IMPERIAL OIL LTD
Form 10-K
February 27, 2009
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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, 2008 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 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 2008 second fiscal quarter, the aggregate market value of the voting stock held by non-affiliates of the registrant was Canadian $15,059,343,761 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 13, 2009, was 856,836,280.

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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 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.

	2008	2007	2006	2005	2004
			(dollars)		
Rate at end of period	**0.8170**	1.0120	0.8582	0.8579	0.8310
Average rate during period	**0.9335**	0.9376	0.8844	0.8276	0.7702
High	**1.0291**	1.0908	0.9100	0.8690	0.8493
Low	**0.7710**	0.8437	0.8528	0.7872	0.7158

On February 13, 2009, 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 $0.8042 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; financing sources; the resolution of contingencies and uncertain tax positions; the effect of changes in prices and other market conditions; and environmental and capital expenditures could differ materially depending on a number of factors, such as the outcome of commercial negotiations; changes in the supply of and demand for crude oil, natural gas, and petroleum and petrochemical products; political or regulatory events; and other factors discussed in Item 1A of the company s 2008 Form 10K and in the management s discussion and analysis of financial condition and results of operations contained herein.

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 one of the largest producers of crude oil, natural gas and natural gas liquids and the largest refiner and marketer of petroleum products. It is also a major supplier of petrochemicals.

Financial Information by Operating Segments (under U.S. GAAP)

	2008	**2007**	**2006**	**2005**	**2004**
External sales (1):			(millions of dollars)		
Upstream	**5,819**	4,539	4,619	4,702	3,689
Downstream	**24,049**	19,230	18,527	21,793	17,503
Chemical	**1,372**	1,300	1,359	1,302	1,216
	31,240	25,069	24,505	27,797	22,408
Intersegment sales:					
Upstream	**5,403**	4,146	3,837	3,487	2,891
Downstream	**2,892**	2,305	2,256	2,224	1,666
Chemical	**460**	335	345	363	293
Net income (2):					
Upstream	**2,923**	2,369	2,376	2,008	1,517
Downstream	**796**	921	624	694	556
Chemical	**100**	97	143	121	109
Corporate and other (3)/eliminations	**59**	(199)	(99)	(223)	(130)
	3,878	3,188	3,044	2,600	2,052
Identifiable assets at December 31 (4):					
Upstream	**8,758**	8,171	7,513	7,289	6,822
Downstream	**6,038**	6,727	6,450	6,257	5,509
Chemical	**431**	476	504	500	490
Corporate and other/eliminations	**1,808**	913	1,674	1,536	1,206
	17,035	16,287	16,141	15,582	14,027
Capital and exploration expenditures:					
Upstream	**1,110**	744	787	937	1,113
Downstream	**232**	187	361	478	283
Chemical	**13**	11	13	19	15
Corporate and other	**8**	36	48	41	34

	1,363	978	1,209	1,475	1,445

(1) Export sales are reported in note 3 to the consolidated financial statements on page F-9. Total external sales include $4,894 million for 2005 and $3,584 million for 2004 for purchases/sales contracts with the same counterparty. Associated costs were included in purchases of crude oil and products . Effective January 1, 2006, these purchases/sales were recorded on a net basis.

(2) 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.

(3) Includes primarily interest charges on the debt obligations of the company, interest income on investments and incentive compensation expenses.

(4) The identifiable assets in each operating segment represent the net book value of the tangible and intangible assets attributed to such segment. Net intangible assets representing unrecognized prior service costs associated with the recognition of the additional minimum pension liability in 2005 and 2004 have been reclassified from the operating segments to the corporate and other segment. Amounts reclassified into the corporate and other segment were $92 million for 2005 and $97 million in 2004. This change has no impact on total identifiable assets at December 31 of 2005 and 2004.

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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, upgraded crude oil and heavy oil. Downstream operations consist of the transportation, refining and blending of crude oil and refined products and the distribution and marketing thereof. The Chemical operations consist of the manufacturing and marketing of various petrochemicals.

Upstream

Petroleum and Natural Gas Production

The company s average daily production of crude oil and natural gas liquids during the five years ended December 31, 2008, was as follows:

		2008	2007	2006	2005	2004
Conventional (including natural gas liquids):				(thousands a day)		
Barrels	Gross (1)	**37**	45	55	69	76
Net (2)		**27**	33	42	54	59
Heavy Oil (3):						
Barrels	Gross (1)	**147**	154	152	139	126
Net (2)		**124**	130	127	124	112
Oil Sands (4):						
Barrels	Gross (1)	**72**	76	65	53	60
Net (2)		**62**	65	58	53	59
Total:						
Barrels	Gross (1)	**256**	275	272	261	262
Net (2)		**213**	228	227	231	230

(1) Gross production of crude oil is the company s share of production from conventional wells, Syncrude oil sands and Cold Lake heavy oil, and gross production of natural gas liquids is the amount derived from processing the company s share of production of natural gas (excluding purchased gas), in each case before deduction of the mineral owners or governments share or both.

(2) Net production is gross production less the mineral owners or governments share or both.

(3) Heavy oil typically is represented by crude oils with a viscosity of greater than 10,000 cP and recovered through enhanced thermal operations. The company s heavy oil production volumes are from Cold Lake production operations.

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

In 2005 and 2006 conventional production fell mainly due to the natural decline of the company s conventional fields. In 2007, the lower conventional production volume was primarily due to decline in the Wizard Lake field. In 2008, the conventional production volume was lower primarily due to the completion of the Wizard Lake blowdown.

Cold Lake production increased from 2004 to 2007 due to the timing of steaming cycles and increased volumes from the ongoing development drilling program. In 2008, Cold Lake production declined due to steam cycle timing and higher royalties.

In 2005 Syncrude production declined primarily due to increased maintenance for upgrading facilities. In 2006, Syncrude production increased due to lower maintenance activities and the start-up of expanded upgrading facilities. In 2007, Syncrude production increased with full year operation of the expanded upgrading facilities. In 2008, Syncrude production declined primarily due to increased planned and unplanned maintenance activities, including continuing work to improve reliability performance.

The company s average daily production and sales of natural gas during the five years ended December 31, 2008 are set forth below. All gas volumes in this report are calculated at a pressure base of 14.73 pounds per square inch absolute at 60 degrees Fahrenheit.

	2008	2007	2006 (millions a day)	2005	2004
Sales (1):					
Cubic feet	**288**	407	513	536	520
Gross Production (2):					
Cubic feet	**310**	458	556	580	569
Net Production (2):					
Cubic feet	**249**	404	496	514	518

(1) 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.

(2) Gross production of natural gas is the company s share of production (excluding purchases) before deducting the shares of mineral owners or governments or both. Net production excludes those shares. Production data include amounts used for internal consumption with the exception of amounts reinjected.

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In 2005, gross natural gas production increased due to increased production from the Nisku and Wizard Lake gas caps and the Medicine Hat gas field. In 2006, gas production decreased primarily due to natural decline. In 2007, the lower production volume was primarily due to decline in production from the gas cap at Wizard Lake. In 2008, the most significant reason for lower production volume was the completion of the Wizard Lake blowdown.

Most of the company s natural gas sales are made under short term contracts.

The company s average sales price and production costs for conventional crude oil, Cold Lake heavy oil and natural gas liquids and natural gas for the five years ended December 31, 2008, were as follows:

	2008	2007	2006	2005	2004
Average Sales Price:					
Crude oil and natural gas liquids:					
Dollars per barrel	**72.29**	45.16	45.13	37.21	32.95
Natural gas:					
Dollars per thousand cubic feet	**8.69**	6.95	7.24	9.00	6.78
Average Production Costs Per					
Unit of Net Production (1)(2):					
Dollars per barrel	**18.91**	12.75	11.08	10.78	9.25

(1) Average production costs per unit of production do not include depreciation and depletion of capitalized acquisition, exploration and development costs. Administrative expenses are included. Average production (lifting) costs per unit of net production were computed after converting gas production into equivalent units of oil on the basis of relative energy content.

(2) Unit production costs are sometimes referred to as lifting costs.

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

Canadian natural gas prices are determined by North American gas markets, which are also volatile, and the impact of foreign exchange rates. Natural gas prices throughout North America increased in the second half of 2005 due to supply disruptions from hurricane damage to facilities in the U.S. Gulf Coast.

In 2005, average unit production costs increased mainly due to higher costs of purchased natural gas at Cold Lake. In 2006, average production costs increased due to lower gas production and higher liquids royalties resulting in lower net liquids production. Liquids royalties were higher in the year due to increased realizations for Cold Lake production. In 2007, unit production costs were higher primarily as a result of lower gas and liquids volumes due to decline in production at Wizard Lake. In 2008, unit production costs were higher, primarily as a result of lower gas and liquids volumes due to production decline at Wizard Lake, and higher spending to improve reliability at Cold Lake.

The company has interests in a large number of facilities related to the production of crude oil and natural gas. Among these facilities are 19 plants that process natural gas to produce marketable gas and recover natural gas liquids or sulphur. In 2008, the number of plants for which the company is the principal owner and operator dropped from 10 to eight, with the shutdown of the plants at the Bonnie Glen field.

The company s production of conventional crude oil, Cold Lake heavy oil and natural gas is derived from wells located exclusively in Canada. The total number of producing wells in which the company had interests at December 31, 2008, is set forth in the following table. The statistics in the table are determined in part from information received from other operators.

	Crude Oil		Natural Gas		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Conventional wells	906	601	5,186	2,768	6,092	3,369
Heavy Oil wells	4,243	4,243	-	-	4,243	4,243

(1) Gross wells are wells in which the company owns a working interest.
(2) Net wells are the sum of the fractional working interests owned by the company in gross wells, rounded to the nearest whole number.

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 58 percent of the company s net production of conventional crude oil (approximately 63 percent of gross production). In 2008, net production of crude oil and natural gas liquids was about 11,300 barrels per day and gross production was about 17,000 barrels per 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 2008, those costs were about $36 million.

Most of the 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.

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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.

Cold Lake

The company holds about 194,000 net acres of heavy oil leases near Cold Lake, Alberta. To develop the technology necessary to produce this oil commercially, the company conducts experimental pilot operations to improve recovery of heavy oil from wells by means of new drilling and production techniques.

In late 1983, the company commenced the development, in phases, of its heavy oil resources at Cold Lake. During 2008, average net production at Cold Lake was about 123,800 barrels per day and gross production was about 146,700 barrels per day.

To maintain production at Cold Lake, capital expenditures for additional production wells and associated facilities will be required periodically. In 2008, the company spent $305 million and executed a development drilling program of 70 wells on existing phases. In 2009, 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 and design work is progressing on the Nabiye project, the next phase of expansion at Cold Lake that would add about 30,000 barrels a day of production before royalties.

Most of the production from Cold Lake is sold to refineries in the northern United States. The majority of the remainder of Cold Lake production is shipped to certain of the company s refineries and to a third-party heavy oil upgrader in Lloydminster, Saskatchewan.

The Province of Alberta, in its capacity as lessor of Cold Lake heavy oil leases, is entitled to a royalty on production at Cold Lake. The original royalty agreement, which applied through the end of 1999, provided for a royalty calculated at the greater of five percent of gross revenue or 30 percent of an amount based on revenue net of operating and capital costs. It also provided for a royalty waiver on equity natural gas produced in Alberta and deemed to be consumed in generating steam at the company s Cold Lake operations. Effective January 1, 2000, the company entered into an agreement with the Province of Alberta on a transitional royalty arrangement that applied to all of the company s operations at Cold Lake until the end of 2007, at which time the generic Alberta regulations for heavy oil royalties applied. The transition agreement made provision for the differences between the two royalty regimes (higher bitumen royalties with gas royalty waiver vs. lower bitumen royalties and no gas royalty waiver). The generic regulations, which were effective January 1, 2008, provided for a royalty calculated at the greater of one percent of gross revenue or 25 percent of an amount based on revenue net of operating and capital costs, and with no gas royalty waiver. The transition did not materially change the amount of royalties that the company would have otherwise paid under the pre-existing royalty arrangements. Cold Lake will be subject to the Alberta generic oil sand royalty regime, which was modified in 2007 and took effect in 2009. Royalty rates will be based upon a sliding scale, determined by the price of crude oil. The effective royalty on gross production was 16 percent in 2008, 15 percent in 2007, 17 percent in 2006, and 11 percent in 2005 and 2004.

Other Heavy Oil Activity

The company has interests in other heavy oil leases in the Athabasca and Peace River areas of northern Alberta, totaling about 170,000 net acres. Evaluation wells completed on these leased areas established the presence of heavy oil. The company continues to evaluate these leases to determine their potential for future development.

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Syncrude and Kearl Leases

Syncrude Mining 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 (see map), mines a portion of the Athabasca oil sands deposit. The location is readily accessible by public road. The produced synthetic crude oil is shipped from the Syncrude site to Edmonton, Alberta by Alberta Oil Sands Pipeline Ltd. Since startup in 1978, Syncrude has produced about 1.9 billion barrels of synthetic crude oil.

Syncrude has an operating license issued by the Province of Alberta which is effective until 2035. This license permits Syncrude to mine oil sands and produce synthetic crude oil from approved development areas on oil sands leases. Syncrude joint-venture owners hold eight oil sands leases covering about 250,000 acres in the Athabasca oil sands deposit. Issued by the Province of Alberta, the leases are automatically renewable as long as oil sands operations are ongoing or the leases are part of an approved development plan. Syncrude leases 10, 12, 17, 22 and 34 (containing proven reserves) and leases 29, 30 and 31 (containing no proven reserves) are included within a development plan approved by the Province of Alberta. There were no known previous commercial operations on these leases prior to the start-up of operations in 1978.

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, beginning January 1, 2010, Syncrude will begin transitioning to the new oil sands royalty regime by paying additional royalties, the exact amount of which will depend on production levels from 2010 to 2015. Also, beginning January 1, 2009, Syncrude s royalty will be based on bitumen value with upgrading costs and revenues excluded from the calculation.

The Government of Canada had issued an order that expired at the end of 2003, which provided for the remission of any federal income tax otherwise payable by the participants as the result of the non-deductibility from the income of the participants of amounts receivable by the Province of Alberta as a royalty or otherwise with respect to Syncrude. That remission order excluded royalty payable on production for the Aurora project. The final determination of the remission amount applicable to Syncrude operations up to 2003 is a matter currently being litigated with the Government of Canada.

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Operations at Syncrude involve three main processes: open pit mining, extraction of crude bitumen and upgrading of crude bitumen into synthetic crude oil. The Base mine (located on lease 17) was depleted and ceased operation in 2007. In the North mine (leases 17 and 22) and in the Aurora mine (leases 10, 12 and 34), truck, shovel and hydrotransport systems are used. The extraction facilities, which separate crude bitumen from sand, are capable of processing approximately 830,000 tons of oil sands a day, producing about 150 million barrels of crude bitumen a year. This represents recovery capability of about 93 percent of the crude bitumen contained in the mined oil sands.

Crude bitumen extracted from oil sands is refined to a marketable hydrocarbon product through a combination of carbon removal in three large, high temperature, fluid coking vessels and by hydrogen addition in high temperature, high pressure, hydrocracking vessels. These processes remove carbon and sulphur and reformulate the crude into a low viscosity, low sulphur, high quality synthetic crude oil product. In 2008, the upgrading process yielded 0.859 barrels of synthetic crude oil per barrel of crude bitumen. In 2008, about 39 percent of the synthetic crude oil was processed by Edmonton area refineries and the remaining 61 percent was pipelined to refineries in eastern Canada or exported to the United States. Electricity is provided to Syncrude by a 270 megawatt electricity generating plant and a 160 megawatt electricity generating plant, both located at Syncrude. The generating plants are owned by the Syncrude participants. Recycled water is the primary water source, and incremental raw water is drawn, under license, from the Athabasca River. The company s 25 percent share of net investment in plant, property and equipment, including surface mining facilities, transportation equipment and upgrading facilities is about $3.4 billion.

In 2008 Syncrude s net production of synthetic crude oil was about 246,800 barrels per day and gross production was about 288,900 barrels per day. The company s share of net production in 2008 was about 61,700 barrels per day.

In 2000, Syncrude completed development of the first stage of the Aurora mine. The Aurora investment involved extending mining operations to a new location about 22 miles from the main Syncrude site and expanding upgrading capacity. In 2001, the Syncrude owners approved another major expansion of upgrading capacity and further development of the Aurora mine. The second Aurora mining and extraction development became fully operational in 2004. The increased upgrading capacity came on stream in 2006. These projects increased total production capacity to about 355,000 barrels of synthetic crude oil a day. The company s share of total project costs was $2.1 billion. Additional mining trains in the North mine and Aurora mine were also completed in 2005. There are no approved plans for major future expansion projects.

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 and may be terminated with at least two years prior written notice.

The following table sets forth certain operating statistics for the Syncrude operations:

	2008	2007	2006	2005	2004
Total mined overburden (1)					
millions of cubic yards	**165.3**	132.2	128.2	97.1	100.3
Mined overburden to oil sands ratio (1)	**1.35**	1.06	1.18	1.02	0.94
Oil sands mined					
millions of tons	**216.4**	221.0	195.5	168.0	188.0
Average bitumen grade (weight percent)	**11.1**	11.6	11.4	11.1	11.1
Crude bitumen in mined oil sands					
millions of tons	**24.0**	25.6	22.2	18.6	20.9
Average extraction recovery (percent)	**90.3**	91.8	90.3	89.1	87.3
Crude bitumen production (2)					
millions of barrels	**122.5**	132.5	111.6	94.2	103.3
Average upgrading yield (percent)	**85.9**	84.3	84.9	85.3	85.5

Gross synthetic crude oil produced					
millions of barrels	**107.6**	113.0	95.5	79.3	88.4
Company s net share(3)					
millions of barrels	**22.6**	23.7	21.3	19.3	21.6

(1) Includes pre-stripping of mine areas and reclamation volumes.
(2) Crude bitumen production is equal to crude bitumen in mined oil sands multiplied by the average extraction recovery and the appropriate conversion factor.
(3) Reflects the company s 25 percent interest in production, less applicable royalties payable to the Province of Alberta.

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, established to recover shallow deposits of oil sands using open-pit mining methods to extract the crude bitumen. The Kearl project is located approximately 40

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miles north of Fort McMurray, Alberta and northeast of Syncrude Lease 31 (see map). The location is currently accessible by an existing road.

Kearl will be developed in three phases. Bitumen 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 heavy oil blend of bitumen and diluent, will 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 license in 2008, which permits the project to mine oil sands and produce bitumen from approved development areas on oil sands leases. Kearl is comprised of six oil sands leases covering about 48,000 acres in the Athabasca oil sands deposit. The leases, which are issued by the Province of Alberta, are automatically renewable as long as the oil sands operations are ongoing or the leases are part of an approved development plan. The leases involved in the first phase of the project are 6, 87 and 88A (which contain proven reserves) and 31A, 36, and 88B (which do not currently contain proven reserves). There were no known previous commercial operations on these leases.

Production from the first phase is expected to average approximately 110,000 barrels of bitumen a day, before royalties, of which the company s share would be about 78,000 barrels a day. About $500 million has been spent on the first phase. Activities in 2008 focused on engineering work to define the project design and execution plan. Other activities in 2008 also included access road construction, site preparation and earthworks. Significant progress has been made in transportation system agreements.

Kearl will be subject to the Alberta generic oil sands royalty regime, which was modified in 2007 and will take effect in 2009. Royalty rates will be based upon a sliding scale, determined by the price of crude oil.

Operations at Kearl will involve three main processes: open-pit mining, extraction of crude bitumen and diluent blending. The open-pit mining will utilize truck, shovel and hydrotransport systems. The extraction separates crude bitumen from sand through a froth processing plant. Electricity will be provided initially through the Alberta grid. Recycled water will be the primary water source, and incremental raw water will be drawn, under license, from the Athabasca River.

Other Oil Sands Activity

The company is continuing to evaluate about 69,000 net acres of other undeveloped oil sands acreage.

Land Holdings

At December 31, 2008 and 2007, the company held the following oil and gas rights, heavy oil and oil sands leases:

	Acres (1)					
	Developed		Undeveloped		Total	
	2008	**2007**	**2008**	**2007**	**2008**	**2007**
Western Provinces			(thousands)			
Conventional						
Gross (2)	**2,566**	2,529	**435**	371	**3,001**	2,900
Net (3)	**1,004**	995	**251**	223	**1,255**	1,218
Heavy Oil						
Gross (2)	**103**	102	**434**	429	**537**	531
Net (3)	**103**	102	**261**	258	**364**	360
Oil Sands						
Gross (2)	**114**	116	**315**	293	**429**	409
Net (3)	**29**	29	**137**	134	**166**	163
Canada Lands (4):						
Conventional						

Gross (2)	**37**	78	**1,343**	1,302	**1,380**	1,380
Net (3)	**5**	8	**499**	496	**504**	504
Atlantic Offshore						
Conventional						
Gross (2)	**65**	65	**6,012**	6,343	**6,077**	6,408
Net (3)	**6**	6	**1,308**	1,513	**1,314**	1,519
Total (5):						
Gross (2)	**2,885**	2,890	**8,539**	8,738	**11,424**	11,628
Net (3)	**1,147**	1,140	**2,456**	2,624	**3,603**	3,764

(1) Beginning in 2008, the company adopted the Alberta government standard for converting from hectares to acres for Alberta Crown lands.
(2) Gross acres include the interests of others.
(3) Net acres exclude the interests of others.
(4) Canada Lands include the Arctic Islands, Beaufort Sea/Mackenzie Delta, and other Northwest Territories, Nunavut and Yukon regions.
(5) 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).

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Exploration and Development

The company has been involved in the exploration for and development of petroleum and natural gas in the Western Provinces, in the Canada Lands and in the Atlantic Offshore.

The following table sets forth the conventional and heavy oil net exploratory and development wells that were drilled or participated in by the company during the five years ending December 31, 2008.

	2008	**2007**	**2006**	**2005**	**2004**
Western and Atlantic Provinces:					
Conventional					
Exploratory					
Oil					
Gas			1		2
Dry Holes					1
Development					
Oil	**1**			2	3
Gas	**146**	183	192	155	207
Dry Holes			1	1	1
Heavy Oil (Cold Lake and other)					
Development					
Oil	**70**	188	174	87	218
Total	**217**	371	368	245	432

Weather related delays in 2005 resulted in a reduction in the number of wells drilled in the ongoing shallow gas development program. In 2007, 188 heavy oil development wells were drilled to add new productive capacity from undeveloped areas of existing phases at Cold Lake. In addition, 183 gas development wells were drilled in 2007 adding productivity primarily in the shallow gas area. In 2008, 70 heavy oil 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.

At December 31, 2008, the company was participating in the drilling of 295 gross (172 net) exploratory and development wells.

Western Provinces

In 2008, the company had a working interest in 526 gross (338 net) development wells. In 2007 and 2008, the company acquired interest in about 76,000 net acres in the natural gas prone Horn River area and commenced exploration drilling and evaluation of the Horn River acreage in late 2008. The company s exploration strategy in other areas of the Western Provinces is to search for hydrocarbons on its existing land holdings especially near established facilities.

Beaufort Sea/Mackenzie Delta

Substantial quantities of gas have been found by the company and others in the Beaufort Sea/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 regulatory process continues with a JRP report expected in late 2009 followed by an NEB decision in 2010.

In 2007, the company acquired a 50 percent interest in an exploration licence for about 507,000 gross acres in the Beaufort Sea. As part of the evaluation, a 3-D seismic survey was conducted in 2008.

Other land holdings include majority interests in 20, 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.

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Arctic Islands

The company has an interest in 16 Significant Discovery Licences and one production licence granted by the Government of Canada in the Arctic Islands. These licences are managed by another company on behalf of all participants. The company has not participated in wells drilled in this area since 1984.

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 in 27 Significant Discovery Licences, and six production licences, managed by others.

In 2008, one exploration licence in the Sable Island area, in which the company had a 20 percent interest, for about 52,000 gross acres was allowed to expire. Also in 2008, one exploration licence in which the company had a 70 percent interest for about 279,000 gross acres farther offshore in deeper water was allowed to expire. The company is not planning further exploration in these areas.

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 2004 and 2005, the company participated in 3-D seismic surveys in this area. Drilling of an exploration well was concluded in early 2007. 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 4,200,000 gross acres. The company s share of proposed exploration spending is about $60 million with a minimum commitment of about $15 million. Additional drilling is planned.

The company retains 100 percent interest in a single exploration licence for about 474,000 gross acres in the Laurentian basin area offshore Newfoundland and Labrador, which is scheduled to be allowed to expire in April 2009.

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. Two of these, the Sarnia refinery and the Strathcona refinery, have 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 2008, capital expenditures of about $150 million were made at the company s refineries. About 60 percent of those expenditures were on environmental and safety initiatives with the remaining expenditures being primarily on capacity and efficiency improvements.

The approximate average daily volumes of refinery throughput during the five years ended December 31, 2008, and the daily rated capacities of the refineries at December 31, 2003 and 2008, were as follows:

	Average Daily Volumes of Refinery Throughput (1) Year Ended December 31					Daily Rated Capacities at December 31 (2)	
	2008	**2007**	**2006**	**2005**	**2004**	**2008**	**2003**
	(thousands of barrels)						
Strathcona, Alberta	**155**	170	160	174	170	187	187
Sarnia, Ontario	**108**	103	111	106	108	121	121
Dartmouth, Nova Scotia	**76**	69	77	79	80	82	82
Nanticoke, Ontario	**107**	100	94	108	109	112	112
Total	**446**	442	442	466	467	502	502

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

(2) 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 89 percent of capacity in 2008, one percent higher than the previous year. Production gains from reliability improvements through the year were partially offset by the impact of declining economic conditions that did not support running the refineries to full capacity.

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Distribution

The company maintains a nation-wide distribution system, including 25 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 crude oil, natural gas liquids and products pipelines in Alberta, Manitoba and Ontario and has interests in the capital stock of two products and two crude oil pipeline companies.

Marketing

The company markets more than 700 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 1,900 sites, of which about 570 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 90 sales facilities. Heating oil is provided through authorized dealers, as well as through a company operated Home Comfort facility serving the Montreal urban market. 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, 2008, are set out in the following table:

	2008	**2007**	**2006**	**2005**	**2004**
			(thousands of barrels a day)		
Gasolines	**204**	208	206	210	209
Heating, Diesel and Jet Fuels	**157**	164	166	169	172
Heavy Fuel Oils	**30**	33	32	38	37
Lube Oils and Other Products	**47**	43	49	48	44
Net petroleum product sales	**438**	448	453	465	462

The total domestic sales of petroleum products, as a percentage of total sales of petroleum products during the five years ended December 31, 2008, were as follows:

2008	**2007**	**2006**	**2005**	**2004**
93.0%	94.8%	95.1%	95.3%	93.0%

The company continues to evaluate and adjust its Esso retail service station and distribution system to increase productivity and efficiency. During 2008, the company closed or debranded about 85 Esso retail service stations, about 20 of which were company owned, and added about 45 sites. The company s average annual throughput in 2008 per Esso retail service station was 24 thousand barrels (3.8 million litres) the same as 2007. Average throughput per company owned or leased Esso retail service station was 42 thousand barrels (6.7 million litres) in 2008, an increase of about one thousand barrels (0.2 million litres) from 2007.

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 average daily sales of petrochemicals during the five years ended December 31, 2008, were as follows:

	2008	2007	2006	2005	2004
	(thousands of tonnes a day)				
Petrochemicals	**2.8**	3.1	3.0	3.0	3.3

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Research

In 2008, the company s research expenditures in Canada, before deduction of investment tax credits, were $117 million, as compared with $83 million in 2007, and $56 million in 2006. Those funds were used mainly for developing improved heavy oil and oil sands recovery methods and better lubricants.

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 2008. The company also participated in heavy oil 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. About 105 people were employed in this type of research and advanced technical support at the end of 2008. Also in Sarnia, there are about 10 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 and industry associations to deal with existing, and to anticipate potential, environmental protection issues. In the past five years, the company has made capital and other expenditures of about $2.6 billion on environmental protection and facilities. The environmental expenditures over the past five years primarily reflect spending on two major projects. One project completed in 2004, costing about $650 million, reduced sulphur in motor gasolines, meeting a requirement of the Government of Canada. The second project completed in 2006 was to meet a new Government of Canada regulation requiring ultra-low sulphur on-road diesel fuel, which cost about $500 million in total. In 2008, the company s capital and other expenditures relating to environmental protection totaled approximately $620 million, which was spent primarily on emissions reductions at Syncrude and company owned facilities, remediation of idled facilities and operations, as well as on ultra-low sulphur off-road diesel fuel. Capital and other expenditures relating to environmental protection are expected to be about $750 million in 2009.

Human Resources

At December 31, 2008, the company employed full-time approximately 4,850 persons, compared with about 4,800, at the end of 2007 and 4,900 at the end of 2006. 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.

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.

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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 2008 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 Petroleum and Natural Gas Production .

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 to be 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. 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. These reports are made available as soon as reasonably practicable after they are filed or furnished to the U.S. Securities and Exchange Commission.

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

The company does not use derivative investments to speculate on the future direction of commodity prices.

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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.

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.

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. 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. Compliance costs were not material in 2007 and 2008, and the company does not expect ongoing compliance costs to have a material adverse effect on the company s operations or financial condition.

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. This may have implications for the company s marketing in the United States of some heavy oil and oil sands production, but the impact cannot be determined at this time.

Further federal or provincial legislation or regulation controlling greenhouse gas emissions could occur and result in increased capital expenditures and operating costs, which could 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 conventional oil, heavy 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.

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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 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 its 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.

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.

Market Risk Factors

During 2008, credit markets tightened, and the global economy slowed. In 2009, the company does not expect to be dependent on credit markets to fund normal operations or investment plans.

Item 1B Unresolved Staff Comments.
Not applicable.

Item 2. Properties.
Reference is made to Item 1 above, and for the reserves of the Syncrude mining operations, Kearl project and oil and gas producing activities, reference is made to Item 8 of this report.

Item 3. Legal Proceedings.
Not applicable.

Item 4. Submission of Matters to a Vote of Security Holders.
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.

Information for Security Holders Outside Canada

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

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

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

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

Quarterly Financial and Stock Trading Data

	2008				2007			
	Three months ended				Three months ended			
	Mar. 31	Jun. 30	Sep. 30	Dec. 31	Mar. 31	Jun. 30	Sep. 30	Dec. 31
Financial data	(millions of dollars)				(millions of dollars)			
Total revenues and other income	**7,263**	**8,859**	**9,515**	**5,942**	5,934	6,339	6,430	6,740
Total expenses	**6,298**	**7,276**	**7,558**	**5,171**	4,819	5,319	5,240	5,686
Income before income taxes	**965**	**1,583**	**1,957**	**771**	1,115	1,020	1,190	1,054
Income taxes	**284**	**435**	**568**	**111**	(341)	(308)	(374)	(168)
Net income	**681**	**1,148**	**1,389**	**660**	774	712	816	886
Per-share information	(dollars)				(dollars)			
Net earnings basic	**0.76**	**1.29**	**1.57**	**0.77**	0.82	0.76	0.88	0.97
Net earnings diluted	**0.75**	**1.28**	**1.57**	**0.76**	0.81	0.76	0.88	0.96
Dividends (declared quarterly)	**0.09**	**0.09**	**0.10**	**0.10**	0.08	0.09	0.09	0.09
Share prices (1)	(dollars)				(dollars)			
Toronto Stock Exchange								
High	**58.09**	**62.54**	**57.80**	**46.43**	43.75	54.70	51.90	56.26
Low	**45.80**	**52.41**	**41.60**	**28.79**	37.40	41.77	40.86	45.57
Close	**53.80**	**56.16**	**45.58**	**40.99**	42.80	49.59	49.29	54.62
NYSE Alternext	($U.S.)				($U.S.)			
High	**58.91**	**63.08**	**56.89**	**43.66**	38.29	50.35	50.95	61.48
Low	**44.30**	**51.24**	**40.00**	**23.84**	31.87	36.90	37.99	46.43
Close	**52.26**	**55.07**	**42.60**	**33.72**	37.12	46.34	49.56	54.78

(1) The company s shares are listed on the Toronto Stock Exchange. The company s shares also trade in the United States of America on the NYSE Alternext, formerly known as the American Stock Exchange. The symbol on these exchanges for the company s common shares is IMO. Share prices were obtained from stock exchange records. U.S. dollar share price presented is based on consolidated U.S. market data.

As of February 13, 2009 there were 13,242 holders of record of common shares of the company.

During the period October 1, 2008 to December 31, 2008, the company issued 33,600 common shares to employees or former employees outside the U.S.A. for $15.50 per share upon the exercise of stock options. These issuances were not registered under the *Securities Act* in reliance on Regulation S thereunder.

On June 23, 2008, 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 44,194,961 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, 2008 to June 24, 2009. If not previously terminated, the program will end on June 24, 2009.

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Issuer purchases of equity securities

Period	(a) Total number of shares purchased	(b) Average price paid per share ($)	(c) Total number of shares purchased as part of publicly announced plans or programs	(d) Maximum number (or approximate dollar value) of shares that may yet be purchased under the plans or programs
October 2008 (October 1 - October 31)	1,365,130	40.95	1,365,130	28,973,635
November 2008 (November 1 - November 30)	5,380,001	37.94	5,380,001	23,511,797
December 2008 (December 1 - December 31)	3,559,812	40.13	3,559,812	19,875,171

Item 6. Selected Financial Data.

	2008	2007	2006	2005	2004
			(millions of dollars)		
Operating revenues (1)	**31,240**	25,069	24,505	27,797	22,408
Net income	**3,878**	3,188	3,044	2,600	2,052
Total assets at year end	**17,035**	16,287	16,141	15,582	14,027
Long term debt at year end	**34**	38	359	863	367
Total debt at year end	**143**	146	1,437	1,439	1,443
Other long term obligations at year end	**2,298**	1,914	1,683	1,728	1,525
			(dollars)		
Net income/share basic (2)	**4.39**	3.43	3.12	2.54	1.92
Net income/share diluted (2)	**4.36**	3.41	3.11	2.53	1.91
Cash dividends/share (2)	**0.38**	0.35	0.32	0.31	0.29

(1) Operating revenues include $4,894 million for 2005 and $3,584 million for 2004 for purchases/sales contracts with the same counterparty. Associated costs were included in purchases of crude oil and products . Effective January 1, 2006, these purchases/sales were recorded on a net basis.

(2) Adjusted to reflect the May 2006 three-for-one share split.

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.

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

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primary energy at an average rate of 1.2 percent annually. The vast majority of this increase is expected to occur in developing countries.

Oil, gas and coal are expected to remain the predominant energy sources with approximately 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 two percent per year, and Canadian demand for energy at about half of one 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. Primarily because of increased demand in developing countries, oil consumption is expected to increase by about 25 percent or over 20 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 35 percent of all incremental energy growth and approaching 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.

Upstream

Imperial produces crude oil and natural gas for sale into large 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. In the past, crude oil and natural gas prices have been volatile, and the company expects that volatility to continue.

Imperial s fundamental Upstream business strategies guide our exploration, development, production 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 our employees and investment in the communities in which we operate.

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

Downstream

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

Imperial s Downstream strategies are to provide customers with quality service and products at the lowest total cost offer, have the lowest unit costs among our competitors, ensure efficient and effective use of capital and capitalize on integration with the company s other businesses. Imperial owns and operates four refineries in Canada, with distillation capacity of 502,000 barrels a day and lubricant manufacturing capacity of 8,000 barrels a day.

Imperial s fuels marketing business includes retail operations across Canada serving customers through about 1,900 Esso-branded retail service stations, of which about 570 are company-owned or leased, and wholesale and industrial operations through a network of 24 primary distribution terminals, as well as a secondary distribution network.

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Chemical

The North American petrochemical industry is cyclical. 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

Net income in 2008 of $3,878 million or $4.36 a share on a diluted basis was the best on record, exceeding the previous record achieved in 2007 of $3,188 million or $3.41 a share. Earnings increased primarily due to higher crude oil and natural gas commodity prices. Improved upstream realizations were partially offset by the negative impacts of lower upstream volumes, higher royalties, higher energy and maintenance costs and lower overall downstream margins.

Upstream

Net income was $2,923 million versus $2,369 million in 2007. Earnings benefited from higher overall crude oil and natural gas commodity prices totaling about $2,100 million. Their positive impact on earnings was partially offset by lower conventional volumes from expected reservoir decline of about $420 million, lower Syncrude volumes of about $135 million and lower cyclical Cold Lake heavy oil production of about $105 million. Earnings were also negatively impacted by higher royalties of about $310 million, higher energy, Syncrude maintenance, and other production costs totaling about $290 million, the absence of favourable effects of tax rate changes of about $170 million and lower gains from asset divestments of about $140 million.

Financial statistics

	2008	**2007**	**2006**	**2005**	**2004**
			(millions of dollars)		
Net income	**2,923**	2,369	2,376	2,008	1,517
Operating revenues	**11,222**	8,685	8,456	8,189	6,580

World crude oil prices ended in 2008 much lower than the record levels reached earlier in the year. The price of Brent crude oil, a common benchmark of world oil markets, declined from a high of $144.22 (U.S.) a barrel in July to a low of $33.65 (U.S.) in December. For the year, the average price of Brent crude oil was $96.99 (U.S.) a barrel, up about 34 percent from 2007. The company s realizations on sales of Canadian conventional crude oil mirrored the same trends as world prices, ending 2008 at a level much lower than the average of the year.

Prices for Canadian heavy oil, including the company s heavy oil at Cold Lake, moved generally in line with that of the lighter crude oil. The price of Bow River, a benchmark for Canadian heavy oil, increased by about 56 percent in 2008 from 2007 and fell much below the year s average by the end of the year.

Prices for Canadian natural gas in 2008 were higher than in the previous year. The average of 30-day spot prices for natural gas in Alberta was about $8.61 a thousand cubic feet in 2008, compared with $7.01 in 2007 (2006 $7.41). The company s average realizations on natural gas sales were $8.69 a thousand cubic feet, compared with $6.95 in 2007 (2006 $7.24).

Average realizations and prices

	2008	2007	2006	2005	2004
			(Canadian dollars)		
Conventional crude oil realizations (a barrel)	**95.76**	71.70	68.58	64.48	48.96
Natural gas liquids realizations (a barrel)	**59.35**	47.92	40.75	40.00	33.78
Natural gas realizations (a thousand cubic feet)	**8.69**	6.95	7.24	9.00	6.78
Par crude oil price at Edmonton (a barrel)	**103.60**	77.67	73.75	69.86	53.26

Heavy oil price at Hardisty (Bow River, a barrel)	**83.91**	53.87	51.90	45.62	37.98

Gross production of heavy oil at the company s wholly owned facilities at Cold Lake was 147,000 barrels a day, compared with 154,000 barrels in 2007 (2006 152,000). Lower production was due to the cyclic nature of production at Cold Lake.

Gross production of synthetic crude oil from the Syncrude oil sands operation, in which the company has a 25 percent interest, was 289,000 barrels a day versus 305,000 barrels in 2007 (2006 258,000). Lower volumes were primarily the result of planned and unplanned maintenance activities during the year, including work to improve reliability performance. Imperial s share of average gross production decreased to 72,000 barrels a day from 76,000 barrels in 2007 (2006 65,000).

Gross production of conventional oil decreased to 27,000 barrels a day from 29,000 barrels in 2007 (2006 31,000) as a result of natural decline in Western Canadian reservoirs.

Gross production of natural gas decreased to 310 million cubic feet a day from 458 million in 2007 (2006 556 million). The most significant reason for the lower production volumes was the completion of production, as expected, from the Wizard Lake gas cap blowdown.

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Gross production of natural gas liquids (NGLs) available for sale averaged 10,000 barrels a day in 2008, down from 16,000 barrels in 2007 (2006 24,000), mainly due to the completion of production from Wizard Lake.

Crude oil and NGLs - production and sales (1)

	2008		2007		2006		2005		2004	
	gross	net	gross	net	gross	net	gross	net	gross	net
	(thousands of barrels a day)									
Cold Lake	**147**	**124**	154	130	152	127	139	124	126	112
Syncrude	**72**	**62**	76	65	65	58	53	53	60	59
Conventional crude oil	**27**	**19**	29	21	31	23	38	29	43	33
Total crude oil production	**246**	**205**	259	216	248	208	230	206	229	204
NGLs available for sale	**10**	**8**	16	12	24	19	31	25	33	26
Total crude oil and NGL production	**256**	**213**	275	228	272	227	261	231	262	230
Cold Lake sales, including diluent (2)	**191**		200		198		183		167	
NGL sales	**11**		20		29		39		42	

Natural gas - production and sales (1)

	2008		2007		2006		2005		2004	
	gross	net	gross	net	gross	net	gross	net	gross	net
	(millions of cubic feet a day)									
Production (3)	**310**	**249**	458	404	556	496	580	514	569	518
Sales	**288**		407		513		536		520	

(1) 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.
(2) Diluent is natural gas condensate or other light hydrocarbons added to Cold Lake heavy oil to facilitate transportation to market by pipeline.
(3) Production of natural gas includes amounts used for internal consumption with the exception of the amounts reinjected.

Production costs increased mainly due to higher energy prices and Syncrude maintenance costs.

Downstream

Net income was $796 million, compared with $921 million in 2007. Earnings decreased primarily due to lower overall downstream margins and unfavourable inventory effects totaling about $230 million. Earnings were also lower due to higher planned maintenance costs of about $40 million and lower sales volumes of about $40 million. These factors were partially offset by a gain of $187 million from the sale of the company s equity investment in Rainbow Pipe Line Co. Ltd.

Financial statistics

	2008	2007	2006	2005	2004
	(millions of dollars)				
Net income	**796**	921	624	694	556
Operating revenues (1)	**26,941**	21,535	20,783	24,017	19,169

Sale of petroleum products

	2008	2007	2006	2005	2004
			(thousands of barrels a day (2))		
Gasolines	**204**	208	206	210	209
Heating, diesel and jet fuels	**157**	164	166	169	172
Heavy fuel oils	**30**	33	32	38	37
Lube oils and other products	**47**	43	49	48	44
Net petroleum product sales	**438**	448	453	465	462
Total domestic sales of petroleum products (percent)	**93.0**	94.8	95.1	95.3	93.0

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Refinery utilization

	2008	2007	2006	2005	2004
			(thousands of barrels a day (2))		
Total refinery throughput (3)	**446**	442	442	466	467
Refinery capacity at December 31	**502**	502	502	502	502
Utilization of total refinery capacity (percent)	**89**	88	88	93	93

(1) Operating revenues in 2005 and prior years included amounts for purchases/sales with the same counterparty. Associated costs were included in purchases of crude oil and products . Effective January 1, 2006, these purchases/sales were recorded on a net basis.
(2) Volumes a day are calculated by dividing total volumes for the year by the number of days in the year.
(3) Crude oil and feedstocks sent directly to atmospheric distillation units.

Industry refining margins were lower in 2008, compared with those in 2007, reflecting weakening demand and higher inventory levels. Marketing margins in 2008 were higher than those in 2007.

Refinery throughput was 89 percent of capacity in 2008, one percent higher than the previous year (2006 - 88 percent). Reliability improvements through the year were partially offset by the impact of declining economic conditions that did not support running the refineries to full capacity.

Downstream s total sales volumes, excluding those resulting from purchases/sales contracts with the same counterparty, were 438,000 barrels a day, down from 448,000 barrels in 2007 (2006 453,000). Lower industry demand was the main reason for the decline.

Manufacturing costs in 2008 were higher than the previous year primarily reflecting higher energy prices and planned maintenance costs.

Chemical

Net income was $100 million, compared with $97 million in 2007. Higher margins for polyethylene products were essentially offset by lower margins for intermediate products and lower sales volumes for both polyethylene and intermediate products.

Financial statistics

	2008	2007	2006	2005	2004
			(millions of dollars)		
Net income	**100**	97	143	121	109
Operating revenues	**1,832**	1,635	1,704	1,665	1,509

Sales

	2008	2007	2006	2005	2004
			(thousands of tonnes a day (1))		
Polymers and basic chemicals	**2.1**	2.2	2.2	2.1	2.4
Intermediate and others	**0.7**	0.9	0.8	0.9	0.9
Total petrochemicals	**2.8**	3.1	3.0	3.0	3.3

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

The average industry price of polyethylene was $1,960 a tonne in 2008, up 18 percent from $1,666 a tonne in 2007 (2006 $1,703), contributing to higher margins for polyethylene products.

Sales of chemical products were 2,800 tonnes a day, down from 3,100 tonnes in 2007 (2006 3,000 tonnes), primarily due to lower industry demand for both polyethylene and intermediate chemical products.

Manufacturing costs for 2008 were higher than 2007, reflecting higher energy prices.

Corporate and other

Net income effects from corporate and other were $59 million, versus negative $199 million last year. Favourable earnings effects were primarily due to lower share-based compensation charges and the absence of unfavourable effects of tax rate changes reported in 2007.

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Liquidity and capital resources

Sources and uses of cash

	2008	2007 (millions of dollars)	2006
Cash provided by/(used in)			
Operating activities	**4,263**	3,626	3,587
Investing activities	**(961)**	(620)	(965)
Financing activities	**(2,536)**	(3,956)	(2,125)
Increase/(decrease) in cash and cash equivalents	**766**	(950)	497
Cash and cash equivalents at end of year	**1,974**	1,208	2,158

Although the company issues long-term debt from time to time and maintains a revolving commercial paper program, internally generated funds normally 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 and to optimize returns on cash balances.

Cash flows from operating activities are highly dependent on crude oil and natural gas prices and product margins. In addition, to support cash flows in future periods, the company will need to continually find and develop new fields, 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 of the company and associated cash flow. 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.

The company s registered pension plan is subject to an independent actuarial valuation that is required at least once every three years. The next such valuation will take place in 2010. Given the recent downturn in financial markets, the next valuation could require that Imperial increase its contributions to the plan over the next five years. The size of any required contribution will not be known until the valuation is completed. The company expects that it will meet any funding requirements without affecting current or future investment plans.

Cash flow from operating activities

Cash provided by operating activities was $4,263 million, versus $3,626 million in 2007 (2006 $3,587 million). Higher cash flow in 2008 was primarily due to higher net income.

Cash flow from investing activities

Cash used in investing activities totaled $961 million in 2008, compared with $620 million in 2007 (2006 - $965 million). Higher spending on property, plant and equipment contributed to the increase.

Capital and exploration expenditures

Total capital and exploration expenditures were $1,363 million in 2008, compared with $978 million in 2007 (2006 $1,209 million).

The funds were used mainly to advance the Kearl oil sands project, maintain Cold Lake production capacity, invest in environmental initiatives and upgrade the network of Esso retail outlets. About $250 million was spent on projects related to reducing the environmental impact of the company s operations and improving safety.

The following table shows the company s capital and exploration expenditures for Upstream during the five years ending December 31, 2008:

	2008	2007	2006	2005	2004
			(millions of dollars)		
Heavy oil and oil sands	**740**	489	518	662	819
Production	**238**	150	237	232	234
Exploration	**132**	105	32	43	60
Total capital and exploration expenditures	**1,110**	744	787	937	1,113

For the Upstream segment, over 85 percent of the capital and exploration expenditures in 2008 were focused on growth opportunities. Significant expenditures during the year were for advancing the Kearl oil sands project and ongoing development drilling at Cold Lake. Other 2008 investments included facilities improvements at Syncrude, drilling at Horn River and conventional fields in Western Canada and a 3-D seismic program in the Beaufort Sea.

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Kearl is an oil sands mining project located northeast of Fort McMurray, Alberta. Regulatory approvals were received and the project is planned to advance in phases. Production from the first phase of Kearl is expected to average approximately 110,000 barrels of bitumen a day before royalties, of which Imperial s share would be about 78,000 barrels. Imperial s share of proven reserves developed by the first phase is 807 million barrels and was added to the company s proven mined bitumen reserves in 2008.

About $500 million had been invested in Kearl by the end of 2008. Activities in 2008 focused on engineering work to define the project design and execution plan. Other activities in 2008 also included access road construction, site preparation and earthworks. Significant progress has also been made in transportation system agreements.

Imperial has acquired exploration licenses to about 76,000 net acres in British Columbia s natural gas prone Horn River area. Exploration drilling and evaluation commenced in 2008.

Planned capital and exploration expenditures in the Upstream segment are expected to be about $1.8 billion in 2009, with over 80 percent of the total focused on growth opportunities. Investments are mainly planned for the Kearl oil sands project and development drilling at Cold Lake. Other investments will include facilities improvements at Syncrude, development drilling at conventional oil and gas operations in Western Canada and exploration at Horn River.

The following table shows the company s capital expenditures in the Downstream segment during the five years ending December 31, 2008:

	2008	2007	2006	2005	2004
			(millions of dollars)		
Refining and supply	**160**	120	248	368	178
Marketing	**61**	63	97	91	85
Other (1)	**11**	4	16	19	20
Total capital expenditures	**232**	187	361	478	283

(1) Consists primarily of real estate purchases.

For the Downstream segment, capital expenditures were $232 million in 2008, compared with $187 million in 2007 (2006 $361 million). In 2008, Downstream capital expenditures focused mainly on improving air emissions, increasing refinery capacity utilization and upgrading the retail network.

Capital expenditures for the Downstream segment in 2009 are expected to be about $400 million, and will be mainly directed to increasing sulphur recovery to further reduce sulphur dioxide emissions, upgrading water management systems as well as enhancing feedstock flexibility and energy efficiency. Retail projects will continue to focus on network upgrades in major urban markets.

The following table shows the company s capital expenditures for its Chemical operations during the five years ending December 31, 2008:

	2008	2007	2006	2005	2004
			(millions of dollars)		
Capital expenditures	13	11	13	19	15

Of the capital expenditures for the Chemical segment in 2008, the major investment was directed to upgrading water management systems, improving safety and increasing feedstock flexibility.

Planned capital expenditures for Chemical in 2009 is about $35 million and will include continued investments to increase feedstock flexibility and further upgrade water management and safety systems.

Total capital and exploration expenditures for the company in 2009, which will focus mainly on growth and productivity improvements, are expected to total about $2.2 billion and to be financed from internally generated funds.

Cash flow from financing activities

Cash used in financing activities was $2,536 million in 2008, compared with $3,956 million in 2007 (2006 - $2,125 million).

In June, another 12 month share repurchase program was implemented. During 2008, the company purchased 44.3 million shares for $2,210 million (2007 50.5 million shares for $2,358 million), including shares purchased from ExxonMobil. Since Imperial initiated its first share repurchase program in 1995, the company has purchased 890.4 million shares representing about 51 percent of the total outstanding at the start of the program with resulting distributions to shareholders of over $15 billion.

The company declared dividends totaling 38 cents a share in 2008, up from 35 cents in 2007 (2006 32 cents). Regular annual per-share dividends paid have increased in each of the past 14 years and, since 1986, payments per share have grown by 102 percent.

Total debt outstanding at the end of 2008, excluding the company s share of equity company debt, was $143 million, compared with $146 million at the end of 2007 (2006 $1,437 million). Debt represented two percent of the company s capital structure at the end of 2008, unchanged from the end of 2007 (2006 17 percent).

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Debt-related interest incurred in 2008, before capitalization of interest, was $8 million, compared with $62 million in 2007 (2006 $63 million). The average effective interest rate on the company s debt was 5.5 percent in 2008, compared with 4.9 percent in 2007 (2006 4.4 percent).

Financial percentages and ratios

	2008	2007	2006	2005	2004
Total debt as a percentage of capital (1)	**2**	2	17	18	19
Interest coverage ratios					
Earnings basis (2)	**661**	72	66	88	83
Cash-flow basis (3)	**721**	82	77	101	108

(1) Current and long-term portions of debt (page F-4) and the company s share of equity company debt, divided by debt and shareholders equity (page F-4).
(2) Net income (page F-3), debt-related interest before capitalization (page F-19, note 13) and income taxes (page F-3), divided by debt-related interest before capitalization.
(3) Cash flow from net income adjusted for other non-cash items (page F-6), current income tax expense (page F-11, note 4) and debt-related interest before capitalization (page F-19, note 13) divided by debt-related interest before capitalization.

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.

Commitments

The following table shows the company s commitments outstanding at December 31, 2008. It combines data from the consolidated balance sheet and from individual notes to the consolidated financial statements.

	Financial Statement note reference	**Payment due by period**			
		2009	**2010 to 2013**	**2014 and beyond**	**Total amount**
			(millions of dollars)		
Capitalized lease obligations (1)	Note 14	4	15	19	38
Operating leases (2)	Note 14	64	210	158	432
Unconditional purchase obligations (3)	Note 10	127	262	31	420
Firm capital commitments (4)		251	80	-	331
Pension and other post-retirement obligations (5)	Note 5	253	203	740	1,196
Asset retirement obligations (6)	Note 6	42	309	360	711
Other long-term purchase agreements (7)		302	506	166	974

(1) Capital lease obligations primarily relate to the capital lease for marine services.
(2) Minimum commitments for operating leases, shown on an undiscounted basis, primarily cover office buildings, rail cars and service stations.
(3) Unconditional purchase obligations are those long-term commitments that are non-cancelable 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.
(4)

Firm capital commitments related to capital projects, shown on an undiscounted basis. The largest commitments outstanding at year-end 2008 were $98 million associated with the company s share of exploration projects.

(5) 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 2009 and estimated benefit payments for unfunded plans in all years.

(6) Asset retirement obligations represent the fair value of legal obligations associated with site restoration on the retirement of assets with determinable useful lives.

(7) 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 $150 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 F-11.

The company was contingently liable at December 31, 2008, for a maximum of $79 million relating to guarantees for purchasing operating equipment and other assets from its rural marketing associates upon expiry of the associate agreement or the resignation of the associate. The company expects that the fair value of the operating equipment and other assets so purchased would cover the maximum potential amount of future payments under the guarantees.

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Litigation and other contingencies

As discussed in note 10 to the consolidated financial statements on page F-18, 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 or financial condition.

The Alberta government enacted changes to the oil and gas and generic oil sands royalty regime effective 2009. The impacts of the changes have been incorporated in the company s 2008 oil and gas reserves and mined bitumen reserves calculation, where appropriate. 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, beginning January 1, 2010, Syncrude will begin transitioning to the new oil sands royalty regime by paying additional royalties, the exact amount of which will depend on production levels from 2010 to 2015. Also, beginning January 1, 2009, Syncrude s royalty will be based on bitumen value with upgrading costs and revenues excluded from the calculation. The impacts of the amended agreement have been incorporated in the 2008 synthetic crude oil reserves calculation.

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 F-7.

Hydrocarbon reserves

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

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

The year-end oil and gas reserves volumes as well as the reserves change categories shown in the proved reserves tables are calculated using December 31 prices and costs. These reserves quantities are also used in calculating unit-of-production depreciation rates and in calculating the standardized measure of discounted net cash flow. We understand that the use of December 31 prices and costs is intended to provide a point in time measure to calculate reserves and to enhance comparability between companies. However, the use of year-end prices for reserves estimation introduces short-term price volatility into the process, which is inconsistent with the long-term nature of the upstream business, since annual adjustments are required based on prices occurring on a single day. As a result, the use of prices from a single date is not relevant to the investment decisions made by the company.

Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the evaluation or revaluation of already available geologic, reservoir or production data; new geologic, reservoir or production data; or changes in year-end prices and costs that are used in the determination of reserves. This category can also include significant changes in either development strategy or production equipment/facility capacity. The quantities shown in the revisions category under heavy oil proved reserves in 2006 on page 31 were due mainly to the changes in year-end prices and costs that were used in the determination of reserves. 807 million barrels of mined bitumen reserves were added in 2008, reflecting the company s share of reserves being developed in the first phase of the Kearl oil sands project.

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

Impact of reserves on depreciation

The calculation of unit-of-production depreciation is a critical accounting estimate that measures the depreciation of 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 proved reserves. Where probable reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the impairment evaluation. An asset would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount by which the asset s carrying value exceeds its fair value.

The 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 current 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.

The standardized measure of discounted future cash flows on page 32 is based on the year-end price applied for all future years, as required under Statement of Financial Accounting Standards No. 69 (SFAS 69). Future prices used for any impairment tests will vary from the one used in the SFAS 69 disclosure and could be lower or higher for any given year.

Pension benefits

The company s pension plan is managed in compliance with the requirements of governmental authorities and meets funding levels as determined by independent third-party actuaries. Pension accounting requires explicit assumptions regarding, among others, the discount rate for the benefit obligations, the expected rate of return on plan assets and the long-term rate of future compensation increases. All pension assumptions are reviewed annually by senior management. These assumptions are adjusted only as appropriate to reflect long-term changes in market rates and outlook. The long-term expected rate of return on plan assets of 8.00 percent used in 2008 compares to actual returns of 5.00 percent and 8.31 percent achieved over the last 10- and 20-year periods ending December 31, 2008. 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 F-12. 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. Pension expense represented less than one percent of total expenses in 2008.

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

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measured at fair value and discounted to present value. Over time, the discounted asset retirement obligation amount will be accreted for the change in its present value, with this effect included in operating expense. As payments to settle the obligations occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 25 years, the discount rate will be adjusted only as appropriate to reflect long-term changes in market rates and outlook. For 2008, the obligations were discounted at six percent and the accretion expense was $29 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 F-11.

Item 7A. Quantitative and Qualitative Disclosures about Market Risks.

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

During 2008, credit markets tightened, and the global economy slowed. In 2009, the company does not expect to be dependent on credit markets to fund normal operations or investment plans.

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. 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. Compliance costs were not material in 2007 and 2008, and the company does not expect ongoing compliance costs to have a material adverse effect on the company s operations or financial condition.

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. This may have implications for the company s marketing in the United States of some heavy oil and oil sands production, but the impact cannot be determined at this time.

Other risks, such as changes in international commodity prices and currency-exchange rates, are beyond the company s control. The company does not use derivative markets to speculate on the future direction of currency or commodity prices. The company s size, strong financial position and the complementary nature of its Upstream, Downstream and Chemical segments help mitigate the company s exposure to changes in these other risks. The company s potential exposure to these types of risk is summarized in the earnings sensitivities table below, which shows the estimated annual effect, under current conditions, of certain sensitivities of the company s after-tax net income.

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Earnings sensitivities (1)

		millions of dollars after tax
Three dollars (U.S.) a barrel change in crude oil prices	+ (-)	150
Seventy cents a thousand cubic feet change in natural gas prices	+ (-)	6
One dollar (U.S) a barrel change in sales margins for total petroleum products	+ (-)	140
One cent (U.S.) a pound change in sales margins for polyethylene	+ (-)	7
Eight cents decrease (increase) in the value of the Canadian dollar versus the U.S. dollar	+ (-)	300

(1) 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 2008. 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 crude oil prices increased from 2007 year-end by about $13 million (after-tax) for each one U.S.-dollar a barrel difference. A decrease in the value of the Canadian dollar has increased the impact of U.S. dollar denominated crude oil prices on the company s revenues and earnings.

The presentation of the sensitivity of net income to changes in sales margins for total petroleum products has changed from a one cent (U.S.) a litre basis to a one dollar (U.S.) a barrel basis to conform to industry benchmarks unit of measure. The sensitivity of net income to changes in sales margins for total petroleum products was about $140 million (after-tax) for each one dollar (U.S.) a barrel difference at 2008 year-end, an increase of about $25 million from 2007 year-end. A decrease in the value of the Canadian dollar has increased the impact of U.S. dollar denominated crude oil and petroleum products prices on the company s revenues and earnings.

Item 8. Financial Statements and Supplementary Data.

Reference is made to the Index to Financial Statements on page F-1 of this report.

Syncrude Mining Operations

Syncrude s crude bitumen is contained within the unconsolidated sands of the McMurray Formation. Ore bodies are buried beneath 50 to 150 feet of overburden, have bitumen grades ranging from four to 14 weight percent and ore thickness of 115 to 180 feet. Estimates of synthetic crude oil reserves are based on detailed geological and engineering assessments of in-place crude bitumen volumes, the mining plan, historical extraction recovery and upgrading yield factors, installed plant operating capacity and operating approval limits. The in-place volume, depth and grade are established through extensive and closely spaced core drilling. In active mining areas, the approximate well spacing is 400 feet (150 wells per section) and in future mining areas, the well spacing is approximately 1,150 feet (20 wells per section). Proven reserves are within operating North and Aurora mines. In accordance with the long range mine plan approved by the Syncrude owners, there are extractable oil sands in the North and Aurora mines, with average bitumen grades of 10.6 and 11.2 weight percent respectively. After deducting royalties payable to the Province of Alberta, the company estimates its 25 percent net share of proven reserves at year end 2008 was equivalent to 734 million barrels of synthetic crude oil. Imperial s reserve assessment uses a six percent and seven percent bitumen grade cut-off for the North mine and Aurora mine respectively, a 90 percent overall extraction recovery, a 97 percent mining dilution factor and an 88 percent upgrading yield. Net proved reserves are based on the company s best estimate of average royalty rates over the life of the project and incorporate amendments to the Syncrude Crown Agreement. Actual future royalty rates may vary with production, price and costs.

The following table sets forth the company s share of net proven reserves of Syncrude after deducting royalties payable to the Province of Alberta:

	Synthetic Crude Oil		
	Base mine and North mine	**Aurora mine**	**Total**
	(millions of barrels)		
Beginning of year 2006	208	530	738
Revision of previous estimate		1	1
Production	(9)	(12)	(21)
End of year 2006	199	519	718
Revision of previous estimate			
Production	(11)	(13)	(24)
End of year 2007	188	506	694
Revision of previous estimate	27	36	63
Production	(11)	(12)	(23)
End of year 2008	**204**	**530**	**734**

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Kearl Project

Bitumen deposits at Kearl are found throughout sandstones within the Lower, Middle and Upper McMurray members, concentrated primarily within the Middle and Upper McMurray members. The oil sands occur over depths ranging from approximately 30 feet to as much as 450 feet below surface. The oil sands are about 130 feet in net thickness, but can be as thick as 230 feet. Mined bitumen reserve estimates are based upon detailed geological and engineering assessments of in-place crude bitumen volumes, the mining plan, demonstrated extraction recovery factors, planned operating capacity and operating approval limits. The in-place volume, depth and grade of the first phase were established through extensive and closely spaced core drilling with spacing of approximately 1,400 feet (14 wells per section). Imperial s reserve determination uses a seven percent bitumen grade cut-off by weight, a 77 percent overall extraction recovery (paraffinic froth treatment process) and a 95 percent mining dilution factor. Net proven reserves are based on the company s best estimate of average royalty rates over the life of the project and incorporate the Alberta government s new oil sands royalty regime. Actual future royalty rates may vary with production, price and costs.

The following table sets forth the company s share of net proven reserves for Kearl after deducting royalties payable to the Province of Alberta:

	Total (millions of barrels)
End of year 2007	
Additions	807
Production	
End of year 2008	807

Oil and Gas Producing Activities

The following information is provided in accordance with the United States Statement of Financial Accounting Standards No. 69, Disclosures about Oil and Gas Producing Activities .

Results of operations

	2008	**2007**	**2006**
		(millions of dollars)	
Sales to customers (1)	**3,343**	2,383	2,601
Intersegment sales (1)(2)	**1,297**	1,131	1,251
	4,640	3,514	3,852
Production expenses	**1,335**	1,074	1,016
Exploration expenses	**122**	100	32
Depreciation and depletion	**337**	371	467
Income taxes	**814**	526	564
Results of operations	**2,032**	1,443	1,773

Capital and exploration expenditures

	2008	**2007**	**2006**
		(millions of dollars)	
Property costs (3)			
Proved			
Unproved		1	
Exploration costs	**122**	100	32

Development costs	**525**	437	496
Total capital and exploration expenditures	**647**	538	528

Property, plant and equipment

	2008	2007
	(millions of dollars)	
Property costs (3)		
Proved	**3,168**	3,167
Unproved	**271**	148
Producing assets	**7,212**	6,706
Support facilities	**181**	180
Incomplete construction	**691**	579
Total cost	**11,523**	10,780
Accumulated depreciation and depletion	**7,840**	7,505
Net property, plant and equipment	**3,683**	3,275

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(1) 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 (page F-9) in external sales , intersegment sales and in purchases of crude oil and products .
(2) 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.
(3) 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.

Oil and Gas Reserves

Net Proved developed and undeveloped reserves (1)

	Crude oil and natural gas liquids			Natural gas
	Conventional	**Heavy oil (2)**	**Total**	**Total**
	(millions of barrels)			(billions of cubic feet)
Beginning of year 2006	83	551	634	747
Revisions	4	236	240	140
Improved recovery				
(Sale)/purchase of reserves in place	(1)		(1)	(6)
Discoveries and extensions				10
Production	(15)	(46)	(61)	(181)
End of year 2006	71	741	812	710
Revisions	24	(27)	(3)	75
Improved recovery		6	6	1
(Sale)/purchase of reserves in place	(1)		(1)	(12)
Discoveries and extensions		44	44	8
Production	(12)	(47)	(59)	(147)
End of year 2007	82	717	799	635
Revisions	**(8)**	**(66)**	**(74)**	**45**
Improved recovery		**(1)**	**(1)**	
(Sale)/purchase of reserves in place				
Discoveries and extensions		**25**	**25**	**4**
Production	**(10)**	**(45)**	**(55)**	**(91)**
End of year 2008	**64**	**630**	**694**	**593**

(1) Net reserves are the company s share of reserves after deducting the shares of mineral owners or governments or both. All reported reserves are located in Canada. Reserves of natural gas are calculated at a pressure of 14.73 pounds per square inch at 60°F.
(2) Heavy oil reserves typically are represented by crude oils with a viscosity of greater than 10,000 cP and recovered through enhanced thermal operations. Currently, the company s heavy oil reserves include reserves attributable to the commercial phases of Cold Lake production operations.

The information above describes changes during the years and balances of proved oil and gas reserves at year-end 2006, 2007 and 2008. The definitions used for oil and gas reserves are in accordance with the U.S. Securities and Exchange Commission s (SEC) Rule 4-10 (a) of Regulation S-X, paragraphs (2), (3) and (4).

Crude oil and natural gas reserve estimates are based on geological and engineering data, which have demonstrated with reasonable certainty that these reserves are recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made.

The year-end oil and gas reserves volumes as well as the reserves change categories shown in the proved reserves tables are calculated using December 31 prices and costs. These reserves quantities are also used in calculating unit-of-production depreciation rates and in calculating the standardized measure of discounted net cash flow. We understand that the use of December 31 prices and costs is intended to provide a point in time measure to calculate reserves and to enhance comparability between companies. However, the use of year-end prices for reserves estimation introduces short-term price volatility into the process, which is inconsistent with the long-term nature of the upstream business, since annual adjustments are required based on prices occurring on a single day. As a result, the use of prices from a single date is not relevant to the investment decisions made by the company.

Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the evaluation or revaluation of already available geologic, reservoir or production data; new geologic, reservoir or production data; or changes in year-end prices and costs that are used in the determination of reserves. This category can also include significant changes in either development strategy or production equipment/facility capacity. The quantities shown in the revisions category under heavy oil proved reserves in 2006 were due mainly to changes in year-end prices and costs that were used in the determination of reserves.

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Net proved reserves are determined by deducting the estimated future share of mineral owners or governments or both. For conventional crude oil and natural gas, net proved reserves are based on estimated future royalty rates as of the date the estimate is made incorporating the Alberta government new oil and gas royalty regime. For heavy oil, net proved reserves are based on the company s best estimate of average royalty rates over the life of each project and incorporate the Alberta government s new oil sands royalty regime. In all cases actual future royalty rates may vary with production, price and costs.

Oil-equivalent barrels (OEB) may be misleading, particularly if used in isolation. An OEB conversion ratio of 6,000 cubic feet to one barrel on an energy-equivalent conversion method is primarily applicable at the burner tip and does not represent a value equivalency at the well head.

No independent qualified reserves evaluator or auditor was involved in the preparation of the reserves data.

Net proved developed and undeveloped reserves of crude oil and natural gas as of December 31 (1)

	2008	2007	2006	2005	2004
Crude Oil (millions)					
Conventional					
Barrels	**64**	82	71	83	115
Heavy Oil					
Barrels	**630**	717	741	551	232
Total					
Barrels	**694**	799	812	634	347
Natural Gas (billions)					
Cubic feet	**593**	635	710	747	791

(1) Net reserves are the company s share of reserves after deducting the shares of mineral owners or governments or both.

Net proved developed reserves of crude oil and natural gas as of December 31 (1)

	2008	2007	2006	2005	2004
Crude Oil (millions)					
Conventional					
Barrels	**63**	82	71	81	111
Heavy Oil					
Barrels	**425**	483	501	368	232
Total					
Barrels	**488**	565	572	449	343
Natural Gas (billions)					
Cubic feet	**513**	539	608	643	704

(1) Net reserves are the company s share of reserves after deducting the shares of mineral owners or governments or both.

Standardized measure of discounted future cash flows

As required by SFAS 69, the standardized measure of discounted future net cash flows is computed by applying year-end prices, costs and legislated tax rates and a discount factor of 10 percent to net proved reserves. The standardized measure includes costs for future dismantlement, abandonment and remediation obligations. The company believes the standardized measure does not provide a reliable estimate of the company s expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions, including year-end prices, which represent a single point in time and therefore may cause significant variability in cash flows from year to year as prices change. The table below excludes the company s interest in Syncrude and Kearl.

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

	2008	2007	2006
		(millions of dollars)	
Future cash flows	**18,956**	32,415	36,751
Future production costs	**(13,558)**	(14,475)	(16,290)
Future development costs	**(4,642)**	(3,548)	(2,633)
Future income taxes	**(111)**	(3,655)	(5,039)
Future net cash flows	**645**	10,737	12,789
Annual discount of 10 percent for estimated timing of cash flows	**613**	(4,487)	(6,374)
Discounted future cash flows	**1,258**	6,250	6,415

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

	2008	2007	2006
		(millions of dollars)	
Balance at beginning of year	**6,250**	6,415	4,314
Changes resulting from:			
Sales and transfers of oil and gas produced, net of production costs	**(3,422)**	(2,430)	(2,839)
Net changes in prices, development costs and production costs	**(6,016)**	(625)	4,221
Extensions, discoveries, additions and improved recovery, less related costs	**25**	164	(4)
Development costs incurred during the year	**438**	412	411
Revisions of previous quantity estimates	**1,460**	1,285	87
Accretion of discount	**689**	710	568
Net change in income taxes	**1,834**	319	(343)
Net change	**(4,992)**	(165)	2,101
Balance at end of year	**1,258**	6,250	6,415

Within the past 12 months, the company has not filed oil and gas reserve estimates with any authority or agency of the United States.

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, 2008. 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 Securities and Exchange Commission s rules and forms.

Reference is made to page F-2 of this report for management s report on internal control over financial reporting and the report of the independent registered public accounting firm on the company s internal control over financial reporting as of December 31, 2008.

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.

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PART III

Item 10. Directors and Executive Officers of the Registrant.

The company currently has eight directors. Each director is elected to hold office until the close of the next annual meeting.

Each of the eight individuals listed below has been nominated for election at the annual meeting of shareholders to be held April 30, 2009. All of the nominees are now directors and have been since the dates indicated.

The following table provides information on the nominees for election as directors.

Name and current principal occupation or employment	Last major position or office with the company or Exxon Mobil Corporation	Director since	Holdings (4)(5)(6)	
K.T. (Krystyna) Hoeg Retired president and chief executive officer, Corby Distilleries Limited (1)(3)		May 1, 2008	Common shares of Imperial Oil Limited	0
			Deferred share units of Imperial Oil Limited	1,931
			Restricted stock units of Imperial Oil Limited	2,000
			Shares of Exxon Mobil Corporation	0
B.H. (Bruce) March Chairman, president and chief executive officer Imperial Oil Limited	President, Imperial Oil Limited, Calgary, Alberta	January 1, 2008	Common shares of Imperial Oil Limited	5,000
			Deferred share units of Imperial Oil Limited	0
			Restricted stock units of Imperial Oil Limited	43,300

			Shares of Exxon Mobil Corporation (7)	71,935
J.M. (Jack) Mintz Palmer Chair in Public Policy for the University of Calgary (1)(3)		April 21, 2005	Common shares of Imperial Oil Limited	1,000
			Deferred share units of Imperial Oil Limited	3,063
			Restricted stock units of Imperial Oil Limited	8,500
			Shares of Exxon Mobil Corporation	0
R.C. (Robert) Olsen Executive vice-president, ExxonMobil Production Company (2)	Chairman and production director, ExxonMobil International Limited, London, England	May 1, 2008	Common shares of Imperial Oil Limited	3,000
			Deferred share units of Imperial Oil Limited	0
			Restricted stock units of Imperial Oil Limited	0
			Shares of Exxon Mobil Corporation (7)	267,554

(Table continued on next page)

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Name and current principal occupation or employment	Last major position or office with the company or Exxon Mobil Corporation	Director since	Holdings (4)(5)(6)	
R. (Roger) Phillips Retired president and chief executive officer, IPSCO Inc. (steel manufacturing) (1)(3)		April 23, 2002	Common shares of Imperial Oil Limited	9,000
			Deferred share units of Imperial Oil Limited	17,736
			Restricted stock units of Imperial Oil Limited	12,625
			Shares of Exxon Mobil Corporation	2,000
P.A. (Paul) Smith Senior vice-president, finance and administration, and treasurer Imperial Oil Limited (3)	Controller and senior vice-president, finance and administration, Imperial Oil Limited, Calgary, Alberta	February 1, 2002	Common shares of Imperial Oil Limited	13,059
			Deferred share units of Imperial Oil Limited	0
			Restricted stock units of Imperial Oil Limited	181,850
			Shares of Exxon Mobil Corporation	1,662
S.D. (Sheelagh) Whittaker Corporate director (1)(3)		April 19, 1996	Common shares of Imperial Oil Limited	9,000
			Deferred share units of Imperial Oil Limited	33,426

		Restricted stock units of Imperial Oil Limited	12,625
		Shares of Exxon Mobil Corporation	0
V.L. (Victor) Young Corporate director of several corporations (1)(3)	April 23, 2002	Common shares of Imperial Oil Limited	11,250
		Deferred share units of Imperial Oil Limited	6,043
		Restricted stock units of Imperial Oil Limited	12,625
		Shares of Exxon Mobil Corporation	0

(1) Member of audit committee; member of executive resources committee; member of environment, health and safety committee; and member of nominations and corporate governance committee.

(2) Member of executive resources committee; member of environment health and safety committee; and member of nominations and corporate governance committee.

(3) Member of Imperial Oil Foundation board of directors.

(4) The information includes the beneficial ownership of common shares of Imperial Oil Limited and shares of Exxon Mobil Corporation, which information not being within the knowledge of the company, has been provided by the nominees individually.

(5) The company s plans for restricted stock units and deferred share units for selected employees and nonemployee directors are described on pages 40 through 42 and 50 through 51, respectively.

(6) The numbers for the company s restricted stock units and deferred share units represent the total of the restricted stock units and deferred share units received in 2006, 2007 and 2008 after the three-for-one share split in May 2006, plus three times the number of restricted stock units and deferred share units granted before the share split and still held by the director. The numbers for Exxon Mobil Corporation restricted stock include restricted stock and restricted stock units granted under its restricted stock plan which is similar to the company s restricted stock unit plan.

(7) B.H. March holds 27,185 common shares and 44,750 restricted shares and restricted stock units of Exxon Mobil Corporation. R.C. Olsen holds 105,854 common shares and 161,700 restricted shares and restricted stock units of Exxon Mobil Corporation.

The ages of the directors, nominees for election as directors, and the named executive officers of the company are: R.L. Broiles 51, C.W. Erickson 49, K.T. Hoeg 59, B.H. March 52, J.M. Mintz 57, R.C. Olsen 58, R. Phillips 69, P.A. Smith 55, S.M. Smith 51, S.D. Whittaker 61, V.L. Young 63. T.J. Hearn, who retired from the company on March 31, 2008 is 64.

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Certain of the directors and nominees for election as directors hold positions as directors of other Canadian and U.S. reporting issuers as follows:

Name	Other reporting issuers of which Director is also a director
K.T. Hoeg	Sun Life Financial Inc.
	Shoppers Drug Mart Corporation
	Canadian Pacific Railway Limited
	Canadian Pacific Railway Company
	Cineplex Galaxy Income Fund
J.M. Mintz	Brookfield Asset Management Inc.
R. Phillips	Canadian Pacific Railway Company
	Canadian Pacific Railway Limited
	Cliffs Natural Resources Inc.
	The Toronto Dominion Bank
V.L. Young	Bell Aliant Regional Communications Income Fund
	BCE Inc.
	Royal Bank of Canada

All of the directors, except for Krystyna T. Hoeg, Jack M. Mintz, and Sheelagh D. Whittaker have been engaged for more than five years in their present principal occupations or in other executive capacities with the same firm or affiliated firms. During the five preceding years, Krystyna T. Hoeg was president and chief executive officer of Corby Distilleries Limited until she retired in February 2007, Jack M. Mintz was president and chief executive officer of The C.D. Howe Institute until he retired in July 2006 and Sheelagh D. Whittaker was managing director of Electronic Data Systems until she retired in November 2005.

In addition to the named executive officers listed on page 37, the following are also executive officers of the company as of February 13, 2009.

Name and office	Office held since	Age
Sean R. Carleton	February 1, 2008	50

Controller		
Phil Dranse	August 1, 2008	55
Assistant treasurer		
Marvin E. Lamb	December 1, 2001	53
Director, corporate tax		
Brian W. Livingston	August 1, 2004	54
Vice-president, general counsel and corporate secretary		

All of the above executive officers have been engaged for more than five years at their current occupations or in other executive capacities with the company or its affiliates. All executive officers hold office until their appointment is rescinded by the board of directors or by the chief executive officer.

Audit Committee

The company has an audit committee of the board of directors. The following directors are the members of the audit committee: K.T. Hoeg, J.M. Mintz, R. Phillips, S.D. Whittaker and V.L. Young.

Audit Committee Financial Expert

The company s board of directors has determined that K.T. Hoeg, R. Phillips, S.D. Whittaker and V.L. Young meet the definition of audit committee financial expert and that they and J.M. Mintz are independent, as that term is defined in Multilateral Instrument 52-110 *Audit Committees*, the Securities and Exchange Commission rules and the listing standards of the NYSE Alternext and the New York Stock Exchange. The Securities and Exchange Commission has indicated that the designation of an audit committee financial expert does not make that person an expert for any purpose, or impose any duties, obligations or liability on that person that are greater than those imposed on members of the audit committee and board of directors in the absence of such designation or identification.

Code of Ethics

The company has a code of ethics that applies to all employees, including its principal executive officer, principal financial officer and principal accounting officer. The code of ethics consists of the company s ethics policy, conflicts of interest policy, corporate assets policy, directorships policy, and procedures and open door communication. Those documents are available at the company s web site www.imperialoil.ca.

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Item 11. Company Executives and Executive Compensation.

Named Executive Officers of the Company

The named executive officers of the company at the end of 2008 were:

B.H. (Bruce) March, Chairman, president and chief executive officer;

P.A. (Paul) Smith, Senior vice-president, finance and administration, and treasurer;

R.L. (Randy) Broiles, Senior vice-president, resources division;

C.W. (Chris) Erickson, Vice-president and general manager, refining and supply; and

S.M. (Simon) Smith, Vice-president and general manager, fuels marketing.

T.J. (Tim) Hearn was chairman and chief executive officer from January 1, 2008 until his retirement on March 31, 2008.

Senior Executive Compensation

The executive resources committee of the board of directors is composed of the five independent directors and R.C. Olsen, who is employed by ExxonMobil Production Company. The executive resources committee is responsible for corporate policy on compensation and for specific decisions on the compensation of the chief executive officer and key senior executives and officers reporting directly to that position. In addition to compensation matters, the committee is also responsible for succession plans and appointments to senior executive and officer positions, including the chief executive officer.

R.C. Olsen is not independent by virtue of his employment with ExxonMobil Production Company, which is a division of Exxon Mobil Corporation, which owns beneficially 596,357,122 common shares, representing 69.6 percent of the outstanding voting shares of the company. For that reason the company is a controlled company . During 2008, the membership of the executive resources committee was as follows:

R. Phillips - Chair

V.L. Young - Vice-chair

K.T. Hoeg (since May 2008)

J.M. Mintz

R.C. Olsen (since July 2008)

J.F. Shepard (until May 2008)

S.D. Whittaker

B.H. March periodically attends meetings at the request of the committee.

Report of Executive Resources Committee on Executive Compensation

The Executive Resources Committee of the Board of Directors has reviewed and discussed the Compensation Discussion and Analysis for 2008 with management of the company. Based on that review and discussion, the committee recommended to the board that the Compensation Discussion and Analysis be included in the company s management proxy circular for the 2009 annual meeting of shareholders.

Submitted on behalf of the executive resources committee:

R. Phillips - Chair	J.M. Mintz
V.L. Young - Vice-chair	R.C. Olsen
K.T. Hoeg	S.D. Whittaker

Compensation Discussion and Analysis

Overview

Providing energy to meet Canada s demands is a complex business. The company meets this challenge by taking a long-term view to managing its business rather than reacting to short-term business cycles. As such, the compensation program of the company aligns with this long-term business approach and key business strategies as outlined below.

Business Environment

Large capital expenditures with long investment periods;
Complex operating and financial risks;
National scope of company operations; and
Commodity-based cyclical product prices.

Key Business Strategies

Grow profitable sales volumes;
Disciplined, selective and long-term focus on improving the productivity of the company s asset mix;
Flawless execution; and
Best-in-class cost structure to ensure industry-leading returns on capital and superior cash flow.

Focus on these key strategies for the business is a company priority and ensures long-term growth in shareholder value.

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Key Elements of the Compensation Program

The key elements of the company s compensation program and staffing objectives that support the business environment and key business strategies are:

- long-term career orientation with high individual performance standards (see page 39);
- base salary that rewards individual performance and experience (see page 39);
- annual bonus grants based on business performance, as well as individual performance and experience (see pages 39 through 40);
- payment of a large portion of executive compensation in the form of restricted stock units with lengthy vesting periods (see pages 40 through 41);
- retirement benefits (pension and savings plans) that provide for financial security after employment (see pages 42 through 44).

The company s executive compensation program is designed to:

- reinforce the company s orientation toward career employment and individual performance;
- acknowledge the long-term nature of the company s business;
- reinforce its philosophy that the experience, skill and motivation of the company s executives are significant determinants of future business success; and
- ensure alignment with long-term shareholder interests.

The compensation program emphasizes competitive salaries and performance-based incentives as the primary instruments to attract, develop and retain key personnel.

Other Supporting Compensation and Staffing Practices

- A long established program of management development and succession planning is in place to reinforce a career orientation and ensure continuity of leadership.
- All executives participate in common programs (the same salary, incentive and retirement programs). Within these programs, the compensation of executives is differentiated based on individual performance assessment, level of responsibility and individual experience. All senior executives on loan assignment from ExxonMobil participate in common programs, as well, which are administered by ExxonMobil.
- Substantial amounts of executive compensation for the named executive officers are at risk of forfeiture, if the executive engages in activity that is detrimental to the company.
- Inappropriate risk taking is discouraged by requiring senior executives to hold a substantial portion of their equity incentive award for their entire career and in some cases beyond retirement.
- The use of perquisites at the company is limited, and mainly tied to financial planning for senior executives, and the use of club memberships is largely tied to building business relationships.
- No tax assistance is provided by the company on any elements of executive officer compensation or perquisites other than relocation. The relocation program is broad-based and applies to all management, professional, technical and executive transferred employees.

Employee Appraisal and Ranking Process

The assessment of individual performance is conducted through the company s employee appraisal program. Conducted annually, the appraisal process assesses performance against business performance measures and objectives relevant to each employee, including the means by which performance is achieved. These business performance measures include:

- total shareholder return;
- net income;
- return on capital employed;
- cash distributed to shareholders;
- safety, health, and environmental performance;
- operating performance of the Upstream, Downstream, and Chemical segments;
- business controls; and
- effectiveness of actions that support the long-term, strategic direction of the company.

The ranking process, which is an integral part of the appraisal process, involves comparative assessment of employee performance using a standard process throughout the organization and at all levels. The appraisal process is integrated with the compensation program and also with the executive development process. Both have been in place for many years and are the basis for planning individual development and succession planning for management positions. The decision-making process with respect to compensation requires judgment, taking into account business and individual performance and responsibility. Quantitative targets or formulas are not used to assess individual performance or determine the amount of compensation.

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Compensation Program

Career Orientation

The company s objective is to attract, develop and retain over a career the best talent available. It takes a long period of time and significant investment to develop the experienced executive talent necessary to succeed in the company s business; senior executives must have experience with all phases of the business cycle to be effective leaders. The company s compensation program elements reinforce the long term approach. Career orientation among a dedicated and highly skilled workforce, combined with the highest performance standards, contributes to the company s leadership in the industry and serves the interests of shareholders in the long term. The company service of the named executive officers reflects this strategy. Their career service ranges from 27 to over 29 years.

Consistent with the company s long-term career orientation, high-performing executives typically earn substantially higher levels of compensation in the final years of their careers than in the earlier years. This pay practice reinforces the importance of a long-term focus in making decisions that are key to business success.

Because the compensation program emphasizes individual experience and sustained performance, executives holding similar positions may receive substantially different levels of compensation.

The company s executive compensation program is composed of base salaries, cash bonuses and medium and long-term incentive compensation. The company does not have written employment contracts or any other agreement with its named executive officers providing for payments on change of control or termination of employment.

Base Salary

Salaries provide executives with a base level of income. The level of annual salary is based on the executive s responsibility, performance assessment and career experience. The salary program in 2008 maintained the company s competitive position on salaries in the marketplace. Individual salary increases vary depending on each executive s performance assessment and other factors such as time in position and potential for advancement. Salary decisions also directly affect the level of retirement benefits since salary is included in the retirement-benefit calculation. Thus, the level of retirement benefits is also performance-based like other elements of compensation.

Annual Bonus

Annual bonuses are typically granted to approximately 95 executives to reward their contributions to the business during the past year. Bonuses are drawn from an aggregate bonus pool established annually by the executive resources committee based on the company s financial and operating performance, and can be highly variable depending on annual financial and operating results.

In setting the size of the annual bonus pool and individual executive awards, the executive resources committee:

- considers input from the chairman, president and chief executive officer on the performance of the company and from the company s internal compensation advisors regarding compensation trends as obtained from external consultants;
- considers annual net income of the company and other key business performance indicators as described on page 38; and
- uses judgment to manage the overall size of the annual bonus pool taking into consideration the cyclical nature and long-term orientation of the business.

The 2008 annual bonus pool was $11.9 million versus $12.8 million in 2007. This reflects the combined value at grant of annual cash bonus and earnings bonus units. Given the mix of participants, in 2008, the overall bonus pool was slightly lower than the previous year, but continued to reflect improved financial results and operating performance. In relation to this, the company s net income for 2008 was a record $3.9 billion (up 22 percent), return on shareholders equity was 46 percent, return on capital employed was 45 percent and total annual shareholders return was -24.3 percent. Changes in individual cash bonus awards vary depending on each executive s performance assessment.

The annual bonus program incorporates unique elements to further reinforce retention and recognize performance. Awards under this program are generally delivered as:

- 50 percent cash paid in the year of grant; and
- 50 percent earnings bonus units with a delayed payout based on cumulative earnings performance.

The cash component is intended to be a short-term incentive, while the earnings bonus unit plan is intended to be a medium-term incentive. Earnings bonus units are made available to selected executives to promote individual contribution to sustained improvement in the company s business performance and shareholder value. Earnings bonus units are generally equal to and granted in tandem with cash bonuses.

Specifically, earnings bonus units are cash awards that are tied to future cumulative earnings per share. Earnings bonus units pay out when a specified level of cumulative earnings per share is achieved or within five years, whichever is earlier.

For earnings bonus units granted in 2008, the maximum settlement value (trigger) or cumulative earnings per share required for payout was increased to $2.75 per unit versus $2.25 in 2007, to reinforce the company s principle of continuous improvement in business performance and to reflect the reduction in the number of outstanding shares pursuant to the company s share purchase program. The trigger of $2.75 is intentionally set at a level that is expected to be achieved within the five-year period.

If cumulative earnings per share did not reach $2.75 within five years, the payment with respect to the earnings bonus unit would be reduced to an amount equal to the number of units times the actual cumulative earnings per share over the period.

The annual bonus includes the combined value of the cash bonus and delayed earnings bonus unit portion and is intended to be competitive with the annual bonus awards of other major comparator companies adjusted to reflect the company s performance relative to its comparators. The earnings bonus units are designed such that the timing of the payout is tied to the rate of the company s future earnings; however, it is not intended to vary the amount of the award based on future earnings. In so doing, the delayed portion of the annual bonus, that is the earnings bonus unit, puts part of the annual bonus at risk of forfeiture and thus reinforces the performance basis of the annual bonus grant.

Prior to payment, the earnings bonus units may be forfeited if the executive leaves the company before age 65, or engages in activity that is detrimental to the company.

Long-Term Incentive Compensation

Restricted Stock Units

In December 2002, the company introduced a restricted stock unit plan, which is the company s primary long-term incentive compensation plan. Given the long-term nature of the company s business, granting compensation in the form of restricted stock units with long vesting periods keeps executives focused on the key premise that decisions made today affect the performance of the organization and company stock for many years to come. This practice supports a risk/reward model that reinforces a long-term view, which is critical to the company s business success, and discourages inappropriate risk taking. The amount granted is intended to provide an incentive to promote individual contribution to the company s performance and motivation to remain with the company. The amount is computed by reference to the most recent ranking of performance as an indication of future potential, but may also consider an adjustment at time of grant, if near term performance is deemed to have changed significantly at time of grant. This type of compensation removes employee discretion in the exercise of restricted stock units and ensures alignment with the long-term interests of shareholders and reinforces retention objectives. The company does not re-price restricted stock awards. The utilization of restricted stock units, instead of stock options, and the determination of annual grants on a share-denominated versus price basis help reinforce this practice. Restricted stock units are not included in pension calculations.

The restricted stock unit plan is a straightforward, primarily cash-based approach to long-term incentive compensation. Grant level guidelines for the restricted stock unit program are generally held constant for long periods of time. The intent of the plan is not to frequently change the number of shares awarded for the same level of individual performance and classification or level of responsibility. The program is a share-denominated program, not a price-denominated program, to better align with the gains and losses experienced by shareholders. A change may be required as a result of periodic checks against the market every three to five years or as a result of any subdivision, consolidation, or reclassification of the shares of the company or other relevant change in the capitalization of the company. The company does not offset losses on prior grants with higher share awards in subsequent grants nor does the company re-price restricted stock units.

In 2006, the guidelines were reviewed in light of the company s three-for-one share split. Given the significant appreciation in the company s share price over the previous several years, restricted stock unit guidelines were adjusted on a two-for-one basis rather than the three-for-one share split. This had the effect of reducing grant values in 2006 and 2007 compared to earlier years. In 2008, after an analysis of the competitive positioning of the company s restricted stock unit program, the executive resources committee determined that some levels of restricted stock units would be increased to ensure appropriate on-going competitive positioning of the plan. In 2008, 748 employees were granted 1,750,795 restricted stock units, including 100 executives.

Exercise of Restricted Stock Units and Amendments to the Restricted Stock Unit Plan

Restricted stock units will be exercised only during employment except in the event of death, disability or retirement. Restricted stock units cannot be assigned. In the case of any subdivision, consolidation, or reclassification of the shares of the company or other relevant change in the capitalization of the company, the company, in its discretion, may make appropriate adjustments in the number of common shares to be issued and the calculation of the cash amount payable per restricted stock unit.

Each restricted stock unit entitles the recipient the right to receive from the company, upon exercise, an amount equal to the five day average closing price of the company s shares on the exercise date and the four preceding trading days. Fifty percent of the units will be exercised on the third anniversary of the grant date, and the remainder will be exercised on the seventh anniversary of the grant date. The company will pay the recipients cash with respect to each unexercised unit granted to the recipient corresponding in time and amount to the cash dividend that is paid by the company on a common share of the company. The restricted stock unit plan has been amended for units granted in 2002 and future years by providing that the recipient may receive one common share of the company per unit or elect to receive the cash payment for the units to be exercised on the seventh anniversary of the grant date.

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There are 7,928,818 common shares that may be issued in the future with respect to outstanding restricted stock units that represent about 0.93 percent of the company s currently outstanding common shares. The company s directors, officers and vice-presidents as a group hold 15 percent of the unexercised restricted stock units that give the recipient the right to receive common shares. The maximum number of common shares that any one person may receive from the exercise of restricted stock units is 488,200 common shares, which is about 0.06 percent of the currently outstanding common shares. R.L. Broiles and C.W. Erickson hold ExxonMobil restricted stock units. B.H. March also holds ExxonMobil restricted stock units granted in 2007 and previous years, as well as the company s restricted stock units granted in 2008.

On February 26, 2008, the restricted stock unit plan was also amended by the company to provide that the number of common shares of the company issuable under the plan to any insiders (as defined by the Toronto Stock Exchange) cannot exceed 10 percent of the issued and outstanding common shares, whether at any time or as issued in any one year. The Toronto Stock Exchange advised that this amendment did not require shareholder approval.

Effective May 1, 2008, the restricted stock unit plan was amended by the company to include an additional vesting period option for 50 percent of restricted stock units to vest on the fifth anniversary of the date of grant, with the remaining 50 percent of the grant to vest on the later of the tenth anniversary of the date of grant or the date of retirement of the grantee. The recipient of such restricted stock units may receive one common share of the company per unit or elect to receive the cash payment for all units to be exercised. The choice of which vesting period to use will be at the discretion of the company. Effective May 1, 2008, the restricted stock unit plan was further amended to set out which amendments in the future will require shareholder approval, and which amendments will only require director approval and to set an exercise price based on the weighted average price of the company s shares on the exercise date and the four consecutive trading days immediately prior to the exercise date. Shareholder approval for these changes was received on May 1, 2008.

In respect of restricted stock units granted in 2008:

- to the chairman, president and chief executive officer:
  - 50 percent of each grant is exercisable on the fifth anniversary of the date of grant; and
  - the balance is exercisable on the later of the tenth anniversary of the date of grant or the date of retirement; and
- to all other senior executives:
  - 50 percent of each grant is exercisable on the third anniversary of the date of grant; and
  - the balance is exercisable on the seventh anniversary of the date of grant.

The long vesting periods, which are longer than those in use by many other companies, reinforce the company s focus on growing shareholder value over the long term by subjecting a large percentage of executive compensation and the personal net worth of senior executives to the long term return on the company s stock realized by shareholders. The vesting period for restricted stock unit awards is not subject to acceleration, except in the case of death.

Forfeiture Risk

Restricted stock units are subject to forfeiture if:

- A recipient retires or terminates employment with the company. The company has indicated its intention not to forfeit restricted stock units of employees who retire at age 65. In other circumstances, where a recipient retires or terminates employment, the company may determine that restricted stock units shall not be forfeited.
- During employment or during the period of 24 months after the termination of employment, the recipient, without the consent of the company, engaged in any business that was in competition with the company or otherwise engaged in any activity that was detrimental to the company.

Deferred Share Units

In 1998, an additional form of long-term incentive compensation (deferred share units) was made available to nonemployee directors (as described on pages 50 through 51) and to selected executives whose decisions are considered to have a direct effect on the long term financial performance of the company. The selected executives can elect to receive all or part of their cash bonus compensation in the form of such units. The number of units granted to an executive is determined by dividing the amount of the executive s bonus elected to be received as deferred share units by the average of the closing prices of the company s shares on the Toronto Stock Exchange for the five consecutive trading days (average closing price) immediately prior to the date that the bonus would have been paid to the executive. Additional units will be granted to recipients of these units, in respect of unexercised units, based on the cash dividend payable on the company 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.

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An executive may not exercise these units until after termination of employment with the company and must exercise the units no later than December 31 of the year following termination of employment with the company. The units held must all be exercised on the same date. On the date of exercise, the cash value to be received for the units will be determined by multiplying the number of units exercised by the average closing price immediately prior to the date of exercise. In 2008, no executive elected to receive deferred share units.

The deferred share unit plan was amended on November 20, 2008 to provide that for U.S. taxpayers, subject to the United States Internal Revenue Code, Section 409A, for units earned after December 31, 2004, the exercise date must not be later than five months after the date of termination of employment and the date for the cash payment from the plan will be six months after the date of termination of employment.

Retirement Benefits

Named executive officers participate in the same pension plan, including supplemental retirement income provisions, as other employees. B.H. March, R.L. Broiles and C.W. Erickson participate in the Exxon Mobil Corporation pension plans (both tax-qualified and nonqualified).

Pension Plan Benefits

The following table sets forth the estimated annual benefits that would be payable to each named executive officer of the company upon retirement under the company s pension plan and supplemental retirement income provisions and Exxon Mobil Corporation s tax qualified and non-qualified pension plans, and the change in the accrued obligation for each named executive officer of the company in 2008.

Name	Number of years credited service December 31, 2008 (#)	Annual benefits payable ($)		Accrued obligation at start of year ($) (5)	Compensatory change ($) (6)	Non-compensatory change ($) (7)	Accrued obligation at year end ($) (8)
		At year end (3)	At age 65 (4)				
B.H. March (1)							
P.A. Smith (2)	28.9	365,100	482,800	3,624,900	(13,100)	(573,100)	3,038,700
R.L. Broiles (1)							
C.W. Erickson (1)							
S.M. Smith (2)	27.1	308,200	464,800	2,752,100	350,200	(591,900)	2,510,400
T.J. Hearn (2) (9) (retired from the company on March 31, 2008)	41.6	97,200	97,200	24,482,600	124,200	(23,586,200)	1,020,600

(1) Member of the Exxon Mobil Corporation pension plans, including tax qualified and non-qualified plans. As of December 31, 2008, B.H. March had 28.5 years of credited service, R.L. Broiles had 29.6 years and C.W. Erickson had 27.5 years. All amounts referenced were converted from U.S. dollars to Canadian dollars at the average 2008 exchange rate of 1.066.

(2) Member of the company pension plan as supplemented by payments from the company.

(3) For members of the company pension plan, the annual benefits include the amount of the accrued annual lifetime pension from the company s registered pension plan and supplemented by payments from the company. For members of the Exxon Mobil Corporation pension plans, the annual benefits include the accrued annual lifetime pension from the Exxon Mobil Corporation tax qualified plan and the accrued annual amount calculated under the Exxon Mobil Corporation non-qualified plan. Non-qualified plan benefits are payable only as a lump sum equivalent upon retirement. For B.H. March, this value was $379,281, for R.L. Broiles, this value was $331,911 and for C.W. Erickson, this value was $311,141.

(4) For members of the company pension plan, the annual benefits include the amount of the accrued annual lifetime pension from the company s registered pension plan and supplemented by payments from the company that would be earned to age 65 assuming final average earnings as at December 31, 2008. For members of the Exxon Mobil Corporation pension plan, the annual benefits include the annual lifetime pension from Exxon Mobil Corporation s tax qualified plan and the annual amount calculated under the Exxon Mobil Corporation non-qualified plans that would be earned to age 65 assuming final average earnings as at December 31, 2008. Non-qualified plan benefits are payable only as a lump sum equivalent upon retirement. For B.H. March, this value was $550,374, for R.L. Broiles, this value was $486,517 and for C.W. Erickson, this value was $493,350.

(5) For members of the company s pension plan, the Accrued obligation at start of year is defined for purposes of Financial Accounting Standard 87 (FAS 87) and is calculated based on earnings eligible for pension as described on page 43 and Yearly Maximum Pensionable Earnings (YMPE) as defined by the Canada Revenue Agency, projected to retirement and pro-rated on service to the date of valuation, December 31, 2007. The calculations assume that the Canada Pension Plan offset is based on the annual maximum benefit at retirement and the Old Age Security (OAS) offset is based on the OAS benefit in the fourth quarter of 2007 projected to retirement. For members of the Exxon Mobil Corporation pension plans, the Accrued obligation at start of year is defined for purposes of FAS 87 and is calculated based on earnings eligible for pension as described on page 43. The calculations assume that the U.S. Social Security offset against the Exxon Mobil Corporation qualified plan benefit is calculated on the basis of the Social Security law in effect as of year end 2007. For B.H. March, this value was $2,448,424, for R.L. Broiles, this value was $2,295,189 and for C.W. Erickson, this value was $1,793,459.

(6) The value for Compensatory change includes service cost for 2008. Service cost for 2008 is calculated by using the individual s additional pensionable service in 2008 and the actual salary and bonus received in 2008 as described on page 43. There were no plan amendments in 2008 that affected these benefits. The service cost is calculated on a basis that is consistent with FAS 87 and with the valuation that was performed as at that date for accounting purposes for the plan as a whole. For B.H. March, this value was $611,774, for R.L. Broiles, this value was $254,286 and for C.W. Erickson, this value was $234,192.

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(7) The value for Non-compensatory change includes impact of experience not related to earnings, benefit payments and change in measurement assumptions. With respect to the company pension plan, the discount rate used to determine the accrued obligation at the end of 2008 increased to 7.50 percent, up from 5.75 percent at the end of 2007, thereby causing the Non-compensatory change to be negative. For members of the Exxon Mobil Corporation pension plans, the value for Non-compensatory change includes the impact of experience not related to earnings or service. This includes the effect of interest, based on a discount rate of 6.25 percent in each year, and operation of the plan s rules for converting annuities to lump sums upon retirement. For B.H. March, this value was $355,560, for R.L. Broiles, this value was $296,220 and for C.W. Erickson, this value was $73,612.

(8) For members of the company s pension plan, the Accrued obligation at year end is defined for purposes of FAS 87 and is calculated based on earnings eligible for pension as described on page 43 and YMPE, projected to retirement and pro-rated on service to the date of valuation, December 31, 2008. The calculations assume that the Canada Pension Plan offset is based on the annual maximum benefit at retirement and the OAS offset is based on the OAS benefit in the fourth quarter of 2008 projected to retirement. For members of the Exxon Mobil Corporation pension plans, the Accrued obligation at year end is defined for purposes of FAS 87 and is calculated based on earnings eligible for pension as described on page 43. The calculations assume that the U.S. Social Security offset against the Exxon Mobil Corporation qualified plan benefit is calculated on the basis of the Social Security law in effect as of year end 2008. For B.H. March, this value was $3,415,757, for R.L. Broiles, this value was $2,845,696 and for C.W. Erickson, this value was $2,101,262.

(9) T.J. Hearn retired on March 31, 2008. At retirement, T.J. Hearn was provided the standard election option to receive his supplemental retirement income as a monthly annuity or a lump sum. T.J. Hearn exercised his option to receive the benefit as a lump sum. The change in non-compensatory obligation was adjusted accordingly.

The registered pension plan and supplemental retirement income provisions provide an annual benefit of 1.6 percent of earnings per each year of service with respect to the named executive officers, with an offset for government benefits. Earnings, for this purpose, include average base salary during the last 36 consecutive months of service prior to retirement or the highest consecutive three calendar years of earnings in the last 10 years of service prior to retirement and the average annual bonus for the highest three of the last five years prior to retirement for eligible executives, but do not include long-term compensation, including restricted stock units. By limiting inclusion of bonuses in pensionable earnings to those granted in the five years prior to retirement, there is a strong motivation for executives to continue to perform at a high level. Annual bonus includes the cash amounts that are paid at grant, any cash amount deferred as described on pages 39 through 40 and the value of any earnings bonus units received, as described on pages 39 through 40. The aggregate maximum settlement value that could be paid for earnings bonus units is included in the employee s final three year average earnings for the year of grant of such units. The portion of annual bonus deferred, and the value of earnings bonus units, are not intended to be at risk and, therefore, are included for pension purposes in the year of grant rather than the year of payment. An employee may also elect to forego three of the six percent of the company s contributions to the savings plan under one of the options of that plan (except for B.H. March, R.L. Broiles and C.W. Erickson), to receive additional pension value equal to 0.4 percent of the employee s final three year average earnings , multiplied by the employee s years of service, while foregoing such company contributions. In addition to the pension payable under the plan, the company has paid and may continue to pay a supplemental retirement income to employees who have earned a pension in excess of the maximum pension under the Income Tax Act.

The remuneration used to determine the payments on retirement to the individuals named in the summary compensation table on page 47 corresponds generally to the salary, bonus and earnings bonus units received in the current year, as described in the previous paragraph. As of February 13, 2009, the number of completed years of service with Imperial Oil Limited used to determine payments on retirement was 29 for P.A. Smith and 27 for S.M. Smith. T.J. Hearn retired from the company on March 31, 2008 with 41 completed years of service.

B.H. March, R.L. Broiles and C.W. Erickson are not members of the company s pension plan, but are members of Exxon Mobil Corporation s pension plans. Under those plans, B.H. March has 28 years of credited service, R.L. Broiles has 29 years of credited service and C.W. Erickson has 27 years of credited service. Their respective pensions are payable in U.S. dollars. Pay for the purpose of the pension calculation is based on final average base salary over the highest 36 consecutive months in the 10 years of service prior to retirement, and the average annual bonus for the three highest grants out of the last five grants prior to retirement.

Savings Plan Benefits

The company maintains a savings plan into which career employees with more than one year of service may contribute between one and 30 percent of normal earnings. The company provides equal matching contributions to a maximum of six percent when an employee participates in the pre-1998 historic 1.6 percent defined-benefit pension arrangement. The current version of the historic 1.6 percent defined benefit plan has been in place since 1976; predecessor plans have been in place since 1919. All named executive officers are members of the historic 1.6 percent plan, except for B.H. March, R.L. Broiles and C.W. Erickson who participate in the Exxon Mobil Corporation savings plan and tax qualified and non-qualified pension plans. An employee may also elect to forego three of the six percent of the company s contributions to the savings plan to receive additional pension value equal to 0.4 percent of the employee s final three year average earnings , multiplied by the employee s years of service, while foregoing such company contributions (except for B.H. March, R.L. Broiles and C.W. Erickson). T.J. Hearn elected to forego three of the six percent of the company s contribution to the savings plan in order to receive this additional pension value.

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Employee and company contributions can be allocated in any combination to a non-registered (tax-paid) account or a registered (tax-deferred) group retirement savings plan (RRSP) account, subject in the latter case to contribution limits under the Income Tax Act.

Available investment options include cash savings, a money market mutual fund, a suite of four index-based mutual funds and company shares. Company matching contributions must be allocated to company shares initially, and remain in that investment for a minimum of 24 months, after which they can be redeemed in favour of the other investment options.

During employment, withdrawals are only permitted from employee contributions and investment earnings within the tax-paid account, to a maximum of three withdrawals per year. Assets in the RRSP account, and company contributions to the tax-paid account, may only be withdrawn upon retirement or termination of employment, reinforcing the company s long-term approach to total compensation. Income Tax regulations require RRSP s to be closed by the end of the year in which the individual reaches age 71.

Named Executive Officer Compensation

Compensation Decision Making Process and Considerations

Benchmarking

In addition to the assessment of business performance, individual performance and level of responsibility, the executive resources committee relies on market comparisons to a group of 25 major Canadian companies with revenues in excess of $1 billion a year. Canadian companies are selected on the basis of being large in scope and complexity, capital intensive and proven sustainability. The 25 companies benchmarked are as follows:

Comparator Companies - Named Executive Officers

Agrium Inc.	EnCana Corporation	Procter & Gamble Inc.
BCE Inc.	General Electric Canada	Royal Bank of Canada
BP Canada Energy Company	Husky Energy Inc.	Shell Canada Limited
Canadian Tire Corporation Limited	IBM Canada Ltd.	Suncor Energy Inc.
Chevron Canada Limited	Irving Oil Limited	Talisman Energy Inc.
Canadian Natural Resources Limited	Lafarge Canada Inc.	TransCanada Corporation
ConocoPhillips Canada	Nexen Inc.	Vale Inco Limited
Canadian Pacific Railway Limited	Nova Chemicals Corporation	
Enbridge Inc.	Petro-Canada	

The company is a national employer drawing from a wide range of disciplines. It is important to understand its competitive position relative to a variety of oil and non-oil employers. Annual market comparisons, based on survey data, are prepared by independent external compensation consultant, Towers Perrin, with additional analysis and recommendation provided by the company s internal compensation advisors. Consistent with the executive resources committee s practice of using well-informed judgment rather than formulae to determine executive compensation, the committee does not target any specific percentile among comparator companies to align compensation. Rather, on a case-by-case basis, depending on the scope of market coverage represented by a particular comparison, total compensation (excluding perquisites) is targeted to a range between the mid-point and the upper quartile of comparable employers, reflecting the company s emphasis on quality management. This approach applies to salaries and the annual bonus.

As a secondary source of data, the company also considers a comparison with Exxon Mobil Corporation, when it determines the annual bonus program. For the restricted stock unit program, the executive resources committee also reviews a summary of data for a subset of the comparator companies provided by the same external consultant above, in order to assist in assessing total value of long-term compensation grants. This approach provides the company with the ability to better respond to changing business conditions, manage salaries based on a career orientation, minimize potential for automatic increasing of salaries, which could occur with an inflexible and narrow target among benchmarked companies, and finally to differentiate salaries based on performance and experience levels among executives.

The elements of the ExxonMobil compensation program, that include salary and annual bonus and equity (long-term) compensation considerations for B.H. March, R.L. Broiles and C.W. Erickson, are similar to those of the company. The data used for long-term compensation determination for B.H. March is as described above, as he received Imperial Oil Limited restricted stock units in 2008. The executive resources committee reviews and approves recommendations for each named executive officer prior to implementation. B.H. March s compensation determination is described in more detail on pages 45 through 46.

2008 Named Executive Officer Compensation Assessment

When determining the annual compensation for the named executive officers, the executive resources committee has reflected on the following business performance result indicators in its determination of 2008 salary and incentive compensation.

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Business Performance Results for Consideration

The operating and financial performance measurements listed below and the company s continued maintenance of sound business controls and a strong corporate governance environment formed the basis for the salary and incentive award decisions made by the executive resources committee in 2008. The executive resources committee considered the results over multiple years, in recognition of the long-term nature of the company s business.

- Total shareholder return of about -24 percent. Ten-year annual average of about 19 percent.
- Record earnings of $3.9 billion. Five-year annual average earnings of $3.0 billion.
- Strong results in the areas of safety, health, and environment.
- Industry-leading return on average capital employed of 45 percent, with an average of 30 percent since the beginning of 2000.
- $330 million distributed to shareholders as dividends in 2008.
- $2.2 billion distributed to shareholders through the share purchase program in 2008 and $15 billion since 1995.
- Effective business controls and corporate governance.

Performance Assessment Considerations

The above results form the context in which the committee assesses the individual performance of each senior executive, taking into account experience and level of responsibility.

Annually, the chairman, president and chief executive officer reviews the performance of the senior executives in achieving business results and individual development needs.

The same long-term business strategies noted on page 37 and results on page 45 are key elements in the assessment of the chairman, president and chief executive officer s performance by the executive resources committee.

The performance of all named executive officers is also assessed by the board of directors throughout the year during specific business reviews and board committee meetings that provide reports on strategy development; operating and financial results; safety, health, and environmental results; business controls; and other areas pertinent to the general performance of the company.

The executive resources committee does not use quantitative targets or formulae to assess executive performance or determine compensation. The executive resources committee does not assign weights to the factors considered. Formula-based performance assessments and compensation typically require emphasis on two or three business metrics. For the company to be an industry leader and effectively manage the technical complexity and integrated scope of its operations, most senior executives must advance multiple strategies and objectives in parallel, versus emphasizing one or two at the expense of others that require equal attention.

Senior executives and officers are expected to perform at the highest level or they are replaced. If it is determined that another executive is ready and would make a stronger contribution than one of the current incumbents, a replacement plan is implemented.

2008 CEO Compensation Assessment

B.H. March was elected chairman, president and chief executive officer of the company on April 1, 2008. Mr. March is a 29-year veteran of ExxonMobil, including service with heritage Mobil Corporation before the merger with Exxon Corporation on November 30, 1999. Mr. March has extensive operating and management experience in the oil and gas business, including assignments in multiple locations in the United States, as well as experience working in London and Brussels. His level of salary was determined by the executive resources committee based on his individual performance and to align with that of his peers in ExxonMobil. It was also the objective of the executive resources committee to ensure appropriate internal alignment with senior management in the company. The committee also approved a salary increase of $35,000 U.S. to $485,000 U.S., effective January 1, 2009.

Mr. March s 2008 annual bonus was based on his performance as assessed by the executive resources committee since his assignment to the position of chairman, president and chief executive officer. His long-term incentive award was paid in the form of company restricted stock units, not ExxonMobil restricted stock, to reinforce alignment of his interests with that of the company s shareholders. His company restricted stock units are subject to vesting periods longer than those applied by most companies conducting business in Canada. Fifty percent of the restricted stock units awarded vest in five years and the other 50 percent vest on the later of 10 years from the date of grant or the date of retirement. The purpose of these long vesting periods is to reinforce the long investment lead times in the business and to link a substantial portion of Mr. March s net worth to the performance of the company. During these vesting periods, the awards are subject to risk of forfeiture based on detrimental activity, or if Mr. March should leave the company before normal retirement.

The executive resources committee has determined that the overall compensation of Mr. March is appropriate based on the company s financial and operating performance and their assessment of his effectiveness in leading the organization. Key factors considered by the committee in determining his overall compensation level include continuing progress on advancing key strategic interests, financial results, safety metrics, environmental performance, government relations, productivity, cost effectiveness and asset management. The committee s decisions reflect judgment, taking all factors into consideration, rather than the application of formulas or targets. The higher level of pay for Mr. March, compared to the other named executive officers reflects his greater level of responsibility, including his ultimate responsibility for the performance of the company, and oversight of the other senior executives.

Pay Awarded to Other Named Executive Officers

Within the context of the compensation program structure and performance assessment processes described above, the value of 2008 incentive awards and salary adjustments align with:

- performance of the company;
- individual performance;
- long-term strategic plan of the business; and
- annual compensation of comparator companies.

The executive resources committee s decisions reflect judgment taking all factors into consideration, rather than application of formulae or targets. The executive resources committee approved the individual elements of compensation and the total compensation as shown in the summary compensation table on page 47.

Independent Consultant

In fulfilling its responsibilities during 2008, the executive resources committee retained one independent consultant to assist in determining compensation for senior executives. Towers Perrin provided an independent assessment of competitive chief executive officer compensation and of market data for long-term incentive compensation levels for senior executives to assist in the committee s assessment and decision-making on elements of compensation for B.H. March, as well as an assessment of the portion of senior executives pay attributable to long-term equity. Towers Perrin was not retained to provide any other compensation determinations or advice for the company or committee in determining the compensation of the chief executive officer or long-term incentive compensation levels for senior executives.

Performance Graph

The following graph shows changes over the past 10 years in the value of $100 invested in (1) Imperial Oil Limited common shares, (2) the S&P/TSX Composite Index, and (3) the S&P/TSX Equity Energy Index. The S&P/TSX Equity Energy Index is made up of share performance data for 37 oil and gas companies including integrated oil companies, oil and gas producers and oil and gas service companies.

The year-end values in the graph represent appreciation in share price and the value of dividends paid and reinvested. The calculations exclude trading commissions and taxes. Total shareholder returns from each investment, whether measured in dollars or percent, can be calculated from the year-end investment values shown beneath the graph.

During the past 10 years, the company s cumulative total shareholder return was about 582 percent, for an average annual return of about 19 percent. During that same 10-year period, the company s compensation (which compensation excludes the compensatory change in pension value) of its named executive officers increased by 223 percent for an average annual increase of eight percent.

(1) From 2002 to 2004, the S&P/TSX Composite Energy Index was used. Prior to 2002, the S&P/TSX Energy Index was used.

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Summary Compensation Table for Named Executive Officers

The following table shows the compensation for the chairman, president and chief executive officer; the senior vice-president, finance and administration, and treasurer and the three other most highly compensated executive officers of the company who were serving as at the end of 2008. The table includes information on T.J. Hearn, who also served as chairman and chief executive officer from January 1, 2008 to March 31, 2008, inclusive. This information includes the Canadian dollar value of base salaries, cash bonus awards and units of other long-term incentive compensation and certain other compensation.

Name and Principal Position at the end of 2008	Year	Salary ($)	Share-Based Awards ($) (2)	Option-Based Awards ($)(3)	Non-Equity Incentive Plan Compensation ($)		Pension Value ($) (6)	All Other Compensation ($) (7)	Total Compensation ($) (8)
					Annual Incentive Plans (4)	Long-term Incentive Plans (5)			
B.H. March (1) **President (January 1-March 31)** **Chairman, president and chief executive officer** **(April 1-December 31)**	2008	479,700	1,584,780	-	286,114	207,870	611,774	821,511	3,991,749
P.A. Smith **Senior vice-president, finance and administration, and treasurer**	2008	420,833	702,720	-	177,128	181,125	(13,100)	135,187	1,603,893
R.L Broiles (1) **Senior vice-president, resources division**	2008	398,418	915,918	-	186,443	169,494	254,286	506,051	2,430,610
C.W. Erickson (1) **Vice-president and general manager, refining and supply**	2008	394,864	999,183	-	196,144	187,147	234,192	413,604	2,425,134
S.M. Smith **Vice-president and general manager, fuels marketing**	2008	374,000	1,006,500	-	197,899	162,675	350,200	117,394	2,208,668
T.J. Hearn **Chairman and chief executive officer**	2008	300,000	-	-	-	999,900	124,200	719,049	2,143,149

(January 1-March 31)

(1) B.H. March, R.L. Broiles and C.W. Erickson have been on a loan assignment from Exxon Mobil Corporation since January 1, 2008, July 1, 2005 and June 1, 2007 respectively. Their compensation is paid directly by ExxonMobil Corporation in U.S. dollars, but is disclosed in Canadian dollars. They also receive employee benefits under Exxon Mobil Corporation s employee benefit plans, and not under the company s employee benefit plans. The company reimburses Exxon Mobil Corporation for the compensation paid and employee benefits provided to them. All amounts paid to B.H. March, R.L. Broiles and C.W. Erickson in U.S. dollars were converted to Canadian dollars at the average 2008 exchange rate of 1.066.

(2) The grant date fair value equals the number of restricted stock units multiplied by the closing price of the company s shares on the date of grant. The closing price of the company s shares on the grant date was $36.60, which is the same as the accounting fair value for the restricted stock units on the date of grant. The company chose this method of valuation as it believes it results in the most accurate representation of fair value. For R.L. Broiles and C.W. Erickson, who received ExxonMobil restricted stock units, values are based on the closing price of Exxon Mobil Corporation shares on the date of grant ($78.11 U.S.), multiplied by the number of units granted. This amount was converted to Canadian dollars at the average 2008 exchange rate of 1.066.

(3) The company has not granted stock options since 2002. The stock option plan is described on pages 49 through 50.

(4) The amounts listed in Annual Incentive Plans column for each named executive officer represent their 2008 cash bonus. Any part of bonus elected to be received as deferred share units would be excluded, although no named executive officers so elected.

(5) The amounts listed in Long-term Incentive Plans column for the named executive officer represents their earnings bonus units granted in 2007 and paid out in 2008. The plan is described on pages 39 through 40. B.H. March, R.L. Broiles and C.W. Erickson received earnings bonus units under ExxonMobil s program, which is similar to the company s plan. They also received pay outs in 2008 for earnings bonus units granted in 2007. These amounts were converted to Canadian dollars at the average 2008 exchange rate of 1.066.

(6) Pension Value is the compensatory change in pensions as of December 31, 2008, as set out in the pension plan benefits table on page 42.

(7) Amounts under All Other Compensation , consist of dividend equivalent payments on restricted stock units granted, interest paid in respect of deferred payments of bonuses and earnings bonus units, expatriate allowances, tax reimbursements, company savings

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plans contributions, other compensation and cost of perquisites including club memberships, earned benefit allowance (for T.J. Hearn, P.A. Smith and S.M. Smith only), any costs associated with the personal use of the company aircraft, parking and security. There is no tax assistance from the company for taxes related to personal use of the company aircraft. In 2008, only T.J. Hearn had interest paid in respect of deferred payments of bonuses and earnings bonus units which was $260,336. The earned benefits allowance in 2008 was $50,000 for T.J. Hearn, $30,000 for P.A. Smith and $25,000 for S.M. Smith. For each named executive officer, except B.H. March and T.J. Hearn, the aggregate value of perquisites received was not greater than $50,000. For B.H. March, the total value of perquisites was $58,898, which total includes club memberships valued at $41,974. For T.J. Hearn, the total value of perquisites was $67,862, which total includes an earned benefit allowance of $50,000. The 2008 annual vacation allowance payment of $120,000 for T.J. Hearn is also included under All Other Compensation . While already factored into valuation of share based awards, it is noted that in 2008, the actual dividend equivalent payments made were $70,550 for P.A. Smith, $56,124 for S.M. Smith and $261,470 for T.J. Hearn. For B.H. March, R.L. Broiles and C.W. Erickson, the dividend equivalent payments on restricted stock granted by Exxon Mobil Corporation in previous years were $83,028 for B.H. March, $80,137 for R.L. Broiles and $77,617 for C.W. Erickson. These amounts were converted to Canadian dollars at the average 2008 exchange rate of 1.066.

(8) Total Compensation for 2008 consists of the total dollar value of Salary , Share-Based Awards , Option-Based Awards , Non-Equity Incentive Plan Compensation , Pension Value and All Other Compensation .

Outstanding share-based awards and option-based awards for named executive officers

The following table sets forth all share-based and option-based awards outstanding as at December 31, 2008 for each of the named executive officers of the company.

	Option-based Awards				Share-based Awards	
Name	**Number of securities underlying unexercised options (#) (4)**	**Option exercise price ($)**	**Option Expiration Date**	**Value of unexercised in-the-money options ($)**	**Number of shares or units of shares that have not vested (#) (5)**	**Market or payout value of share-based awards that have not vested ($) (5)**
B.H. March (1)	-	-	-	-	43,300	1,774,867
P.A. Smith	75,000	15.50	April 29, 2012	1,911,750	181,850	7,454,032
R.L. Broiles (2)	-	-	-	-	-	-
C.W. Erickson (3)	-	-	-	-	-	-
S.M. Smith	-	-	-	-	158,900	6,513,311
T.J. Hearn (retired from the company on March 31, 2008)	150,000	15.50	April 29, 2012	3,823,500	618,200	25,340,018

(1) In 2001 and previous years, B.H. March participated in Exxon Mobil Corporation s stock option plan. Under that plan, B. H. March held options to acquire 44,758 Exxon Mobil Corporation shares, of which all options were exercisable. The value of B.H. March s exercisable options was $2,154,332 as at December 31, 2008, based on the closing price of Exxon Mobil Corporation common shares of $79.83 U.S., which was converted to Canadian dollars at the noon-rate for December 31, 2008 of 1.2246 provided by the Bank of Canada. B.H. March was granted restricted stock units in 2008 under the company s plan. With respect to previous years, B.H. March participated in Exxon Mobil Corporation s restricted stock plan, which is similar to the company s restricted stock unit plan. Under that plan, B. H. March held 44,750 restricted shares whose value on December 31, 2008 was $4,374,752 based on a closing price for Exxon Mobil Corporation shares on December 31, 2008 of $79.83 U.S., which was converted to Canadian dollars at the noon-rate for December 31, 2008 of 1.2246 provided by the Bank of Canada.

(2) In 2001 and previous years, R.L. Broiles participated in Exxon Mobil Corporation s stock option plan. Under that plan, R.L. Broiles held options to acquire 56,398 Exxon Mobil Corporation shares, of which all options were exercisable. The value of R.L. Broiles exercisable options was $2,687,938 as at December 31, 2008, based on the closing price of Exxon Mobil Corporation common shares of $79.83 U.S., which was converted to Canadian dollars at the noon-rate for December 31, 2008 of 1.2246 provided by the Bank of Canada. R.L. Broiles participates in Exxon Mobil Corporation s restricted stock plan, which is similar to the company s restricted stock unit plan. Under that plan, R.L. Broiles held 54,000 restricted shares whose value on December 31, 2008 was $5,279,030 based on a closing price for Exxon Mobil Corporation shares on December 31, 2008 of $79.83 U.S., which was converted to Canadian dollars at the noon-rate for

December 31, 2008 of 1.2246 provided by the Bank of Canada.

(3) In 2001 and previous years, C.W. Erickson participated in Exxon Mobil Corporation s stock option plan. Under that plan, C.W. Erickson held options to acquire 14,825 Exxon Mobil Corporation shares, of which all options were exercisable. The value of C.W. Erickson s exercisable options was $690,437 as at December 31, 2008, based on the closing price of Exxon Mobil Corporation common shares of $79.83 U.S., which was converted to Canadian dollars at the noon-rate for December 31, 2008 of 1.2246 provided by the Bank of Canada. C.W. Erickson participates in Exxon Mobil Corporation s restricted stock plan, which is similar to the company s restricted stock unit plan. Under that plan, C.W. Erickson holds 53,475 restricted shares whose value on December 31, 2008 was $5,227,706 based on a closing price for Exxon Mobil Corporation shares on December 31, 2008 of $79.83 U.S., which was converted to Canadian dollars at the noon-rate for December 31, 2008 of 1.2246 provided by the Bank of Canada.

(4) Represents the number of shares underlying options and three times the number of stock options granted in 2002 before the three-for-one share split in May 2006 and still held by the employee.

(5) Represents the total of the restricted stock units received in 2006, 2007 and 2008 after the three-for-one share split in May 2006, plus three times the number of restricted stock units received before the share split and still held by the employee. The value is based on the closing price of the company s shares on December 31, 2008 of $40.99.

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Incentive plan awards for named executive officers value vested or earned during the year

The following table sets forth the value of the incentive plan awards that vested for each named executive officer of the company for the year.

Name	Option-based awards Value vested during the year ($)	Share-based awards Value vested during the year ($) (4)	Non-equity incentive plan compensation Value earned during the year ($) (5)
B.H. March (1)	-	-	-
P.A. Smith	-	1,088,084	358,253
R.L. Broiles (2)	-	-	-
C.W. Erickson (3)	-	-	-
S.M. Smith	-	833,803	360,574
T.J. Hearn (retired from the company on March 31, 2008)	-	3,808,294	999,900

(1) Although B.H. March received restricted stock units under the company s plan in 2008, none of these restricted stock units have vested. In previous years B.H. March participated in Exxon Mobil Corporation s restricted stock plan under which the grantee may receive restricted stock or restricted stock units (both of which are referred to herein as restricted stock or restricted shares), which plan is similar to the company s restricted stock unit plan. In 2008, restrictions were removed on 5,500 restricted stock having a value as at December 31, 2008 of $537,679 based on the closing price of Exxon Mobil Corporation common shares of $79.83 U.S., which was converted to Canadian dollars at the noon-rate for December 31, 2008 of 1.2246 provided by the Bank of Canada. B.H. March received an annual bonus from Exxon Mobil Corporation in 2008 and participates in Exxon Mobil Corporation s earnings bonus unit plan, which is similar to the company s earnings bonus unit plan. B.H. March received $493,984 with respect to annual bonus awarded in 2008 and earnings bonus units granted in 2007 and paid out in 2008, which amount was paid in U.S. dollars and is converted to Canadian dollars at the average 2008 exchange rate of 1.066.

(2) R.L. Broiles participates in Exxon Mobil Corporation s restricted stock plan under which the grantee may receive restricted stock, which plan is similar to the company s restricted stock unit plan. In 2008, restrictions were removed on 5,500 restricted stock having a value as at December 31, 2008 of $537,679 based on the closing price of Exxon Mobil Corporation common shares of $79.83 U.S., which was converted to Canadian dollars at the noon-rate for December 31, 2008 of 1.2246 provided by the Bank of Canada. R.L. Broiles received an annual bonus from Exxon Mobil Corporation in 2008 and participates in Exxon Mobil Corporation s earnings bonus unit plan, which is similar to the company s earnings bonus unit plan. R.L. Broiles received $355,937 with respect to annual bonus awarded in 2008 and earnings bonus units granted in 2007 and paid out in 2008, which amount was paid in U.S. dollars and is converted to Canadian dollars at the average 2008 exchange rate of 1.066.

(3) C.W. Erickson participates in Exxon Mobil Corporation s restricted stock plan under which the grantee may receive restricted stock, which plan is similar to the company s restricted stock unit plan. In 2008, restrictions were removed on 5,500 restricted stock having a value as at December 31, 2008 of $537,679 based on the closing price of Exxon Mobil Corporation common shares of $79.83 U.S., which was converted to Canadian dollars at the noon-rate for December 31, 2008 of 1.2246 provided by the Bank of Canada. C.W. Erickson received an annual bonus from Exxon Mobil Corporation in 2008 and participates in Exxon Mobil Corporation s earnings bonus unit plan, which is similar to the company s earnings bonus unit plan. C.W. Erickson received $383,291 with respect to annual bonus awarded in 2008 and earnings bonus units granted in 2007 and paid out in 2008, which amount was paid in U.S. dollars and is converted to Canadian dollars at the average 2008 exchange rate of 1.066.

(4) These values show restricted stock units that vested in 2008.

(5) These values show annual bonus received in 2008 and earnings bonus units granted in 2007 and vesting in 2008.

Details of Former Long-Term Incentive Compensation Plans

The following describes forms of long-term incentive compensation formerly used by the company. While incentive share units and stock options are no longer granted, incentive share units and stock options formerly granted continue to remain outstanding and are referenced in the foregoing tables.

Incentive Share Units

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 executives 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.

Stock Option Plan

Under the stock option plan adopted by the company in April 2002, a total of 9,630,600 options, on a post share split basis, were granted to selected key employees on April 30, 2002 for the purchase of the company s common shares at an exercise price of $15.50 per share on a post share split basis. All of the options are exercisable. Any unexercised options expire on April 29, 2012. As of February 13, 2009, there have been 5,336,415 common shares issued upon exercise of stock options and 4,294,185 common shares are issuable upon future exercise of stock options. The common shares that were issued and those that may be issued in the future represent about 1.1 percent of the company s currently outstanding common shares. The company s directors, officers and vice-presidents as a group hold eight percent of the unexercised stock options.

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The maximum number of common shares that any one person may receive from the exercise of stock options is 150,000 common shares, which is about 0.02 percent of the currently outstanding common shares. Stock options may be exercised only during employment with the company except in the event of death, disability or retirement. Also, stock options may be forfeited if the company believes that the employee intends to terminate employment or if during employment or during the period of 24 months after the termination of employment the employee, without the consent of the company, engaged in any business that was in competition with the company or otherwise engaged in any activity that was detrimental to the company. The company may determine that stock options will not be forfeited after the cessation of employment. Stock options cannot be assigned except in the case of death.

The company may amend or terminate the incentive stock option plan as it in its sole discretion determines appropriate. No such amendment or termination can be made to impair any rights of stock option holders under the incentive stock option plan unless the stock option holder consents, except in the event of (a) any adjustments to the share capital of the company or (b) a take-over bid, amalgamation, combination, merger or other reorganization, sale or lease of assets, or any liquidation, dissolution, or winding-up, involving the company. Appropriate adjustments may be made by the company to: (i) the number of common shares that may be acquired on the exercise of outstanding stock options; (ii) the exercise price of outstanding stock options; or (iii) the class of shares that may be acquired in place of common shares on the exercise of outstanding stock options in order to preserve proportionately the rights of the stock option holders and give proper effect to the event.

Directors Compensation

Director compensation elements are designed to:

- ensure alignment with long-term shareholder interests;
- provide motivation to promote sustained improvement in the company s business performance and shareholder value;
- ensure the company can attract and retain outstanding director candidates who meet the selection criteria outlined in Section 9 of the board of directors charter;
- recognize the substantial time commitments necessary to oversee the affairs of the company; and
- support the independence of thought and action expected of directors.

Nonemployee director compensation levels are reviewed by the nominations and corporate governance committee each year, and resulting recommendations are presented to the full board for approval.

Employees of the company or ExxonMobil receive no extra pay for serving as directors. Nonemployee directors receive compensation consisting of cash and restricted stock units. Since 1999, the nonemployee directors have been able to receive all or part of their cash directors fees in the form of deferred share units. The purpose of the deferred share unit plan for nonemployee directors is to provide them with additional motivation to promote sustained improvement in the company s business performance and shareholder value by allowing them to have all or part of their directors fees tied to the future growth in value of the company s common shares. The number of units granted to a nonemployee director is determined at the end of each calendar quarter by dividing the amount of the directors fees for that calendar quarter that the nonemployee director elected to receive as deferred share units by the average closing price immediately prior to the last day of the calendar quarter. The deferred share unit plan is described in more detail on pages 41 through 42.

In 2008, the base cash retainer for nonemployee directors was $100,000 per year. Nonemployee directors were paid $20,000 for membership on all board committees. Additionally, each board committee chair received a retainer of $10,000 for each committee chaired. Nonemployee directors were not paid a fee for attending board and committee meetings on each of the eight regularly-scheduled meeting days. However, they were eligible to receive a fee of $2,000 per board or committee meeting occurring on any other day. Four board and committee meetings occurred outside the eight regularly scheduled meeting days.

The following table shows the portion of the annual retainer for board membership, annual retainer for committee membership and annual retainer for committee chair which each nonemployee director elected to receive in cash and deferred share units in 2008.

	Election for 2008 Director	Election for 2008 Director Fees

	Fees in Cash	**in Deferred Share Units**
	(%)	**(%)**
K.T. Hoeg (Director since May 1, 2008)	-	100
J.M. Mintz	50	50
R. Phillips	-	100
J.F. Shepard (Director until May 1, 2008)	-	100
S.D. Whittaker	-	100
V.L. Young	75	25

50

In addition to the cash fees described above, the company pays a significant portion of director compensation in restricted stock units to align director compensation with the long-term interests of shareholders. Restricted stock units are awarded annually with 50 percent vesting in cash three years from the date of grant and the remaining 50 percent vesting on the seventh anniversary of the grant date. Directors can elect to receive one common share for each unit or a cash payment for the units to be exercised on the seventh anniversary date of the date of grant of the restricted stock units. The vesting periods are not accelerated upon separation or retirement from the board, except in the event of death. The restricted stock unit plan is described in more detail on pages 40 through 41. In 2008, each nonemployee director received an annual grant of 2,000 restricted stock units.

Components of Directors Compensation

Director	Annual Retainer for Board Membership ($)	Annual Retainer for Committee Membership ($)	Annual Retainer for Committee Chair ($)	Restricted Stock Units (RSU) (#)	Fee for Board and Committee Meetings Not Regularly Scheduled		Total Cash ($) (1)	Total Deferred Share Units (DSU) ($) (2)	Total Restricted Stock Units ($) (3)	Total Compensation ($)
					Number of non-regularly scheduled meetings attended (#)	Fee ($2,000 x number of meetings attended) ($)				
K.T. Hoeg (Director since May 1, 2008)	66,944	13,388 (IOF)	6,694	2,000	-	-	-	87,027	73,200	160,227
J.M. Mintz	100,000	20,000 (EH&S)	10,000	2,000	2	4,000	69,000	65,000	73,200	207,200
R. Phillips	100,000	20,000 (ERC)	10,000	2,000	2	4,000	4,000	130,000	73,200	207,200
J.F. Shepard (Director until May 1, 2008)	33,611	6,722 (AC)	3,361	-	2	4,000	4,000	43,694	-	47,694
S.D. Whittaker	100,000	20,000 (N&CG)	10,000	2,000	4	8,000	8,000	130,000	73,200	211,200
V.L. Young	100,000	20,000 (AC)	10,000	2,000	4	8,000	105,500	32,500	73,200	211,200

(1) Total Cash is the portion of the annual retainer for board membership, annual retainer for committee membership and annual retainer for committee chair which the director elected to receive as cash, plus the fee for board and committee meetings not regularly scheduled. This amount is reported as Fees Earned in the Director Compensation Table on page 52.

(2) Total Deferred Share Units is the portion of the annual retainer for board membership, annual retainer for committee membership and annual retainer for committee chair, which the director elected to receive as deferred share units, as set out in the previous table on page 50. This amount plus the total restricted stock units amount is shown as Share-based Awards in the Director Compensation Table on page 52.

(3) The values of the restricted stock units shown are the number of units multiplied by the closing price of the company s shares on the date of grant.

On November 20, 2008, the board amended the restricted stock unit plan to provide that the board will no longer have the general discretion to cancel restricted stock units awarded to a nonemployee director subsequent to leaving the company s board. Previously, the board had to approve the retention of restricted stock units when the nonemployee director left the board. The objective of this language was to encourage board members to remain on the board until standard retirement time, thereby ensuring board member alignment with long-term shareholder value. It has been determined by the board that, to reinforce the independence of each board member, this provision of the incentive plan language for nonemployee directors would be removed. This change applies to the terms of all outstanding restricted stock units and any restricted stock unit grants going forward. However, while on the board and for a 24-month period after leaving the company s board, restricted stock units may be forfeited if the nonemployee director engages in direct competition with the company or otherwise engages in any activity detrimental to the company. The board agreed that the word detrimental shall not include any actions taken by a nonemployee director or former nonemployee director who acted in good faith and in the best interests of the company.

Compensation Decision Making Process and Considerations

The nominations and corporate governance committee relies on market comparisons with a group of 21 major Canadian companies with national and international scope and complexity. The company draws its non-employee directors from a wide variety of industrial sectors, so a broad sample is appropriate for this purpose. The nominations and corporate governance committee does not target any specific percentile among comparator companies at which to align compensation for this group, but rather considers current developments and practices in director

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compensation elements based on analysis of published management proxy circulars completed every two years. The 21 comparator companies included in the benchmark sample are as follows:

Comparator Companies Non-Employee Directors

Alcan Inc.	EnCana Corporation	Bank of Nova Scotia
Bank of Montreal	George Weston Limited	Sun Life Financial Inc.
BCE Inc.	Manulife Financial Corporation	Suncor Energy Inc.
Bombardier Inc.	Nortel Networks Corporation	TELUS Corporation
Canadian Imperial Bank of Commerce	Petro-Canada	Thomson Reuters Corporation
Canadian National Railway Company	Power Financial Corporation	The Toronto Dominion Bank
Canadian Pacific Railway Limited	Royal Bank of Canada	TransCanada Corporation

Director Compensation Table

The following table summarizes the compensation paid, payable, awarded or granted for 2008 to each of the independent directors of the company.

Name (1)	Fees Earned ($) (3)	Share-based awards ($) (4)	Option-based awards ($)	Non-equity incentive plan compensation ($)	Pension value (#)	All other compensation ($)	Total ($)
K.T. Hoeg (2) (Director since May 1, 2008)	-	160,227	-	-	-	-	160,227
J.M. Mintz (2)	69,000	138,200	-	-	-	-	207,200
R. Phillips (2)	4,000	203,200	-	-	-	-	207,200
J.F. Shepard (2) (Director until May 1, 2008)	4,000	43,694	-	-	-	-	47,694
S.D. Whittaker (2)	8,000	203,200	-	-	-	-	211,200
V.L. Young (2)	105,500	105,700	-	-	-	-	211,200

(1) As directors employed by the company or Exxon Mobil Corporation, T.J. Hearn, B.H. March, R.L. Broiles, P.A. Smith and R.C. Olsen did not receive compensation for acting as directors.
(2) Starting in 1999, the nonemployee directors have been able to receive all or part of their directors fees in the form of deferred share units.
(3) Represents all fees awarded, earned, paid or payable in cash for services as a director, including retainer fees, committee, chair and meeting fees.
(4) The values of the restricted stock units and the deferred share units shown are the number of units multiplied by the closing price of the company s shares on the date of grant. The dollar value of deferred share units shown is the value of the portion of the annual retainer for board membership, annual retainer for committee membership, and annual retainer for committee chair, which the director elected to receive as deferred share units as noted on pages 50 and 51.

Outstanding share-based awards and option-based awards for directors

The following table sets forth all outstanding awards held by independent directors of the company as at December 31, 2008.

Option-based Awards	Share-based Awards

Name (1)	**Number of securities underlying unexercised options (#)**	**Option exercise price ($)**	**Option Expiration Date**	**Value of unexercised in-the-money options ($)**	**Number of shares or units of shares that have not vested (#) (2)**	**Market or payout value of share-based awards that have not vested ($) (3)**
K.T. Hoeg (Director since May 1, 2008)	-	-	-	-	3,931	161,131
J.M. Mintz	-	-	-	-	11,563	473,967
R. Phillips	-	-	-	-	30,361	1,244,497
J.F. Shepard (Director until May 1, 2008)	-	-	-	-	10,625	435,519
S.D. Whittaker	-	-	-	-	46,051	1,887,630
V.L. Young	-	-	-	-	18,668	765,201

(1) As directors employed by the company or Exxon Mobil Corporation, T.J. Hearn, B.H. March, R.L. Broiles, P.A. Smith and R.C. Olsen did not receive compensation for acting as directors.
(2) Includes restricted stock units and deferred share units held as of December 31, 2008.
(3) Value is based on the closing price of the company s shares on December 31, 2008.

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Incentive plan awards for directors value vested or earned during the year

The following table sets forth the value of the awards that vested or were earned by each independent director of the company in 2008.

Name (1)	Option-based awards Value vested during the year ($)	Share-based awards Value vested during the year ($)	Non-equity incentive plan compensation Value earned during the year ($)
K.T. Hoeg (Director since May 1, 2008)	-	-	-
J.M. Mintz (2)	-	59,135	-
R. Phillips (2)	-	59,135	-
J.F. Shepard (2)(3) (Director until May 1, 2008)	-	1,443,396	-
S.D. Whittaker (2)	-	59,135	-
V.L. Young (2)	-	59,135	-

(1) As directors employed by the company or Exxon Mobil Corporation, T.J. Hearn, B.H. March, R.L. Broiles, P.A. Smith and R.C. Olsen did not receive compensation for acting as directors.
(2) Includes restricted stock units granted in 2005 and vesting in 2008.
(3) For J.F. Shepard, the value includes deferred share units that vested as of his retirement date from the board on May 1, 2008.

Share Ownership Guidelines for Directors

Directors are required to hold the equivalent of at least 15,000 shares of Imperial Oil Limited, including common shares, deferred share units and restricted stock units. Directors are expected to reach this level within five years. The board of directors believes that the share ownership guideline will result in an alignment of the interest of board members with the interests of all other shareholders.

Director	Director Since	Amount acquired since last report (February 15, 2008 to February 13, 2009)	Total Holdings (includes common shares, deferred share units and restricted stock units)	Minimum Requirement	Minimum Requirement Achieved	Date Required to Achieve Minimum Requirement
K.T. Hoeg	May 1, 2008	3,931	3,931	15,000	No	May 1, 2013
B.H. March (1)	January 1, 2008	43,300	48,300	15,000	Yes	January 1, 2013
J.M. Mintz	April 21, 2005	1,879	12,563	15,000	No	April 21, 2010
R.C. Olsen	May 1, 2008	3,000	3,000	15,000	No	May 1, 2013

R. Phillips	April 23, 2002	3,349	39,361	15,000	Yes	April 23, 2007
P.A. Smith	February 1, 2002	(8,678)	194,909	15,000	Yes	February 1, 2007
S.D. Whittaker	April 19, 1996	3,474	55,051	15,000	Yes	April 19, 2001
V.L. Young	April 23, 2002	2,223	29,918	15,000	Yes	April 23, 2007

(1) Paragraph 10(b) of the Board of Directors Charter provides that B.H. March, as chairman, president and chief executive officer shall, within three years of his appointment as chairman and chief executive officer, acquire shares of the company, including common shares, deferred share units and restricted stock units, of a value of no less than five times his base salary. B.H. March has not yet achieved this requirement.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

To the knowledge of the directors and executive officers of the company, the only shareholder who, as of February 13, 2009, owned beneficially, or exercised control or direction over, directly or indirectly, more than 10 percent of the outstanding common shares of the company is Exxon Mobil Corporation, 5959 Las Colinas Boulevard, Irving, Texas 75039-2298, which owns beneficially 596,357,122 common shares, representing 69.6 percent of the outstanding voting shares of the company.

Reference is made to the security ownership information under the preceding Items 10 and 11. As of February 13, 2009, S.M. Smith was the owner of 3,794 common shares of the company and held 158,900 restricted stock units of the company.

The executive officers and the directors of the company, whose compensation for the year ended December 31, 2008 is described on pages 37 through 53, consist of 15 persons, who, as a group, own beneficially 71,991 common shares of the company, being approximately 0.01 percent of the total number of outstanding shares of the company, and 515,218 shares of Exxon Mobil Corporation (including 334,805 restricted shares). This information

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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 145,500 common shares of the company and held restricted stock units to acquire 504,925 common shares of the company, as of February 13, 2009.

Equity Compensation Plan Information

The following table provides information on the common shares of the company that may be issued as of the end of 2008 pursuant to compensation plans of the company.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (3)	Weighted-average exercise price of outstanding options warrants, and rights ($) (4)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in the first column) (3)
Equity compensation plans approved by security holders (1)	4,294,635	15.50	-
Equity compensation plans not approved by security holders (2)	7,928,818	-	2,571,182
Total	12,223,453	15.50	2,571,182

(1) This is a stock option plan, which is described on pages 49 through 50.
(2) This is a restricted stock unit plan, which is described on pages 40 through 41.
(3) The number of securities reserved for the stock option plan represents three times the number of stock options granted in 2002 before the three-for-one share split in May 2006 and still outstanding. The number of securities reserved for the restricted stock unit plan represents the securities reserved for restricted stock units issued in 2006, 2007 and 2008 after the three-for-one share split in May 2006, plus three times the number of securities reserved for restricted stock units issued before the share split and still outstanding.
(4) The weighted average exercise price of the outstanding stock options of $15.50 was determined on a post share split basis.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

On June 25, 2007, the company implemented a 12-month normal course share-purchase program under which it purchased 45,794,291 of its outstanding shares between June 25, 2007 and June 24, 2008. On June 25, 2008, a 12-month share purchase program was implemented under which the company may purchase up to 44,194,961 of its outstanding shares, less any shares purchased by the employee savings plan and company pension fund. Exxon Mobil Corporation participated by selling shares to maintain its ownership at 69.6 percent. In 2008, such share purchases cost about $2,210 million, of which about $1,521 million was received by Exxon Mobil Corporation.

The amounts of purchases and sales by the company and its subsidiaries for other transactions in 2008 with Exxon Mobil Corporation and affiliates of Exxon Mobil Corporation were $4,890 million and $2,150 million, respectively. These transactions 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, natural gas, petroleum and chemical products, as well as transportation, technical and engineering services. Transactions with Exxon Mobil Corporation also included amounts paid and received in connection with the company s participation in a number of upstream activities conducted jointly in Canada. The company also has agreements with affiliates of Exxon Mobil Corporation to provide computer and customer support services to the company and to share common business and operational support services to allow the companies to consolidate duplicate work and systems. The company has a contractual agreement with an affiliate of Exxon Mobil Corporation in Canada to operate the Western Canada production properties owned by ExxonMobil. There are no asset ownership changes. The company and that affiliate also have a contractual agreement to share new upstream opportunities on an up to equal basis. During 2007, the company entered into agreements with Exxon Mobil Corporation and one of its affiliated companies that provide for the delivery of management, business and technical services to Syncrude Canada Ltd. by

ExxonMobil.

R.C. Olsen is a non-independent member of the executive resources committee, environmental, health and safety committee and nominations and corporate governance committee. 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.

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Item 14. Principal Accountant Fees and Services.
Auditor Fees

The aggregate fees of the company s auditor PricewaterhouseCoopers LLP (PwC) for professional services rendered for the audit of the company s financial statements and other services for the fiscal years ended December 31, 2008 and December 31, 2007 were as follows:

Dollars (thousands)	**2008**	**2007**
Audit Fees	**1,140**	1,117
Audit-Related Fees	**62**	62
Tax Fees	**176**	942
All Other Fees	**-**	-
Total Fees	**1,378**	2,121

Audit fees include the audit of the company s annual financial statements and internal control over financial reporting, and a review of the first three quarterly financial statements in 2008. Audit-related fees include other assurance services including the audit of the company s retirement plan and royalty statement audits for oil and gas producing entities. Tax fees are mainly tax services for employees on foreign loan assignments. 2008 was the final year of PwC providing tax services for the company s employees on foreign loan assignment. The company did not engage the auditor for any other services.

The audit committee recommends the external auditor to be appointed by the shareholders, fixes its remuneration and oversees its work. The audit committee also approves the proposed current year audit program of the external auditor, assesses the results of the program after the end of the program period and approves in advance any non-audit services to be performed by the external auditor after considering the effect of such services on their independence.

All of the services rendered by the auditor to the company were approved by the audit committee.

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PART IV

Item 15. Exhibits and Financial Statement Schedules.
Reference is made to the Index to Financial Statements on page F-1 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)).

(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)).

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(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

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(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).

(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 effective November 20, 2008 (Filed as Exhibit 15(10)(iii)(A)(25) to this Form 10-K).

(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, 2006.

(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 24, 2009 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 24, 2009 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 A. Smith	Senior Vice-President,
(Paul A. Smith)	Finance and Administration, and Treasurer
	and Director
	(Principal Accounting Officer and
	Principal 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/ Roger Phillips	Director
(Roger Phillips)	
/s/ Sheelagh D. Whittaker	Director

(Sheelagh D. Whittaker)

/s/ Victor L. Young	Director
(Victor L. Young)	

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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 the *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Imperial Oil Limited s internal control over financial reporting was effective as of December 31, 2008.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the company s internal control over financial reporting as of December 31, 2008, as stated in their report which is included herein.

/s/ Bruce H. March
Bruce H. March
Chairman, president and chief executive officer

/s/ Paul A. Smith
Paul A. Smith
Senior vice-president, finance and administration, and treasurer (Principal accounting officer and principal financial officer)

AUDITORS REPORT

To the Shareholders of Imperial Oil Limited

We have completed integrated audits of Imperial Oil Limited s 2008, 2007 and 2006 consolidated financial statements and of its internal control over financial reporting as of December 31, 2008. Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of Imperial Oil Limited and its subsidiaries at December 31, 2008 and December 31, 2007, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

Internal control over financial reporting

Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s report on internal control over financial reporting. Our responsibility is to express an opinion on the effectiveness of the Company s internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

/s/ PricewaterhouseCoopers LLP
Chartered Accountants

Calgary, Alberta, Canada

February 24, 2009

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Consolidated statement of income (U.S. GAAP)

millions of Canadian dollars For the years ended December 31	**2008**	2007	2006
Revenues and other income			
Operating revenues (a)(b)	**31 240**	25 069	24 505
Investment and other income (note 9)	**339**	374	283
Total revenues and other income	**31 579**	25 443	24 788
Expenses			
Exploration	**132**	106	32
Purchases of crude oil and products (c)	**18 865**	14 026	13 793
Production and manufacturing (d)	**4 228**	3 474	3 446
Selling and general	**1 038**	1 335	1 284
Federal excise tax (a)	**1 312**	1 307	1 274
Depreciation and depletion	**728**	780	831
Financing costs (note 13)	**-**	36	28
Total expenses	**26 303**	21 064	20 688
Income before income taxes	**5 276**	4 379	4 100
Income taxes (note 4)	**1 398**	1 191	1 056
Net income	**3 878**	3 188	3 044
Per-share information (Canadian dollars)			
Net income per common share - basic (note 11)	**4.39**	3.43	3.12
Net income per common share - diluted (note 11)	**4.36**	3.41	3.11
Dividends	**0.38**	0.35	0.32

(a) Operating revenues include federal excise tax of $1,312 million (2007 - $1,307 million, 2006 - $1,274 million,).
(b) Operating revenues include amounts from related parties of $2,150 million (2007 - $1,772 million, 2006 - $1,955 million), (note 15).
(c) Purchases of crude oil and products include amounts from related parties of $4,729 million (2007 - $3,331 million, 2006 - $3,937 million), (note 15).
(d) Production and manufacturing expenses include amounts to related parties of $161 million (2007 - $194 million, 2006 - $156 million), (note 15).

The information on pages F-7 through F-20 is an integral part of these consolidated financial statements.

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Consolidated balance sheet (U.S. GAAP)

millions of Canadian dollars

At December 31	2008	2007
Assets		
Current assets		
Cash	**1 974**	1 208
Accounts receivable, less estimated doubtful amounts	**1 455**	2 132
Inventories of crude oil and products (note 12)	**673**	566
Materials, supplies and prepaid expenses	**180**	128
Deferred income tax assets (note 4)	**361**	660
Total current assets	**4 643**	4 694
Long-term receivables, investments and other long-term assets	**881**	766
Property, plant and equipment, less accumulated depreciation and depletion (note 3)	**11 248**	10 561
Goodwill (note 3)	**204**	204
Other intangible assets, net	**59**	62
Total assets (note 3)	**17 035**	16 287
Liabilities		
Current liabilities		
Notes and loans payable (note 13)	**109**	108
Accounts payable and accrued liabilities (a)	**2 542**	3 335
Income taxes payable	**1 498**	1 498
Total current liabilities	**4 149**	4 941
Capitalized lease obligations (note 14)	**34**	38
Other long-term obligations (note 6)	**2 298**	1 914
Deferred income tax liabilities (note 4)	**1 489**	1 471
Total liabilities	**7 970**	8 364
Commitments and contingent liabilities (note 10)		
Shareholders equity		
Common shares at stated value (note 11)(b)	**1 528**	1 600
Earnings reinvested	**8 484**	7 071
Accumulated other comprehensive income	**(947)**	(748)
Total shareholders equity	**9 065**	7 923
Total liabilities and shareholders equity	**17 035**	16 287

(a) Accounts payable and accrued liabilities include amounts to related parties of $96 million (2007 - $260 million), (note 15).
(b) Number of common shares outstanding was 859 million (2007 - 903 million), (note 11).
The information on pages F-7 through F-20 is an integral part of these consolidated financial statements.

Approved by the directors

/s/ B.H. March
Chairman, president and
chief executive officer

/s/ P.A. Smith
Senior vice-president,
finance and administration, and treasurer

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

millions of Canadian dollars At December 31	**2008**	2007	2006
Common shares at stated value (note 11)			
At beginning of year	**1 600**	1 677	1 747
Issued under the stock option plan	**7**	12	10
Share purchases at stated value	**(79)**	(89)	(80)
At end of year	**1 528**	1 600	1 677
Earnings reinvested			
At beginning of year	**7 071**	6 462	5 466
Cumulative effect of accounting change (note 4)	**-**	14	-
Net income for the year	**3 878**	3 188	3 044
Share purchases in excess of stated value	**(2 131)**	(2 269)	(1 737)
Dividends	**(334)**	(324)	(311)
At end of year	**8 484**	7 071	6 462
Accumulated other comprehensive income			
At beginning of year	**(748)**	(733)	(580)
Post-retirement benefits liability adjustment (note 5)	**(283)**	(87)	(733)
Amortization of post-retirement benefits liability adjustment included in net periodic benefit cost	**84**	72	-
Minimum pension liability adjustment (note 5)	**-**	-	580
At end of year	**(947)**	(748)	(733)
Shareholders equity at end of year	**9 065**	7 923	7 406
Comprehensive income for the year			
Net income for the year	**3 878**	3 188	3 044
Other comprehensive income			
Post-retirement benefits liability adjustment	**(199)**	(15)	-
Minimum pension liability adjustment	**-**	-	334
Total comprehensive income for the year	**3 679**	3 173	3 378

The information on pages F-7 through F-20 is an integral part of these consolidated financial 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	**2008**	2007	2006
Operating activities			
Net income	**3 878**	3 188	3 044
Adjustments for non-cash items:			
Depreciation and depletion	**728**	780	831
(Gain)/loss on asset sales	**(241)**	(215)	(134)
Deferred income taxes and other	**387**	75	292
Changes in operating assets and liabilities:			
Accounts receivable	**679**	(261)	203
Inventories and prepaids	**(159)**	13	(97)
Income taxes payable	**-**	(77)	(225)
Accounts payable	**(798)**	250	(86)
All other items - net (a)	**(211)**	(127)	(241)
Cash from operating activities	**4 263**	3 626	3 587
Investing activities			
Additions to property, plant and equipment and intangibles	**(1 231)**	(899)	(1 177)
Proceeds from asset sales	**272**	279	212
Loans to equity company	**(2)**	-	-
Cash from (used in) investing activities	**(961)**	(620)	(965)
Financing activities			
Short-term debt - net	**-**	(65)	72
Repayment of long-term debt	**-**	(1 722)	(70)
Long-term debt issued	**-**	500	-
Reduction in capitalized lease obligations	**(3)**	(4)	(4)
Issuance of common shares under stock option plan	**7**	12	10
Common shares purchased (note 11)	**(2 210)**	(2 358)	(1 818)
Dividends paid	**(330)**	(319)	(315)
Cash from (used in) financing activities	**(2 536)**	(3 956)	(2 125)
Increase (decrease) in cash	**766**	(950)	497
Cash at beginning of year	**1 208**	2 158	1 661
Cash at end of year (b)	**1 974**	1 208	2 158

(a) Includes contribution to registered pension plans of $165 million (2007 - $163 million, 2006 - $395 million).
(b) Cash is composed of cash in bank and cash equivalents at cost. Cash equivalents are all highly liquid securities with maturity of three months or less when purchased.

The information on pages F-7 through F-20 is an integral part of these consolidated financial 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 2008 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.

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. 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. Costs of productive wells and development dry holes are capitalized and amortized on the unit-of-production method for each field. The company uses this accounting policy instead of the full-cost method because it provides a more timely accounting of the success or failure of the company s exploration and production activities.

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

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

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

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

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

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

Depreciation of oil sands mining and extraction assets begins when bitumen ore is produced on a sustained basis, and depreciation of bitumen upgrading assets begins when feed is introduced to the upgrading unit and maintained on a continuous basis. Assets under construction are not depreciated. Investments in extraction facilities, which separate the crude from sand, as well as the upgrading facilities, are depreciated on a unit-of-production method based on proven reserves. Investments in mining and transportation systems are generally depreciated on a straight-line basis over a 15-year life. Other mining related infrastructure costs that are of a long-term nature intended for continued use in or to provide long-term benefit to the operation, such as pre-production stripping, certain roads, etc., are depreciated on a unit-of-production basis based on proven reserves.

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

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

[a] Oil sands are a semi-solid material composed of bitumen, sand, water and clays and are recovered through surface mining methods. Currently, the company s oil sands production volumes are the company s share of production volumes in the Syncrude joint venture, and the company s reserves from oil sands operations are the company s share of synthetic crude oil reserves in the Syncrude joint venture and the company s share of mined bitumen reserves in the Kearl oil sands project.

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 remediation and decommissioning and removal costs of oil and gas wells and related facilities. The obligations are initially measured at fair value and discounted to present value. A corresponding amount equal to that of the initial obligation is added to the capitalized costs of the related asset. Over time, the discounted asset retirement obligation amount will be accreted for the change in its present value, and the initial capitalized costs will be depreciated over the useful lives of the related assets.

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

Foreign-currency translation

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

Financial instruments

The fair values of cash, accounts receivable and current liabilities approximate recorded amounts because of the short period to receipt or payment of cash. The fair values of the company s other financial instruments, which are mainly long-term receivables, are estimated primarily by discounting future cash flows, using current rates for similar financial instruments under similar credit risk and maturity conditions.

The company does not use financing structures for the purpose of altering accounting outcomes or removing debt from the balance sheet. The company does not use derivative instruments to speculate on the future direction of currency or commodity prices.

Revenues

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

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

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 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 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 and the federal goods and services tax.

2. Accounting change for fair value measurement

Effective January 1, 2008, the company adopted the Financial Accounting Standards Board s (FASB) Statement No. 157 (SFAS 157), Fair Value Measurements for financial assets and liabilities that are measured at fair value and nonfinancial assets and liabilities that are remeasured at fair value on a recurring basis. SFAS 157 defines fair value, establishes a framework for measuring fair value when an entity is required to use a fair value measure for recognition or disclosure purposes and expands the disclosures about fair value measurements. The initial application of SFAS 157 had no material impact on the company s financial statements. Effective January 1, 2009, SFAS 157 is applicable to all nonfinancial assets and liabilities that are measured at fair value.

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, 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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millions of dollars	Upstream (a) 2008	2007	2006	Downstream 2008	2007	2006	Chemical 2008	2007	2006
Revenues and other income									
External sales (b)	**5 819**	4 539	4 619	**24 049**	19 230	18 527	**1 372**	1 300	1 359
Intersegment sales	**5 403**	4 146	3 837	**2 892**	2 305	2 256	**460**	335	345
Investment and other income	**18**	233	111	**271**	52	105	**1**	-	-
	11 240	8 918	8 567	**27 212**	21 587	20 888	**1 833**	1 635	1 704
Expenses									
Exploration	**132**	106	32	**-**	-	-	**-**	-	-
Purchases of crude oil and products	**3 995**	3 113	2 841	**22 223**	16 469	16 178	**1 401**	1 230	1 209
Production and manufacturing	**2 569**	2 057	1 994	**1 452**	1 232	1 266	**208**	185	189
Selling and general (c)	**6**	8	13	**998**	987	1 018	**72**	71	76
Federal excise tax	**-**	-	-	**1 312**	1 307	1 274	**-**	-	-
Depreciation and depletion	**474**	519	584	**234**	244	233	**12**	12	11
Financing costs (note 13)	**2**	4	2	**(5)**	1	6	**-**	-	-
Total expenses	**7 178**	5 807	5 466	**26 214**	20 240	19 975	**1 693**	1 498	1 485
Income before income taxes	**4 062**	3 111	3 101	**998**	1 347	913	**140**	137	219
Income taxes (note 4)									
Current	**1 051**	682	602	**(56)**	491	174	**37**	42	60
Deferred	**88**	60	123	**258**	(65)	115	**3**	(2)	16
Total income tax expense	**1 139**	742	725	**202**	426	289	**40**	40	76
Net income	**2 923**	2 369	2 376	**796**	921	624	**100**	97	143
Cash flow from (used in) operating activities	**3 699**	2 411	3 024	**280**	1 151	507	**183**	109	161
Capital and exploration expenditures	**1 110**	744	787	**232**	187	361	**13**	11	13
Property, plant and equipment									
Cost	**16 344**	15 285	14 926	**6 776**	6 655	6 581	**732**	718	702
Accumulated depreciation and depletion	**(8 832)**	(8 474)	(8 255)	**(3 452)**	(3 320)	(3 178)	**(514)**	(496)	(484)
Net property, plant and equipment (d)(e)	**7 512**	6 811	6 671	**3 324**	3 335	3 403	**218**	222	218
Total assets	**8 758**	8 171	7 513	**6 038**	6 727	6 450	**431**	476	504

millions of dollars	Corporate and other 2008	2007	2006	Eliminations 2008	2007	2006	Consolidated 2008	2007	2006
Revenues and other income									
External sales (b)	**-**	-	-	**-**	-	-	**31 240**	25 069	24 505
Intersegment sales	**-**	-	-	**(8 755)**	(6 786)	(6 438)	**-**	-	-
Investment and other income	**49**	89	67	**-**	-	-	**339**	374	283
	49	89	67	**(8 755)**	(6 786)	(6 438)	**31 579**	25 443	24 788
Expenses									
Exploration	**-**	-	-	**-**	**-**	**-**	**132**	106	32
Purchases of crude oil and products	**-**	-	-	**(8 754)**	(6 786)	(6 435)	**18 865**	14 026	13 793
Production and manufacturing	**-**	-	-	**(1)**	-	(3)	**4 228**	3 474	3 446
Selling and general (c)	**(38)**	269	177	**-**	-	-	**1 038**	1 335	1 284
Federal excise tax				**-**	-	-	**1 312**	1 307	1 274
Depreciation and depletion	**8**	5	3	**-**	-	-	**728**	780	831
Financing costs (note 13)	**3**	31	20	**-**	-	-	**-**	36	28
Total expenses	**(27)**	305	200	**(8 755)**	(6 786)	(6 438)	**26 303**	21 064	20 688
Income before income taxes	**76**	(216)	(133)	**-**	-	-	**5 276**	4 379	4 100
Income taxes (note 4)									
Current	**(27)**	(52)	(60)	**-**	-	-	**1 005**	1 163	776
Deferred	**44**	35	26	**-**	-	-	**393**	28	280
Total income tax expense	**17**	(17)	(34)	**-**	-	-	**1 398**	1 191	1 056
Net income	**59**	(199)	(99)	**-**	-	-	**3 878**	3 188	3 044
Cash flow from (used in) operating activities	**101**	(45)	(105)	**-**	-	-	**4 263**	3 626	3 587
Capital and exploration expenditures	**8**	36	48	**-**	-	-	**1 363**	978	1 209
Property, plant and equipment									
Cost	**313**	304	269	**-**	-	-	**24 165**	22 962	22 478
Accumulated depreciation and depletion	**(119)**	(111)	(104)	**-**	-	-	**(12 917)**	(12 401)	(12 021)
Net property, plant and equipment (d)(e)	**194**	193	165	**-**	-	-	**11 248**	10 561	10 457
Total assets	**1 982**	1 251	2 145	**(174)**	(338)	(471)	**17 035**	16 287	16 141

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

millions of dollars	**2008**	2007	2006
Total external and intersegment sales	**4 766**	3 923	3 303
Total expenses	**3 002**	2 394	1 966
Net income, after income tax	**1 302**	1 224	1 148
Total current assets	**758**	1 043	516
Long-term assets	**5 380**	4 868	4 833
Total current liabilities	**659**	705	810
Other long-term obligations	**619**	460	344
Cash flow from operating activities	**1 891**	865	1 229
Cash (used in) investing activities	**(685)**	(131)	(403)

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

millions of dollars	**2008**	2007	2006
Upstream	**3 095**	2 013	1 936
Downstream	**1 685**	922	869
Chemical	**844**	768	793
Total export sales	**5 624**	3 703	3 598

(c) Consolidated selling and general expenses include delivery costs from final storage areas to customers of $314 million in 2008 (2007-$318 million, 2006 - $316 million,).

(d) Includes property, plant and equipment under construction of $1,523 million (2007-$951 million).

(e) 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	**2008**	2007	2006
Current income tax expense	**1 005**	1 163	776
Deferred income tax expense (a)	**393**	28	280
Total income tax expense (b)	**1 398**	1 191	1 056
Statutory corporate tax rate (percent)	**29.5**	30.1	32.8
Increase/(decrease) resulting from:			
Enacted tax rate change	**-**	(2.2)	(2.7)
Other	**(3.0)**	(0.7)	(4.3)
Effective income tax rate	**26.5**	27.2	25.8

(a) The provisions for deferred income taxes in 2008 include net (charges)/credits for the effect of changes in tax laws and rates of $1 million (2007 -$90 million, 2006 -$81 million).

(b) Cash outflow from income taxes, plus investment credits earned, was $1,101 million in 2008 (2007 $1,395 million, 2006 $1,000 million).

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

millions of dollars	**2008**	2007	2006
Post-retirement benefits liability adjustment:			

Net actuarial loss/(gain)	**102**	21	
Amortization of net actuarial (loss)/gain	**(26)**	(24)	
Prior service cost	**-**	13	
Amortization of prior service cost	**(5)**	(6)	
Total post-retirement benefits liability adjustment	**71**	4	212
Minimum pension liability adjustment	**-**	-	(146)

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

millions of dollars	**2008**	2007	2006
Depreciation and amortization	**1685**	1624	1588
Successful drilling and land acquisitions	**258**	276	263
Pension and benefits	**(312)**	(249)	(311)
Site restoration	**(202)**	(156)	(161)
Net tax loss carryforwards (a)	**(2)**	(37)	(42)
Capitalized interest	**53**	49	50
Other	**9**	(36)	(42)
Deferred income tax liabilities	**1 489**	1 471	1 345
LIFO inventory valuation	**(301)**	(547)	(448)
Other	**(60)**	(113)	(125)
Deferred income tax assets	**(361)**	(660)	(573)
Valuation allowance	**-**	-	-
Net deferred income tax liabilities	**1 128**	811	772

(a) Tax losses can be carried forward indefinitely.

Unrecognized tax benefits

As of January 1, 2007, the company adopted the Financial Accounting Standards Board (FASB) Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes . The cumulative adjustment for the accounting change reported in 2007 was an after-tax gain of $14 million. The gain reflected the recognition of several refund claims with associated interest, partly offset by increased income tax reserves.

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 individual 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	**2008**	2007
January 1 balance	**170**	142
Additions for prior years tax positions	**9**	28
Reductions for prior years tax positions	**(29)**	-
December 31 balance	**150**	170

The 2008 and 2007 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 2004 to 2007 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 2003. Management is currently evaluating those proposed adjustments. Management believes that a number of outstanding matters before 2004 are expected to be resolved in 2009. 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. Funding of registered retirement plans complies with federal and provincial pension regulations, and the company makes contributions to the plans based on an independent actuarial valuation.

Pension income benefits consist mainly of company-paid defined benefit plans that are based on years of service and final average earnings. The company shares in the cost of health care and life insurance benefits. The company s benefit obligations are based on the projected benefit method of valuation that includes employee service to date and present compensation levels as well as a projection of salaries 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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The benefit obligations and plan assets associated with the company s defined benefit plans are measured on December 31.

	Pension benefits		Other post-retirement benefits	
	2008	2007	**2008**	2007
Assumptions used to determine benefit obligations at December 31 (percent)				
Discount rate	**7.50**	5.75	**7.50**	5.75
Long-term rate of compensation increase	**4.50**	3.50	**4.50**	3.50
millions of dollars				
Change in projected benefit obligation				
Projected benefit obligation at January 1	**4 685**	4 716	**426**	441
Current service cost	**94**	100	**6**	6
Interest cost	**271**	246	**25**	23
Amendments	**-**	41	**-**	-
Actuarial loss/(gain)	**(583)**	(131)	**(61)**	(25)
Benefits paid (a)	**(331)**	(287)	**(24)**	(19)
Projected benefit obligation at December 31	**4 136**	4 685	**372**	426
Accumulated benefit obligation at December 31	**3 719**	4 208		
Change in plan assets				
Fair value at January 1	**4 098**	4 089		
Actual return/(loss) on plan assets	**(699)**	93		
Company contributions	**165**	163		
Benefits paid (b)	**(252)**	(247)		
Fair value at December 31	**3 312**	4 098		
Plan assets in excess of/(less than) projected benefit obligation at December 31				
Funded plans	**(488)**	(213)	**-**	-
Unfunded plans	**(336)**	(374)	**(372)**	(426)
Total (c)	**(824)**	(587)	**(372)**	(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.

Effective December 31, 2006, the company adopted Statement of Financial Accounting Standards No. 158 (SFAS 158), Employers Accounting for Defined Benefit Pension and Other Post-retirement Plans, an amendment to FASB Statements No. 87, 88, 106 and 132(R) , which requires an employer to recognize the overfunded or underfunded status of a defined benefit post-retirement plan as an asset or liability in its balance sheet and to recognize changes in that funded status in the year in which the changes occur through other comprehensive income.

	Pension benefits			Other post-retirement benefits		
millions of dollars	**2008**	2007	2006	**2008**	2007	2006
Amounts recorded in the consolidated balance sheet consist of:						
Current liabilities	**(22)**	(34)		**(23)**	(25)	
Other long-term obligations	**(802)**	(553)		**(349)**	(401)	
Total recorded	**(824)**	(587)		**(372)**	(426)	
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	**1 331**	977		**(25)**	42	
Prior service cost	**77**	95		**-**	-	
Total recorded in accumulated other comprehensive income, before tax	**1 408**	1 072		**(25)**	42	

Assumptions used to determine net periodic benefit cost for years ended December 31 (percent)						
Discount rate	**5.75**	5.25	5.00	**5.75**	5.25	5.00
Long-term rate of compensation increase	**3.50**	3.50	3.50	**3.50**	3.50	3.50
Long-term rate of return on funded assets	**8.00**	8.00	8.25	**-**	-	-

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millions of dollars	Pension benefits 2008	2007	2006	Other post-retirement benefits 2008	2007	2006
Components of net periodic benefit cost						
Current service cost	**94**	100	100	**6**	6	8
Interest cost	**271**	246	238	**25**	23	23
Expected return on plan assets	**(330)**	(329)	(299)	**-**	-	-
Amortization of prior service cost	**19**	20	20	**-**	-	-
Recognized actuarial loss/(gain)	**91**	76	114	**6**	6	8
Net periodic benefit cost	**145**	113	173	**37**	35	39
Changes in amounts recorded in accumulated other comprehensive income						
Net actuarial loss/(gain)	**446**	105	72	**(61)**	(25)	73
Amortization of net actuarial (loss)/gain included in net periodic benefit cost	**(91)**	(76)	-	**(5)**	(6)	-
Prior service cost	**-**	41	74	**-**	-	-
Amortization of prior service cost included in net periodic benefit cost	**(19)**	(20)	-	**-**	-	-
Total recorded in accumulated other comprehensive income	**336**	50	146	**(66)**	(31)	73
Total recorded in net periodic benefit cost and accumulated other comprehensive income, before tax	**481**	163	319	**(29)**	4	112

Costs for defined contribution plans, primarily the employee savings plan, were $33 million in 2008 (2007 -$31 million, 2006 - $30 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 2008	2007	2006
(Charge)/credit to accumulated other comprehensive income, before tax	**(270)**	(19)	(219)
Deferred income tax (charge)/credit (note 4)	**71**	4	66
(Charge)/credit to accumulated other comprehensive income, after tax	**(199)**	(15)	(153)

The preceding data in this note conforms with current accounting standards that specify use of a discount rate at which post-retirement liabilities could be effectively settled. The discount rate for calculating year-end post-retirement liabilities is based on the yield for high quality, long-term Canadian corporate bonds at year-end with an average maturity (or duration) approximately that of the liabilities. The measurement of the accumulated post-retirement benefit obligation assumes a health care cost trend rate of 6.50 percent in 2009 that declines to 4.50 percent by 2011.

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 2008 long-term expected return of 8.00 percent used in the calculations of pension expense compares to an actual rate of return of 5.00 percent and 8.31 percent over the last 10- and 20- year periods ending December 31, 2008.

The company s pension plan asset allocation at December 31, 2007 and 2008, and target allocation for 2009 are as follows:

Asset category (percent)	Target allocation 2009	Percentage of plan assets at December 31 2008	2007
Equity securities	50-75	**63**	61
Debt securities	25-50	**36**	38
Other	0-10	**1**	1

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

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

	Pension benefits	
millions of dollars	**2008**	**2007**
For funded pension plans with accumulated benefit obligations in excess of plan assets:		
Projected benefit obligation	**3 800**	398
Accumulated benefit obligation	**3 420**	318
Fair value of plan assets	**3 312**	254
Accumulated benefit obligation less fair value of plan assets	**108**	64
For unfunded plans covered by book reserves:		
Projected benefit obligation	**336**	373
Accumulated benefit obligation	**299**	347

Estimated 2009 amortization from accumulated other comprehensive income

millions of dollars	Pension benefits	Other post-retirement benefits
Net actuarial loss/(gain) (a)	110	(1)
Prior service cost (b)	17	-

(a) The company amortizes the net balance of actuarial loss/(gain) over the average remaining service period of active plan participants.
(b) The company amortizes prior service cost on a straight-line basis as permitted under SFAS 87 and SFAS 106.

Cash flows

Benefit payments expected in:

millions of dollars	Pension benefits	Other post-retirement benefits
2009	274	25
2010	277	25
2011	282	25
2012	288	25
2013	296	25
2014 - 2018	1 623	128

In 2009, the company expects to make cash contributions of about $200 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	One percent increase	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	(440)	530
Rate of pay increases:		
Effect on net benefit cost, before tax	35	(30)
Effect on benefit obligation	115	(105)

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

Increase/(decrease)

millions of dollars	One percent increase	One percent decrease
Effect on service and interest cost components	4	(3)
Effect on benefit obligation	31	(26)

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6. Other long-term obligations

millions of dollars	2008	2007
Employee retirement benefits (note 5) (a)	**1 151**	954
Asset retirement obligations and other environmental liabilities (b)	**728**	522
Share-based incentive compensation liabilities (note 8)	**203**	210
Other obligations	**216**	228
Total other long-term obligations	**2 298**	1 914

(a) Total recorded employee retirement benefit obligations also include $45 million in current liabilities (2007 $59 million).
(b) Total asset retirement obligations and other environmental liabilities also include $83 million in current liabilities (2007 $74 million).

The following table summarizes the activity in the liability for asset retirement obligations:

millions of dollars	2008	2007
January 1 balance	**488**	422
Additions	**232**	71
Accretion	**29**	25
Settlement	**(38)**	(30)
December 31 balance	**711**	488

7. Derivatives and financial instruments

The company did not enter into any energy derivatives, foreign-exchange forward contracts or currency and interest-rate swaps in the past three years. The company maintains a system of controls that includes a policy covering the authorization, reporting and monitoring of derivative activity.

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

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.

Incentive share units, deferred share units and restricted stock units

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

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

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

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

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 fifty 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 these units by using the fair-value-based method. The fair value of awards in the form of incentive share, deferred share and restricted stock units is the market price of the company s stock. Under this method, compensation expense related to the units of

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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, 2008:

	Incentive share units	Deferred share units	Restricted stock units
Outstanding at January 1, 2008	**6 758 850**	**90 526**	**10 219 851**
Granted	**-**	**10 937**	**1 760 795**
Exercised	**(1 249 335)**	**(15 092)**	**(1 328 233)**
Cancelled or adjusted	**1 500**	**-**	**(55 850)**
Outstanding at December 31, 2008	**5 511 015**	**86 371**	**10 596 563**

There was a $33 million favourable adjustment to previously recorded compensation expenses for these programs in the year ended December 31, 2008. The compensation expense charged against income for these programs was $202 million and $133 million for the years ended December 31, 2007 and 2006, respectively. Income tax expense associated with the favourable adjustment to compensation expense for the year ended December 31, 2008 was $5 million, and the income tax benefit recognized in income related to compensation expense for these programs was $67 million and $45 million for the years ended December 31, 2007 and 2006, respectively. Cash payments of $115 million, $159 million and $162 million for these programs were made in 2008, 2007 and 2006, respectively.

As of December 31, 2008, there was $201 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, 2008.

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, 2008. Any unexercised options expire after April 29, 2012. The company has not issued incentive stock options since 2002 and has no plans to issue incentive stock options in the future.

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

No compensation expense and no income tax benefit related to stock options were recognized for stock options in the years ended December 31, 2008, 2007 and 2006. The aggregate intrinsic value of stock options exercised was $17 million, $25 million and $18 million in the years ended December 31, 2008, 2007 and 2006, respectively, and for the balance of outstanding stock options is $109 million as at December 31, 2008.

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, 2008:

		2008	
	Units	Exercise price (dollars)	Remaining contractual term (years)
Incentive stock options			
Outstanding at January 1	**4 728 780**	**15.50**	

Granted	**-**		
Exercised	**(434 145)**	**15.50**	
Cancelled or adjusted	**-**		
Outstanding at December 31	**4 294 635**	**15.50**	**3.3**

9. Investment and other income

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

millions of dollars	**2008**	2007	2006
Proceeds from asset sales	**272**	279	212
Book value of assets sold	**31**	64	78
Gain/(loss) on asset sales, before tax (a)(b)	**241**	215	134
Gain/(loss) on asset sales, after tax (a)(b)	**209**	156	96

(a) 2007 included a gain of $200 million ($142 million, after tax) from the sale of the company s interests in a natural gas producing property in British Columbia and in the Willesden Green producing property.

(b) 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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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 or financial condition.

The Alberta government enacted changes to the oil and gas and generic oil sands royalty regime effective 2009. The impacts of the changes have been incorporated in the company s 2008 oil and gas reserves and mined bitumen reserves calculation, where appropriate. 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, beginning January 1, 2010, Syncrude will begin transitioning to the new oil sands royalty regime by paying additional royalties, the exact amount of which will depend on production levels from 2010 to 2015. Also, beginning January 1, 2009, Syncrude s royalty will be based on bitumen value with upgrading costs and revenues excluded from the calculation. The impacts of the amended agreement have been incorporated in the 2008 synthetic crude oil reserves calculation.

The company was contingently liable at December 31, 2008 for a maximum of $79 million relating to guarantees for purchasing operating equipment and other assets from its rural marketing associates upon expiry of the associate agreement or the resignation of the associate. The company expects that the fair value of the operating equipment and other assets so purchased would cover the maximum potential amount of future payment under the guarantees.

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						
						After	
millions of dollars	2009	2010	2011	2012	2013	2013	Total
Unconditional purchase obligations (a)	**127**	**63**	**74**	**43**	**82**	**31**	**420**

(a) Undiscounted obligations of $420 million mainly pertain to pipeline throughput agreements. Total payments under unconditional purchase obligations were $117 million (2007 - $94 million, 2006 - $100 million). The present value of these commitments, excluding imputed interest of $66 million, totaled $354 million.

11. Common shares

	As at	As at
thousands of shares	**Dec. 31 2008**	Dec. 31 2007
Authorized	**1 100 000**	1 100 000

From 1995 to 2007, the company purchased shares under twelve 12-month normal course share purchase programs, as well as an auction tender. On June 25, 2008, a 12-month share repurchase program was implemented with an allowable purchase of about 44 million shares (five percent of the total at June 16, 2008), 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 shown below.

Year	Purchased	Millions of

	shares	dollars
	(thousands)	
1995 to 2006	795 623	10 453
2007	50 516	2 358
2008	**44 295**	**2 210**
Cumulative purchases to date	890 434	15 021

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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The company s common share activities are summarized below:

	Thousands of shares	Millions of dollars
Balance as at January 1, 2006	997 875	1 747
Issued for cash under the stock option plan	627	10
Purchases at stated value	(45 514)	(80)
Balance as at December 31, 2006	952 988	1 677
Issued for cash under the stock option plan	791	12
Purchases at stated value	(50 516)	(89)
Balance as at December 31, 2007	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**

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

	2008	2007	2006
Net income per common share - basic			
Net income (millions of dollars)	**3 878**	3 188	3 044
Weighted average number of common shares outstanding (thousands of shares)	**882 604**	928 527	975 128
Net income per common share (dollars)	**4.39**	3.43	3.12
Net income per common share - diluted			
Net income (millions of dollars)	**3 878**	3 188	3 044
Weighted average number of common shares outstanding (thousands of shares)	**882 604**	928 527	975 128
Effect of employee share-based awards (thousands of shares)	**6 418**	5 811	4 460
Weighted average number of common shares outstanding, assuming dilution (thousands of shares)	**889 022**	934 338	979 588
Net income per common share (dollars)	**4.36**	3.41	3.11

12. Miscellaneous financial information

In 2008, net income included an after-tax gain of $27 million (2007 - $25 million gain, 2006 - $14 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, 2008 by $994 million (2007 - $1,953 million). Inventories of crude oil and products at year-end consisted of the following:

millions of dollars	**2008**	2007
Crude oil	**328**	211
Petroleum products	**268**	298
Chemical products	**65**	43
Natural gas and other	**12**	14
Total inventories of crude oil and products	**673**	566

Research and development costs in 2008 were $83 million (2007 $89 million, 2006 $73 million) before investment tax credits earned on these expenditures of $9 million (2007 $9 million, 2006 $7 million). Research and development costs are included in expenses due to the uncertainty of future benefits.

Cash flow from operating activities included dividends of $11 million received from equity investments in 2008 (2007 $22 million, 2006 $18 million).

13. Financing costs

millions of dollars	**2008**	2007	2006
Debt-related interest	**8**	62	63
Capitalized interest	**(8)**	(36)	(48)
Net interest expense	**-**	26	15
Other interest	**-**	10	13
Total financing costs (a)	**-**	36	28

(a) Cash interest payments in 2008 were $6 million (2007 - $80 million, 2006 - $71 million). The weighted average interest rate on short-term borrowings in 2008 was 3.5 percent (2007 - 5.1 percent).

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14. Leased facilities and capitalized lease obligations
At December 31, 2008, the company held non-cancelable operating leases covering office buildings, rail cars, service stations and other properties with minimum undiscounted lease commitments totaling $432 million as indicated in the following table:

	Payments due by period						
						After	
millions of dollars	2009	2010	2011	2012	2013	2013	Total
Lease payments under minimum commitments (a)	**64**	**53**	**55**	**53**	**49**	**158**	**432**

(a) Total rental expense incurred for operating leases in 2008 was $149 million (2007 - $98 million, 2006 - $101 million) which included minimum rental expenditures of $140 million (2007 - $86 million, 2006 - $88 million). Related rental income was not material.

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 11.0 percent in 2008 (2007 - 10.9 percent). Total capitalized lease obligations also include $4 million in current liabilities (2007 - $4 million).

Principal payments on capital leases of approximately $4 million a year are due in each of the next five years.

15. Transactions with related parties
Revenues and expenses of the company also include the results of transactions with Exxon Mobil Corporation and affiliated companies (ExxonMobil) in the normal course of operations. These were conducted on terms as favourable as they would have been with unrelated parties and primarily consisted of the purchase and sale of crude oil, natural gas, petroleum and chemical products, as well as transportation, technical and engineering services. Transactions with ExxonMobil also included amounts paid and received in connection with the company s participation in a number of upstream activities conducted jointly in Canada.

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. This contractual agreement is designed to provide organizational efficiencies and to reduce costs. No separate legal entities were created from this arrangement. Separate books of account continue to be maintained for 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;
(d) share new upstream opportunities on an up to equal basis.

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

As at December 31, 2008, the company had outstanding loans of $35 million (2007 - $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.