010 were $107 million (2009 $98 million, 2008 $83 million). These costs are included in expenses due to the uncertainty of future benefits. Investment tax credits earned on these expenditures were not significant.

Cash flow from operating activities included dividends of $9 million received from equity investments in 2010 (2009 $14 million, 2008 $11 million).

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Notes to consolidated financial statements (continued)

13. Financing costs

millions of dollars	**2010**	2009	2008
Debt-related interest	**6**	5	8
Capitalized interest	**(6)**	(5)	(8)
Net interest expense	**-**	-	-
Other interest	**7**	5	-
Total financing costs (a)	**7**	5	-

(a) Cash interest payments in 2010 were $12 million (2009 $8 million, 2008 $6 million). The weighted average interest rate on short-term borrowings in 2010 was 0.7 percent (2009 0.7 percent).

14. Leased facilities

At December 31, 2010, the company held non-cancelable operating leases covering office buildings, rail cars, service stations and other properties with minimum undiscounted lease commitments totaling $270 million as indicated in the following table:

	Payments due by period						
millions of dollars	2011	2012	2013	2014	2015	After 2015	Total
Lease payments under minimum commitments (a)	**61**	**49**	**44**	**40**	**37**	**39**	**270**

(a) Total rental expenditures incurred for operating leases in 2010 were $173 million (2009 $129 million, 2008 $149 million), which included minimum rental expenditures of $173 million (2009 - $128 million, 2008 - $140 million). Related rental income was not material.

15. Long-term debt

millions of dollars	**As at Dec. 31 2010**	As at Dec. 31 2009
Long-term debt (a)	**500**	-
Capital leases (b)	**27**	31
Total long-term debt	**527**	31

(a) In 2010, the company borrowed $500 million under an existing agreement with an affiliated company of Exxon Mobil Corporation (ExxonMobil) that provides for a long-term, variable-rate loan from ExxonMobil to the company of up to $5 billion (Canadian) at interest equivalent to Canadian market rates. The agreement is effective until July 31, 2020, cancelable if ExxonMobil provides at least 370 days advance written notice. Average effective rate for the loan was 1.1 percent in 2010.

(b)

Capitalized lease 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 11.2 percent in 2010 (2009 11.1 percent). Total capitalized lease obligations also include $4 million in current liabilities (2009 - $4 million). Principal payments on capital leases of approximately $4 million a year are due in each of the next five years.

In the third quarter of 2010, to support the commercial paper program, the company entered into an unsecured committed bank credit facility in the amount of $200 million that matures in July 2012. The company has not drawn on this facility.

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Notes to consolidated financial statements (continued)

16. Accounting for suspended exploratory well costs

The company continues capitalization of exploratory well costs beyond one year after the well is completed if (a) the well found a sufficient quantity of reserves to justify its completion as a producing well and (b) sufficient progress is being made in assessing the reserves and the economic and operating viability of the project.

The following two tables provide details of the changes in the balance of suspended exploratory well costs as well as an aging summary of those costs.

Change in capitalized suspended exploratory well costs:

millions of dollars	**2010**	2009	2008
January 1 balance	**45**	-	-
Additions pending the determination of proved reserves	**75**	45	-
Charged to expense	**-**	-	-
Reclassification to wells, facilities and equipment based on the determination of proved reserves	**-**	-	-
December 31 balance	**120**	45	-

Period end capitalized suspended exploratory well costs:

millions of dollars	**2010**	2009	2008
Capitalized for a period of one year or less	**75**	45	-
Capitalized for a period of between one and five years	**45**	-	-
Capitalized for a period of greater than one year	**45**	-	-
Total	**120**	45	-

Exploration activity often involves drilling multiple wells, over a number of years, to fully evaluate a project. The table below provides a numerical breakdown of the number of projects with suspended exploratory well costs which had their first capitalized well drilled in the preceding 12 months and those that have had exploratory well costs capitalized for a period greater than 12 months.

	2010	2009	2008
Number of projects with first capitalized well drilled in the preceding 12 months	-	1	-
Number of projects that have exploratory well costs capitalized for a period of greater than 12 months	**1**	-	-
Total	**1**	1	-

The project with exploratory well costs capitalized for a period greater than 12 months as of December 31, 2010 has drilling in the preceding 12 months.

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Notes to consolidated financial statements (continued)

17. 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, petroleum and chemical products, as well as technical, engineering and research and development costs. Transactions with ExxonMobil also included amounts paid and received in connection with the company s participation in a number of upstream activities conducted jointly in Canada.

In addition, the company has existing agreements with ExxonMobil to:

a) 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;

b) operate the Western Canada production properties owned by ExxonMobil as well as provide for the delivery of management, business and technical services to ExxonMobil in Canada. These agreements are designed to provide organizational efficiencies and to reduce costs. No separate legal entities were created from these arrangements. Separate books of account continue to be maintained for the company and ExxonMobil. The company and ExxonMobil retain ownership of their respective assets, and there is no impact on operations or reserves;

c) provide for the delivery of management, business and technical services to Syncrude Canada Ltd. by ExxonMobil; and

d) provide for equal participation in new upstream opportunities.

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

As at December 31, 2010, the company had outstanding loans of $500 million (2009 - nil) from ExxonMobil (see note 15, long-term debt, on page 73 for further details).

As at December 31, 2010, the company had outstanding loans of $30 million (2009 - $33 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.

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Supplemental information on oil and gas exploration and production activities (unaudited)

The information on pages 76 to 78 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.

Beginning in 2009, the company s 25 percent interest in proved synthetic oil reserves in the Syncrude joint-venture and 70.96 percent interest in proved bitumen reserves in the Kearl project are included as part of the company s total proved oil and gas reserves in accordance with U.S. Securities and Exchange Commission (SEC) and U.S. Financial Accounting Standards Board (FASB) rules. These reserves were reported as mining proven reserves, separate from proved oil and gas reserves, prior to 2009. Similarly, the company s share of proved synthetic oil reserves from Syncrude and proved bitumen reserves from Kearl are included in the calculation of the standard measure of discounted future cash flows beginning in 2009. They were excluded in the 2008 calculations. Beginning in 2009, results of operations, costs incurred in property acquisitions, exploration and development activities, and capitalized costs include the company s share of Syncrude, Kearl and other unproved mineable acreages in the following tables. They were excluded in 2008.

Results of operations

millions of dollars	**2010**	2009	2008
Sales to customers (a)	**2,094**	1,887	3,343
Intersegment sales (a)(b)	**3,165**	2,822	1,297
	5,259	4,709	4,640
Production expenses	**2,225**	2,212	1,335
Exploration expenses	**190**	151	122
Depreciation and depletion	**521**	540	337
Income taxes	**591**	489	814
Results of operations (c)	**1,732**	1,317	2,032

Costs incurred in property acquisitions, exploration and development activities

millions of dollars	**2010**	2009	2008
Property costs (d)			
Proved	**-**	-	-
Unproved	**70**	191	66
Exploration costs	**260**	233	133
Development costs	**3,515**	1,878	631
Total costs incurred in property acquisitions, exploration and development activities (e)	**3,845**	2,302	830

The amounts reported as costs incurred in property acquisitions, exploration and development activities include both capitalized costs and costs charged to expense during the year. Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligation resulting from changes in cost estimates or abandonment date.

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Supplemental information on oil and gas exploration and production activities (unaudited) (continued)

Capitalized costs

millions of dollars	**2010**	2009
Property costs (d)		
Proved	**3,163**	3,170
Unproved	**526**	482
Producing assets	**12,253**	11,847
Support facilities	**254**	237
Incomplete construction	**5,785**	2,710
Total capitalized cost	**21,981**	18,446
Accumulated depreciation and depletion	**(9,733)**	(9,332)
Net capitalized costs	**12,248**	9,114

(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 operating revenues , 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) In 2009, the impact of including the company s interests in Syncrude, Kearl and other unproved mineable acreages in results of operations was $1,625 million in sales and $308 million in earnings.

(d) 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.

(e) In 2009, costs incurred in property acquisitions, exploration and development activities included $1,464 million from the company s interests in Syncrude, Kearl and other unproved mineable acreages.

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Supplemental information on oil and gas exploration and production activities (unaudited) (continued)

Standardized measure of discounted future cash flows

As required by the FASB, the standardized measure of discounted future net cash flows was computed through 2008 by applying year-end prices, costs and legislated tax rates and a discount factor of 10 percent to net proved reserves. Beginning in 2009, the standardized measure of discounted future net cash flows was computed by applying first-day-of-the-month average prices, year-end 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 first-day-of-the-month average prices, which represent discrete points in time and therefore may cause significant variability in cash flows from year to year as prices change.

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

millions of dollars	**2010**	2009	2008
Future cash flows	**158,835**	138,279	18,956
Future production costs	**(62,051)**	(58,057)	(13,558)
Future development costs	**(16,920)**	(20,893)	(4,642)
Future income taxes	**(18,765)**	(14,307)	(111)
Future net cash flows	**61,099**	45,022	645
Annual discount of 10 percent for estimated timing of cash flows	**(39,848)**	(31,647)	613
Discounted future cash flows	**21,251**	13,375	1,258

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

Balance at beginning of year	**13,375**	1,258	6,250
Changes resulting from:			
Sales and transfers of oil and gas produced, net of production costs	**(3,130)**	(2,658)	(3,422)
Net changes in prices, development costs and production costs	**4,217**		