IMPERIAL OIL LTD
Form 10-K
February 23, 2017
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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, 2016	**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.)**

505 QUARRY PARK BOULEVARD S.E., CALGARY, AB, CANADA	**T2C 5N1**
(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 Act).

Yes 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

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 No......

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

Yes 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 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 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

As of the last business day of the 2016 second fiscal quarter, the aggregate market value of the voting stock held by non-affiliates of the registrant was Canadian $10,533,578,543 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 8, 2017, was 847,599,011.

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

Note that numbers may not add due to rounding.

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

dollars	**2016**	2015	2014	2013	2012
Rate at end of period	**0.7448**	0.7226	0.8620	0.9401	1.0042
Average rate during period	**0.7559**	0.7748	0.9023	0.9665	1.0006
High	**0.7972**	0.8529	0.9423	1.0164	1.0299
Low	**0.6853**	0.7148	0.8588	0.9348	0.9600

On February 8, 2017, 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 $0.7601 U.S. = $1.00 Canadian.

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Forward-looking statements

Statements of future events or conditions in this report, including projections, targets, expectations, estimates, and business plans are forward-looking statements. Actual future financial and operating results, including demand growth and energy source mix; production growth and mix; project plans, dates, costs and capacities; production rates; production life and resource recoveries; cost savings; product sales; financing sources; and capital and environmental expenditures could differ materially depending on a number of factors, such as changes in the supply of and demand for crude oil, natural gas, and petroleum and petrochemical products and resulting price and margin impacts; limitations on transportation for accessing markets; political or regulatory events, including changes in law or government policy, applicable royalty rates and tax laws; the receipt, in a timely manner, of regulatory and third-party approvals; third party opposition to operations and projects; environmental risks inherent in oil and gas exploration and production activities; environmental regulation, including climate change and greenhouse gas restrictions; currency exchange rates; availability and allocation of capital; performance of third party service providers; unanticipated operational disruptions; management effectiveness; commercial negotiations; project management and schedules; response to unexpected technological developments; operational hazards and risks; disaster response preparedness; the ability to develop or acquire additional reserves; and other factors discussed in Item 1A of this annual report on Form 10-K and in the management s discussion and analysis of financial condition and results of operations contained in Item 7. Forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Imperial Oil Limited. Imperial Oil Limited s actual results may differ materially from those expressed or implied by its forward-looking statements and readers are cautioned not to place undue reliance on them. Imperial Oil Limited undertakes no obligation to update any forward-looking statements contained herein, except as required by applicable law.

The term project as used in this report can refer to a variety of different activities and does not necessarily have the same meaning as in any government payment transparency reports.

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 505 Quarry Park Boulevard S.E. Calgary, Alberta, Canada T2C 5N1. Exxon Mobil Corporation (ExxonMobil) owns approximately 69.6 percent of the outstanding shares of the company. In this report, unless the context otherwise indicates, reference to the company or Imperial includes Imperial Oil Limited and its subsidiaries.

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

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

Financial information about segments and geographic areas for the company is contained in the Financial section of this report under note 2 to the consolidated financial statements: Business segments .

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Upstream

Disclosure of reserves

Summary of oil and gas reserves at year-end

The table below summarizes the net proved reserves for the company, as at December 31, 2016, as detailed in the Supplemental information on oil and gas exploration and production activities part of the Financial section, starting on page 30 of this report.

All of the company s reported reserves are located in Canada. The company has reported proved reserves based on the average of the first-day-of-the-month price for each month during the last 12-month period ending December 31. Natural gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels. No major discovery or other favourable or adverse event has occurred since December 31, 2016 that would cause a significant change in the estimated proved reserves as of that date.

	Liquids (a)	Natural gas	Synthetic oil	Bitumen	Total oil-equivalent basis
	millions of barrels	billions of cubic feet	millions of barrels	millions of barrels	millions of barrels
Net proved reserves:					
Developed	**19**	**263**	**564**	**436**	**1,063**
Undeveloped	**16**	**232**	**-**	**265**	**319**
Total net proved	**35**	**495**	**564**	**701**	**1,382**

(a) Liquids include crude oil, condensate and natural gas liquids (NGLs). NGL proved reserves are not material and are therefore included under liquids.

The estimation of proved reserves, which is based on the requirement of reasonable certainty, is an ongoing process based on rigorous technical evaluations, commercial and market assessments and detailed analysis of well information such as flow rates and reservoir pressures. Furthermore, the company only records proved reserves for projects which have received significant funding commitments by management made toward the development of the reserves. Although the company is reasonably certain that proved reserves will be produced, the timing and amount recovered can be affected by a number of factors, including completion of development projects, reservoir performance, regulatory approvals, royalty framework and significant changes in projections of long-term oil and gas price levels. In addition, proved reserves could be affected by an extended period of low prices which could reduce the level of the company s capital spending and also impact its partners capacity to fund their share of joint projects.

As a result of low prices during 2016, under the U.S. Securities and Exchange Commission definition of proved reserves, certain quantities of bitumen that qualified as proved reserves in prior years did not qualify as proved reserves at year-end 2016. Amounts no longer qualifying as proved reserves include the entire 2.5 billion barrels of bitumen at Kearl and approximately 0.2 billion barrels of bitumen at Cold Lake. Among the factors that would result in these amounts being recognized again as proved reserves at some point in the future are a recovery in average price levels, a further decline in costs, and / or operating efficiencies. Under the terms of certain contractual arrangements or government royalty regimes, lower prices can also increase proved reserves attributable to Imperial. The company does not expect the downward revision of reported proved reserves under the U.S. Securities and Exchange Commission definitions to affect the operation of the underlying projects or to alter its outlook for future production volumes.

Technologies used in establishing proved reserves estimates

Imperial s proved reserves in 2016 were based on estimates generated through the integration of available and appropriate geological, engineering and production data, utilizing well established technologies that have been demonstrated in the field to yield repeatable and consistent results.

Data used in these integrated assessments included information obtained directly from the subsurface via wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data utilized also included subsurface information obtained through indirect measurements, including high-quality 3-D and 4-D seismic data, calibrated with available well control information. The tools used to interpret the data included proprietary seismic processing software, proprietary reservoir modeling and simulation software and commercially available data analysis packages.

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

Preparation of reserves estimates

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

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

The internal qualified reserves evaluator is a professional engineer registered in Alberta, Canada and has over 30 years of petroleum industry experience, including 23 years of reserves related experience. The position provides leadership to the internal reserves management group and is responsible for filing a reserves report with the Canadian securities regulatory authorities. The company s internal reserves evaluation staff consists of 39 persons with an average of 15 years of relevant technical experience in evaluating reserves, of whom 24 persons are qualified reserves evaluators for purposes of Canadian securities regulatory requirements. The company s internal reserves evaluation management team is made up of 19 persons with an average of 14 years of relevant experience in evaluating and managing the evaluation of reserves. No independent qualified reserves evaluator or auditor was involved in the preparation of the company s reserves data.

Proved undeveloped reserves

As at December 31, 2016, approximately 23 percent of the company s proved reserves were proved undeveloped reserves reflecting volumes of 319 million oil-equivalent barrels. Most of the undeveloped reserves are associated with the Cold Lake field. This compared to 513 million oil-equivalent barrels of proved undeveloped reserves reported at the end of 2015. Proved undeveloped reserves decreased by 177 million oil-equivalent barrels in 2016 associated with end of field life truncation as a result of low oil and natural gas prices. Migration of proved undeveloped reserves into proved developed was not material in 2016.

Proved undeveloped reserves that have remained undeveloped for five years or more represent about 22 percent (71 million oil-equivalent barrels) of proved undeveloped reserves and are primarily associated with Cold Lake s ongoing drilling program. These undeveloped reserves are planned to be developed in a staged approach to align with operational capacity and efficient capital spending commitment over the life of the field. The company is reasonably certain that these proved reserves will be produced; however the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, and significant changes in long-term oil prices.

One of the company s requirements to report resources as proved reserves is that management has made significant funding commitments towards the development of the reserves. The company has a disciplined investment strategy and many major fields require a long lead-time in order to be developed. The company made investments of about $105 million during the year to progress the development of reported proved undeveloped reserves in the Montney and Duvernay formations, and at Cold Lake. These investments represented about 12 percent of the $896 million in total reported Upstream capital and exploration expenditures. Investments made by the company to develop quantities which no longer meet the SEC definition of proved reserves due to 2016 average prices are included in the $896 million of Upstream capital and exploration expenditures.

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Oil and gas production, production prices and production costs

Reference is made to the portion of the Financial section entitled Management s discussion and analysis of financial condition and results of operations on page 34 of this report for a narrative discussion on the material changes.

Average daily production of oil

The company s average daily oil production by final products sold during the three years ended December 31, 2016 was as follows. All reported production volumes were from Canada.

thousands of barrels per day (a)		**2016**	2015	2014
Bitumen:				
Cold Lake:	- gross (b)	**161**	158	146
	- net (c)	**138**	139	114
Kearl:	- gross (b)	**120**	108	51
	- net (c)	**118**	106	47
Total bitumen:	- gross (b)	**281**	266	197
	- net (c)	**256**	245	161
Synthetic oil (d):	- gross (b)	**68**	62	64
	- net (c)	**67**	58	60
Liquids:	- gross (b)	**15**	16	21
	- net (c)	**13**	15	16
Total:	- gross (b)	**364**	344	282
	- net (c)	**336**	318	237

(a) Barrels per day metric is calculated by dividing the volume for the period by the number of calendar days in the period.

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

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

(d) The company s synthetic oil production volumes were from the company s share of production volumes in the Syncrude joint venture.

Average daily production and production available for sale of natural gas

The company s average daily production and production available for sale of natural gas during the three years ended December 31, 2016 are set forth below. All reported production volumes were from Canada. All gas volumes in this report are calculated at a pressure base of 14.73 pounds per square inch absolute at 60 degrees Fahrenheit. Reference is made to the portion of the Financial section entitled Management s discussion and analysis of financial condition and results of operations on page 34 of this report for a narrative discussion on the material changes.

millions of cubic feet per day (a)	**2016**	2015	2014
Gross production (b) (c)	**129**	130	168
Net production (c) (d) (e)	**122**	125	156
Net production available for sale (f)	**87**	94	124

(a) Cubic feet per day metric is calculated by dividing the volume for the period by the number of calendar days in the period.

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

(c) Production of natural gas includes amounts used for internal consumption with the exception of the amounts reinjected.

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

(e) Net production reported in the above table is consistent with production quantities in the net proved reserves disclosure.

(f) Includes sales of the company s share of net production and excludes amounts used for internal consumption.

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Total average daily oil-equivalent basis production

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

thousands of barrels per day (a)	**2016**	2015	2014
Total production oil-equivalent basis:			
- gross (b)	**386**	366	310
- net (c)	**356**	339	263

(a) Barrels per day metric is calculated by dividing the volume for the period by the number of calendar days in the period.
(b) Gross production is the company s share of production (excluding purchases) before deduction of the mineral owners or governments share or both.
(c) Net production is gross production less the mineral owners or governments share or both.

Average unit sales price

The company s average unit sales price and average unit production costs by product type for the three years ended December 31, 2016 were as follows.

Canadian dollars per barrel	**2016**	2015	2014
Bitumen	**26.52**	32.48	67.20
Synthetic oil	**57.12**	61.33	99.58
Liquids	**28.01**	30.62	67.82
dollars per thousand cubic feet			
Natural gas	**2.41**	2.78	4.54

In 2016, Imperial s average Canadian dollar realizations for bitumen and synthetic crudes declined essentially in line with the North American benchmarks, adjusted for changes in the exchange rate and transportation costs.

Unit sales prices decreased in 2015, primarily driven by the decline in the global crude oil and natural gas price environment.

Average unit production costs

Canadian dollars per barrel	**2016**	2015	2014
Bitumen	**24.24**	25.16	34.87
Synthetic oil	**46.24**	54.81	62.14

Total oil-equivalent basis (a)	**28.52**	30.60	41.02

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

In 2016, synthetic oil unit production costs were lower, primarily driven by increased volumes and cost management.

Bitumen unit production costs were lower in 2015, primarily driven by Kearl expansion project start-up and cost management.

Synthetic oil unit production costs were lower in 2015, primarily driven by cost management.

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Drilling and other exploratory and development activities

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

Wells drilled

The following table sets forth the net exploratory and development wells that were drilled or participated in by the company during the three years ended December 31, 2016.

wells	**2016**	2015	2014
Net productive exploratory	**-**	-	-
Net dry exploratory	**-**	-	-
Net productive development	**6**	46	111
Net dry development	**-**	-	-
Total	**6**	46	111

In 2015, the following wells were drilled to add productive capacity: 41 development wells at Cold Lake, of which 36 development wells relate to the Cold Lake Nabiye expansion project and five net other wells.

In 2014, the following wells were drilled to add productive capacity: 90 development wells at Cold Lake, of which 74 development wells relate to the Cold Lake Nabiye expansion project, eight net tight gas wells and 13 net other wells.

Wells drilling

At December 31, 2016, the company was participating in the drilling of the following exploratory and development wells. All wells were located in Canada.

	2016	
wells	Gross	Net
Total	**13**	**6**

Exploratory and development activities regarding oil and gas resources

Cold Lake

To maintain production at Cold Lake, capital expenditures for additional production wells and associated facilities are required periodically. Additional wells were drilled on existing phases in 2015. No wells were drilled in 2016.

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

Aspen, Cold Lake expansion and other oil sands activities

The company filed a regulatory application for a new in-situ oil sands project at Aspen in December 2013, using steam-assisted gravity drainage (SAGD) technology to develop the project in three phases producing about 45,000 barrels per day before royalties, per phase.

In 2015, the company amended the regulatory application to develop the Aspen project using solvent-assisted, steam-assisted gravity drainage (SA-SAGD) technology. The technology significantly improves capital efficiency and lowers greenhouse gas intensity versus the existing SAGD technologies. The project is proposed to be executed in two phases producing about 75,000 barrels per day before royalties, per phase. Development timing is subject to regulatory approvals and market conditions. No final investment decision has been made.

In March 2016, Imperial filed a regulatory application for the Cold Lake Expansion project to develop the Grand Rapids interval using SA-SAGD technology. The project is proposed to produce 50,000 barrels per day, before royalties. Development timing is subject to regulatory approval and market conditions. No final investment decision has been made.

Work continues on technical evaluations to support potential Corner and Clyden in-situ development regulatory applications.

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

Other activities

The company is continuing to evaluate other undeveloped natural gas resources in the Montney and Duvernay formations in the western provinces.

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.

In late 2010, the National Energy Board (NEB) announced its approval of plans to build and operate the project subject to 264 conditions in areas such as engineering, safety and environmental protection. Federal cabinet approved the project in early 2011.

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, continued support from northern parties, fiscal framework and the cost of constructing, operating and abandoning the field production and pipeline facilities.

In 2016, the Federal Government of Canada approved the extension of the pipeline and gathering system construction permits to December 31, 2022. No final investment decision has been made.

Beaufort Sea

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

In 2010, the company executed an agreement to cross-convey interests with another company to acquire a 25 percent interest in an additional Beaufort Sea exploration licence. As a result of that agreement, the company operates both licences and its interest in the original licence was reduced to 25 percent. The exploration licences are held through 2019 and 2020, respectively.

In 2013, the company and its joint venture partners filed a project description, initiating the formal regulatory review of the project.

In December 2016, the Federal Government of Canada declared Arctic waters off limits to new offshore oil and gas licences for five years subject to review at the end of that period. Existing licences will not be impacted. The government has indicated they will undertake a one year consultation process to discuss the interests of existing leaseholders, including Imperial. Current activities continue to focus on data gathering and community consultation. Imperial is seeking extended terms for the Beaufort Sea exploration licences with the Federal Government of Canada. No final investment decision has been made.

Liquefied natural gas (LNG) activity

WCC LNG Ltd., jointly owned by the company (20 percent) and ExxonMobil Canada Ltd. (80 percent), was granted an export licence in 2013 for up to 30 million tonnes of LNG per year for a period of 25 years. In 2016, the licence period was extended to 40 years. The project is proceeding through the pre-application phase in a British Columbia environmental assessment process. No final investment decision has been made.

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

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

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Present activities

Review of principal ongoing activities

Cold Lake

Cold Lake is an in-situ heavy oil bitumen operation. The product, a blend of bitumen and diluent, is shipped to certain of the company s refineries, Exxon Mobil Corporation refineries and to other third parties. Diluent is natural gas condensate or other light hydrocarbons added to the crude bitumen to facilitate transportation by pipeline and rail.

The Province of Alberta, in its capacity as lessor of Cold Lake oil sands leases, is entitled to a royalty on production at Cold Lake. Royalties are subject to the oil sands royalty regulations which are based upon a sliding scale determined largely by the price of crude oil.

During 2016, net production at Cold Lake was about 138,000 barrels per day and gross production was about 161,000 barrels per day.

As a result of low prices during 2016, under the SEC definition of proved reserves, approximately 0.2 billion barrels of bitumen at Cold Lake no longer qualified as proved reserves at year-end 2016. The company does not expect the downward revision of reported proved reserves under SEC definitions to affect the Cold Lake operation or to alter Imperial s outlook for future production volumes. Among the factors that would result in these amounts being recognized again as proved reserves at some point in the future are a recovery in average price levels, a further decline in costs, and / or operating efficiencies.

Kearl

Kearl is a joint venture established to recover shallow deposits of oil sands using open-pit mining methods to extract the crude bitumen, which is processed through extraction and froth treatment trains. The company holds a 70.96 percent participating interest in the joint venture and ExxonMobil Canada Properties holds the other 29.04 percent. The product, a blend of bitumen and diluent, is shipped to certain of the company s refineries, Exxon Mobil Corporation refineries and to other third parties.

The Province of Alberta, in its capacity as lessor of Kearl oil sands leases, is entitled to a royalty on production at Kearl. Royalties are subject to the oil sands royalty regulations which are based upon a sliding scale determined largely by the price of crude oil.

During 2016, the company s share of Kearl s net bitumen production was about 118,000 barrels per day and gross production was about 120,000 barrels per day. Increased production in the year was due to the start-up of the expansion project.

Potential future debottlenecking of the Kearl operation would increase output to reach the regulatory capacity of 345,000 barrels of bitumen per day, of which the company s share would be about 245,000 barrels per day. Such debottlenecking remains under evaluation.

As a result of low prices during 2016, under the SEC definition of proved reserves, the entire 2.5 billion barrels of bitumen at Kearl no longer qualified as proved reserves at year-end 2016. The company does not expect the downward revision of reported proved reserves under SEC definitions to affect the Kearl operation or to alter Imperial s outlook for future production volumes. Among the factors that would result in these amounts being recognized again as proved reserves at some point in the future are a recovery in average price levels, a further decline in costs, and / or operating efficiencies.

Syncrude

Syncrude is a joint venture established to recover shallow deposits of oil sands using open-pit mining methods to extract crude bitumen, and then upgrade it to produce a high-quality, light (32 degrees API), sweet, synthetic crude oil. The company holds a 25 percent participating interest in the joint venture. The produced synthetic crude oil is shipped to certain of the company s refineries, Exxon Mobil Corporation refineries and to other third parties.

The Province of Alberta, in its capacity as lessor of Syncrude oil sands leases, is entitled to a royalty on production at Syncrude. In 2016, Syncrude transitioned to the new generic oil sands royalty regulations which are based on a sliding scale determined largely by the price of crude oil. Syncrude s royalties are based on bitumen value with upgrading costs and revenues excluded from the calculation.

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In 2016, the company s share of Syncrude s net production of synthetic crude oil was about 67,000 barrels per day and gross production was about 68,000 barrels per day.

Delivery commitments

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

Oil and gas properties, wells, operations and acreage

Production wells

The company s production of liquids, bitumen and natural gas is derived from wells located exclusively in Canada. The total number of wells capable of production, in which the company had interests at December 31, 2016 and December 31, 2015, is set forth in the following table. The statistics in the table are determined in part from information received from other operators.

	Year ended December 31, 2016				Year ended December 31, 2015			
	Crude oil		Natural gas		Crude oil		Natural gas	
wells	Gross (a)	Net (b)	Gross (a)	Net (b)	Gross (a)	Net (b)	Gross (a)	Net (b)
Total (c)	**4,752**	**4,647**	**3,546**	**1,188**	4,731	4,592	3,611	1,199

(a) Gross wells are wells in which the company owns a working interest.
(b) Net wells are the sum of the fractional working interests owned by the company in gross wells, rounded to the nearest whole number.
(c) Multiple completion wells are permanently equipped to produce separately from two or more distinctly different geological formations. At year-end 2016, the company had an interest in 16 gross wells with multiple completions (2015 - 26 gross wells).

Land holdings

At December 31, 2016 and 2015, the company held the following oil and gas rights, and bitumen and synthetic oil leases, all of which are located in Canada, specifically in the western provinces, in the Canada lands and in the Atlantic offshore.

		Developed		Undeveloped		Total	
thousands of acres		**2016**	2015	**2016**	2015	**2016**	2015
Western provinces (a):							
Liquids and gas	- gross (b)	**1,464**	1,400	**876**	1,016	**2,340**	2,416
	- net (c)	**703**	686	**482**	528	**1,185**	1,214
Bitumen	- gross (b)	**197**	193	**674**	673	**871**	866
	- net (c)	**182**	181	**319**	319	**501**	500
Synthetic oil	- gross (b)	**118**	118	**136**	136	**254**	254

	- net (c)	**29**	29	**34**	34	**63**	63
Canada lands (d):							
Liquids and gas	- gross (b)	**4**	4	**1,831**	2,274	**1,835**	2,278
	- net (c)	**2**	2	**498**	720	**500**	722
Atlantic offshore:							
Liquids and gas	- gross (b)	**65**	65	**288**	288	**353**	353
	- net (c)	**6**	6	**46**	46	**52**	52
Total (e):	- gross (b)	**1,848**	1,780	**3,805**	4,387	**5,653**	6,167
	- net (c)	**922**	904	**1,379**	1,647	**2,301**	2,551

(a) Western provinces include British Columbia, Alberta and Saskatchewan.

(b) Gross acres include the interests of others.

(c) Net acres exclude the interests of others.

(d) Canada lands include the Arctic Islands, Beaufort Sea / Mackenzie Delta, and other Northwest Territories, Nunavut and Yukon regions.

(e) Certain land holdings are subject to modification under agreements whereby others may earn interests in the company s holdings by performing certain exploratory work (farm-out) and whereby the company may earn interests in others holdings by performing certain exploratory work (farm-in).

Western provinces

The company s bitumen leases include about 194,000 net acres of oil sands leases near Cold Lake and an area of about 34,000 net acres at Kearl. The company also has about 80,000 net acres of undeveloped, mineable oil sands acreage in the Athabasca region. In addition, the company has interests in other bitumen oil sands leases in the Athabasca areas totalling about 193,000 net acres, which include about 62,000 net acres of oil sands leases in the Clyden area, about 34,000 net acres of oil sands in the Aspen area and about 30,000 net acres of oil sands in the Corner area. These 193,000 net acres are amenable to in-situ recovery techniques.

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

Oil sands leases have an exploration period of fifteen years and are continued beyond that point by meeting the minimum level of evaluation, by payment of escalating rentals, or by production. The majority of the acreage in Cold Lake, Kearl and Syncrude is continued by production.

The company holds interests in an additional 1,185,000 net acres of developed and undeveloped land in the western provinces related to crude oil and natural gas.

Petroleum and natural gas leases and licences from the western provinces have exploration periods ranging from two to 15 years and are continued beyond that point by proven production capability.

Canada lands

Land holdings in Canada lands primarily include exploration licence (EL) acreage in the Beaufort Sea of about 252,000 net acres and significant discovery licence (SDL) acreage in the Mackenzie Delta and Beaufort Sea areas of about 183,000 net acres. In 2016, the company surrendered its interest in the Summit Creek area of central Mackenzie Valley totalling about 222,000 net acres.

Exploration licences on Canada lands and Atlantic offshore have a finite term. If a significant discovery is made, a SDL may be granted that holds the acreage under the SDL indefinitely, subject to certain conditions.

The company s net acreage in Canada lands is either continued by production or held through ELs and SDLs.

Atlantic offshore

The Atlantic offshore acreage is continued by production or held by SDLs.

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Downstream

Supply

The company supplements its own production of crude oil, condensate and petroleum products with substantial purchases from a number of other sources at negotiated market prices. Purchases are made under both spot and term contracts from domestic and foreign sources, including ExxonMobil.

Transportation

Imperial currently transports the company s crude oil production and third party crude oil required to supply refineries by contracted pipelines, common carrier pipelines and rail. To mitigate uncertainty associated with the timing of industry pipeline projects and pipeline capacity constraints, the company has developed rail infrastructure. The Edmonton rail terminal commenced operation in the second quarter of 2015 and has total capacity to ship up to 210,000 barrels per day of crude oil.

Refining

The company owns and operates three refineries, which process predominantly Canadian crude oil. The Strathcona refinery operates lubricating oil production facilities. In addition to crude oil, the company purchases finished products to supplement its refinery production.

In 2016, capital expenditures of about $95 million were made at the company s refineries. Capital expenditures focused mainly on refinery projects to improve reliability, feedstock flexibility, energy efficiency and environmental performance.

The approximate average daily volumes of refinery throughput during the three years ended December 31, 2016, and the daily rated capacities of the refineries as at December 31, 2016 were as follows.

	Refinery throughput (a)			Rated capacities (b)
	Year ended December 31			at December 31
thousands of barrels per day	**2016**	2015	2014	**2016**
Strathcona, Alberta	**168**	181	182	**191**
Sarnia, Ontario	**108**	103	109	**119**
Nanticoke, Ontario	**86**	102	103	**113**
Total	**362**	386	394	**423**

(a) Refinery throughput is the volume of crude oil and feedstocks that is processed in the refinery atmospheric distillation units.
(b) Rated capacities are based on definite specifications as to types of crude oil and feedstocks that are processed in the refinery atmospheric distillation units, the products to be obtained and the refinery process, adjusted to include an estimated allowance for normal maintenance shutdowns. Accordingly, actual capacities may be higher

or lower than rated capacities due to changes in refinery operation and the type of crude oil available for processing.

Refinery throughput averaged 362,000 barrels per day in 2016, compared to 386,000 barrels per day in 2015. Capacity utilization decreased to 86 percent from 92 percent in 2015, reflecting the more significant scope of turnaround maintenance activity in the current year.

In 2015, refinery throughput was 92 percent of capacity, 2 percent lower than the previous year. The lower rate was primarily a result of planned maintenance.

Distribution

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

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Marketing

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

The company supplies petroleum products to the motoring public through Esso-branded retail sites and independent marketers. In 2016, the company completed the sale of its remaining company-owned Esso-branded retail sites completing the conversion to a branded wholesaler operating model. On average during the year, there were more than 1,700 retail sites, which by the end of 2016 were all operating under a branded wholesaler model whereby Imperial supplies fuel to independent third parties who own and operate retail sites in alignment with Esso brand standards.

Imperial sells petroleum products to large industrial and transportation customers, independent marketers, resellers as well as other refiners. The company serves agriculture, residential heating and commercial markets through branded resellers.

The approximate daily volumes of net petroleum products (excluding purchases / sales contracts with the same counterparty) sold during the three years ended December 31, 2016, are set out in the following table.

thousands of barrels per day	**2016**	2015	2014
Gasolines	**261**	247	244
Heating, diesel and jet fuels	**170**	170	179
Heavy fuel oils	**16**	16	22
Lube oils and other products	**37**	45	40
Net petroleum product sales	**484**	478	485

Total Downstream capital expenditures were $190 million in 2016.

Chemical

The company s Chemical operations manufacture and market benzene, aromatic and aliphatic solvents, plasticizer intermediates and polyethylene resin. Its petrochemical and polyethylene manufacturing operations are located in Sarnia, Ontario, adjacent to the company s petroleum refinery.

The company s total sales volumes of petrochemicals during the three years ended December 31, 2016, were as follows.

thousands of tonnes	**2016**	2015	2014
Total sales of petrochemicals	**908**	945	953

Lower sales volumes in 2016 were primarily due to higher plant maintenance and feedstock availability.

Total Chemical capital expenditures were $26 million in 2016.

Research

The approximate total gross research expenditures, before credits, during the three years ended December 31, 2016, were as follows.

millions of Canadian dollars	**2016**	2015	2014
Gross research expenditures, before credits	**195**	195	175

Research expenditures are mainly for developing technologies to improve bitumen recovery, reduce costs and reduce the environmental impact of upstream operations, supporting environmental and process improvements in the refineries, as well as accessing ExxonMobil s research worldwide.

The company has scientific research agreements with affiliates of ExxonMobil, 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.

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In 2016, Imperial completed its Calgary Research Centre in Quarry Park, a state-of-the-art facility focused on oil sands innovation and technology.

Environmental protection

The company regards protecting the environment in connection with its various operations a priority. The company works in cooperation with government agencies, industry associations and communities to address existing, and to anticipate potential, environmental protection issues. In the past five years, the company has made capital and operating expenditures of about $6.1 billion on environmental protection and facilities. In 2016, the company s environmental capital and operating expenditures totalled approximately $0.7 billion, which was spent primarily on water treatment, tailings treatment and emission reductions at company-owned facilities and Syncrude; and on remediation of idled facilities and operations. Capital and operating expenditures relating to environmental protection are expected to be about $0.7 billion in 2017.

Human resources

career employees (a)

	2016	2015	2014
Total	**5,600**	5,700	5,500

(a) Rounded. Career employees are defined as active executive, management, professional, technical, administrative and wage employees who work full time or part time for the company and are covered by the company s benefit plans.

About 7 percent of the company s employees are members of unions.

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. These rights, in the form of leases or licences, are generally acquired for cash or work commitments. A lease or licence entitles the holder to explore for petroleum and/or natural gas on the leased lands for a specified period.

In western provinces, the lease holder can produce the petroleum or natural gas discovered on the leased lands and retains the rights based on continued production. Oil sands leases are retained by meeting the minimum level of evaluation, payment of rentals, or by production.

The holder of a licence relating to Canada lands and the Atlantic offshore can apply for a SDL if a discovery is made. If granted, the SDL holds the lands indefinitely subject to certain conditions. The holder may then apply for a production licence in order to produce petroleum or natural gas from the licenced land.

Crude oil

Production

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

Exports

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

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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 2016 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 royalties for Cold Lake, Syncrude and Kearl, see Upstream section under Item 1.

Investment Canada Act

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

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

Competition Act

The Competition Bureau ensures that Canadian businesses and consumers prosper in a competitive and innovative marketplace. The Competition Bureau is responsible for the administration and enforcement of the Competition Act (the Act). A merger transaction, whether or not notifiable, is subject to examination by the Commissioner of the Competition Bureau to determine whether the merger will have or is likely to have, the effect of preventing or lessening substantially, competition in a definable market. The assessment of the competitive effects of a merger is made with reference to the factors identified under the Act.

An Advance Ruling Certificate (ARC) may be issued by the Commissioner to a party or parties to a proposed merger transaction who want to be assured that the transaction will not give rise to proceedings under section 92 of the Act. Section 102 of the Act provides that an ARC may be issued when the Commissioner is satisfied that there would not be sufficient grounds on which to apply to the Competition Tribunal for an order against a proposed merger. The issuance of an ARC is discretionary. An ARC cannot be issued for a transaction that has been completed, nor does an ARC ensure approval of the transaction by any agency other than the Competition Bureau.

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The company online

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

The public may read and copy any materials the company files with the SEC at the SEC s Public Reference Room at 100 F Street, NE., Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC s website, www.sec.gov, contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Item 1A. Risk factors

Imperial s financial and operating results are subject to a variety of risks inherent in oil, gas and petrochemical businesses. Many of these risk factors are not within Imperial s control and could adversely affect Imperial s business, financial and operating results, or financial position. These risk factors include:

Volatility of commodity prices

The company s operations and earnings may be significantly affected by changes in oil and gas prices and by changes in margins on refined products and petrochemicals. Crude oil, natural gas, petrochemical and product prices and margins depend on local, regional, and global events or conditions that affect supply and demand for the relevant commodity.

Demand related factors which could impact Imperial s results include economic conditions, where periods of low or negative economic growth will typically have an adverse impact on results; technological improvements in energy efficiency; seasonal weather patterns, which affect the demand for energy associated with heating and cooling; increased competitiveness of alternative energy sources; and changes in technology or consumer preferences that affect the market for petroleum products.

Commodity prices and margins also vary depending on a number of factors affecting supply. For example, increased supply from the development of new oil and gas supply sources and technologies to enhance recovery from existing sources tend to reduce commodity prices to the extent such supply increases are not offset by commensurate growth in demand. Similarly, increases in industry refining or petrochemical manufacturing capacity tend to reduce margins on affected products. World oil, gas and petrochemical supply levels can also be affected by factors that reduce available supplies, such as adherence by member countries to Organization of the Petroleum Exporting Countries (OPEC) production quotas and the occurrence of wars, hostile actions, natural disasters, disruptions in competitors operations, or unexpected pipeline constraints that may disrupt supplies. Technological change can also alter the relative costs for competitors to find, produce, and refine oil and gas and to manufacture petrochemicals.

Commodity prices have been volatile, and the company expects that volatility to continue. Any material decline in crude oil prices could have a material adverse effect on Imperial s Upstream operations, financial position, proved reserves and the amount spent to develop reserves.

A significant portion of the company s production is bitumen, which is blended with diluent to create a marketable heavy crude oil. The market price for western Canadian heavy crude oil is typically lower than light and medium grades of oil principally due to the higher transportation and refining costs, and limited refining capacity capable of processing heavy crude oil. Heavy crude oil may also be subject to limits on transportation capacity to markets to a larger extent than light crude oil. Future crude price differentials are uncertain and increases in the heavy crude oil discounts could have a material adverse effect on the company s business. Increases to diluent prices, relative to heavy crude oil prices, could also have an adverse effect on the company s business.

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

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Government and political factors

Imperial s results can be adversely impacted by political or regulatory developments affecting operations. Changes in government policy or regulations, or third party opposition to company or infrastructure projects could impact Imperial s existing operations and planned projects. For example, increases in taxes or government royalty rates (including retroactive claims); changes in environmental regulations or other laws that increase the cost of compliance or reduce or delay available business opportunities; and adoption of regulations mandating the use of alternative fuels or uncompetitive fuel components could affect the company s operations.

Environmental risks

All phases of the Upstream, Downstream and Chemical businesses are subject to environmental regulation pursuant to a variety of Canadian federal, provincial, territorial 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, monitored, 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 cessation of operations, imposition of fines and penalties and liability for clean-up costs and damages.

The costs of complying with environmental legislation in the future could have a material adverse effect on the company s financial condition or results of operations. The company anticipates that changes in environmental legislation may require, among other things, reductions in emissions from its operations to the air and water and may result in increased capital expenditures. Changes in environmental legislation (including, but not limited to, application of regulations related to air, water, land and biodiversity) may increase the cost of compliance or reduce or delay available business opportunities. 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.

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

Climate change and greenhouse gas restrictions

Due to concern over the risk of climate change, a number of provinces and the Government of Canada have adopted, or are considering the adoption of, regulatory frameworks to reduce greenhouse gas (GHG) emissions. These include adoption of carbon emissions pricing, cap and trade regimes, carbon taxes, emissions limits, increased efficiency standards, and incentives or mandates for renewable energy. These requirements could make Imperial s products more expensive, reduce or delay available business opportunities, reduce demand for hydrocarbons, and shift hydrocarbon demand toward lower GHG emission energy sources. Current and pending GHG regulations may also increase compliance and abatement costs, lengthen project implementation times, and affect operations.

Currency

Prices for commodities produced by the company are commonly benchmarked in U.S. dollars. The majority of Imperial s sales and purchases are related to these industry U.S. dollar benchmarks. As the company records and reports its financial results in Canadian dollars, to the extent that the value of the Canadian dollar strengthens, the company s earnings will be negatively affected.

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Other business risks

Imperial is reliant on a number of key chemicals, catalysts and third party service providers, including input and output commodity transportation (pipelines, rail, trucking, marine) and utilities providing services, including electricity and water, to various company operations. The lack of availability and capacity, and proximity of pipeline facilities and railcars could negatively impact Imperial s ability to produce at capacity levels. Transportation disruptions could adversely affect the company s price realizations, refining operations and sales volumes, as well as potentially limit the ability to deliver production to market. A third party utilities outage could have an adverse impact on the company s operations and ability to produce.

Management effectiveness

In addition to external economic and political factors, Imperial s future business results also depend on the company s ability to manage successfully those factors that are at least in part within its control. The extent to which Imperial manages these factors will impact its performance relative to competition. For projects in which the company is not the operator, Imperial depends on the management effectiveness of one or more co-venturers whom the company does not control.

Project management

The company s results are affected by its ability to develop and operate 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.

Operational efficiency

An important component of Imperial s competitive performance, especially given the commodity based nature of Imperial s business, is the ability to operate efficiently, including the company s ability to manage expenses and improve production yields on an ongoing basis. This requires continuous management focus, including technology improvements, cost control, productivity enhancements, regular reappraisal of the company s asset portfolio, and the recruitment, development and retention of high caliber employees.

Research and development

Imperial relies upon the research and development organizations of the company and ExxonMobil, with whom the company conducts shared research. To maintain the company s competitive position, especially in light of the technological nature of Imperial s business and the need for continuous efficiency improvement, research and development organizations must be successful and able to adapt to a changing market and policy environment, including developing technologies to help reduce GHG emissions.

Safety, business controls and environmental risk management

The scope and nature of the company s operations present a variety of significant hazards and risks, including operational hazards and risks such as explosions, fires, pipeline ruptures and crude oil spills. Imperial s operations are also subject to the additional hazards of pollution, releases of toxic gas and environmental hazards and risks, such as severe weather, and geological events. The company s results depend on management s ability to minimize these inherent risks, to effectively control business activities and to minimize the potential for human error. Imperial applies rigorous management systems, including a combined program of effective operations integrity management, ongoing upgrades, key equipment replacements, and comprehensive inspection and surveillance. The company also maintains a disciplined framework of internal controls and applies a controls management system for monitoring compliance with this framework. Substantial liabilities and other adverse impacts could result if the company s management systems and controls do not function as intended.

Business risks also include the risk of cybersecurity breaches. If systems for protecting against cybersecurity risks prove insufficient, the company could be adversely affected such as by having its business systems compromised, its proprietary information altered, lost or stolen, or its business operations disrupted.

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Reserves

The company s future production and cash flows from bitumen, synthetic oil, liquids and natural gas reserves are highly dependent upon the company s success in exploiting its current reserve base. To maintain production and cash flows, the company must continue to replace produced reserves as they are depleted, which can be accomplished through exploration discovery of new resources, appraisal and investments in developing discovered resources, or acquisition of reserves. 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 adversely impacted. 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.

Estimates of economically recoverable oil and natural gas reserves and future net cash flows involve many uncertainties, including factors beyond the company s control. Key factors with uncertainty include: geological and engineering estimates; the assumed effects of regulation by government agencies including royalty frameworks; future commodity prices; and operating costs. Actual production, revenues, taxes, development costs, abandonment costs, and operating expenditures with respect to reserves will likely vary from such estimates, and such variances could be material.

Preparedness

The company s operations may be disrupted by severe weather events, natural disasters, human error, and similar events. Imperial s ability to mitigate the adverse impacts of these events depends in part upon the effectiveness of its rigorous disaster preparedness and response planning, as well as business continuity planning.

Item 1B. Unresolved staff comments

Not applicable.

Item 2. Properties

Reference is made to Item 1 above.

Item 3. Legal proceedings

Not applicable.

Item 4. Mine safety disclosures

Not applicable.

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PART II

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

Market information

The company s common shares trade on the Toronto Stock Exchange and the NYSE MKT LLC. Reference is made to the Quarterly financial and stock trading data portion of the Financial section on page 85 of this report. The closing price for Imperial Oil Limited common shares on the Toronto Stock Exchange was $42.30 as at February 8, 2017.

Dividends

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

	2016				2015			
Canadian dollars	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Declared dividend per share	**0.15**	**0.15**	**0.15**	**0.14**	0.14	0.14	0.13	0.13

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 non-resident withholding tax of 15 percent, but may vary from one tax convention to another.

The withholding tax is reduced to 5 percent on dividends paid to a corporation resident in the U.S. that owns at least 10 percent of the voting shares of the company.

The company is a qualified foreign corporation for purposes of the reduced U.S. capital gains tax rates, 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 non-residents not carrying on business in Canada, as long as the shareholder does not, in any given 60 month period, own 25 percent or more of the shares of the company.

As of February 8, 2017 there were 11,238 holders of record of common shares of the company.

Between October 1, 2016 and December 31, 2016, pursuant to the company s restricted stock unit plan, 400 shares were issued to employees outside the U.S. in reliance on Regulation S under the Securities Act, and 650 shares were issued to a seconded employee in reliance on the section 4(a)(2) exemption under the Securities Act.

Securities authorized for issuance under equity compensation plans

Sections of the company s management proxy circular are contained in the Proxy information section, starting on page 86. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

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

- Entitled Performance graph within the Compensation discussion and analysis section on page 141 of this report; and

- Entitled Equity compensation plan information , within the Compensation discussion and analysis , on page 146 of this report.

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Issuer purchases of equity securities

	Total number of shares purchased	Average price paid per share (Canadian dollars)	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or programs (a)
October 2016 (October 1 October 31)	**-**	**-**	**-**	**1,000,000**
November 2016 (November 1 - November 30)	**-**	**-**	**-**	**1,000,000**
December 2016 (December 1 - December 31)	**1,050**	**48.09**	**1,050**	**998,950**

(a) On June 22, 2016, 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 1,000,000 common shares during the period June 27, 2016 to June 26, 2017. The program will end when the company has purchased the maximum allowable number of shares, or on June 26, 2017.

Item 6. Selected financial data

millions of Canadian dollars	**2016**	2015	2014	2013	2012
Operating revenues	**25,049**	26,756	36,231	32,722	31,053
Net income (loss)	**2,165**	1,122	3,785	2,828	3,766
Total assets at year-end	**41,654**	43,170	40,830	37,218	29,364
Long-term debt at year-end	**5,032**	6,564	4,913	4,444	1,175
Total debt at year-end	**5,234**	8,516	6,891	6,287	1,647
Other long-term obligations at year-end	**3,656**	3,597	3,565	3,091	3,983
Canadian dollars					
Net income (loss) per share - basic	**2.55**	1.32	4.47	3.34	4.44
Net income (loss) per share - diluted	**2.55**	1.32	4.45	3.32	4.42
Dividends declared	**0.59**	0.54	0.52	0.49	0.48

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

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

Reference is made to the section entitled Management s discussion and analysis of financial condition and results of operations in the Financial section, starting on page 34 of this report.

Item 7A. Quantitative and qualitative disclosures about market risk

Reference is made to the section entitled Market risks and other uncertainties in the Financial section, starting on page 44 of this report. All statements other than historical information incorporated in this Item 7A are forward-looking statements. The actual impact of future market changes could differ materially due to, among other things, factors discussed in this report.

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Item 8. Financial statements and supplementary data

Reference is made to the table of contents in the Financial section on page 30 of this report:

Consolidated financial statements, together with the report thereon of PricewaterhouseCoopers LLP (PwC) dated February 22, 2017 beginning with the section entitled Report of independent registered public accounting firm on page 52 and continuing through note 17, Other comprehensive income (loss) information on page 80;

Supplemental information on oil and gas exploration and production activities (unaudited) starting on page 81; and

Quarterly financial and stock trading data (unaudited) on page 85.

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, 2016. Based on that evaluation, these officers have concluded that the company s disclosure controls and procedures are effective in ensuring that information required to be disclosed by the company in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to them in a manner that allows for timely decisions regarding required disclosures and are effective in ensuring that such information is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms.

Reference is made to page 51 of this report for Management s report on internal control over financial reporting and page 52 for the Report of independent registered public accounting firm on the company s internal control over financial reporting as of December 31, 2016.

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, executive officers and corporate governance

Sections of the company s management proxy circular are contained in the Proxy information section, starting on page 86. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

The company currently has seven directors. The articles of the company require that the board have between five and fifteen directors. Each director is elected to hold office until the close of the next annual meeting. Each of the seven individuals listed in the section entitled Director nominee information on pages 87 to 95 of this report have been nominated for election at the annual meeting of shareholders to be held April 28, 2017. All of the nominees are directors and have been since the dates indicated.

Reference is made to the section under Director nominee information :

Director nominee tables , on pages 87 to 95 of this report;

Reference is made to the sections under Corporate governance disclosure :

Other public company directorships of our board nominees , on page 102 of this report.

The table entitled Audit committee under Board and committee structure , on page 106 of this report;

Ethical business conduct , starting on page 118 of this report; and

Largest shareholder , on page 120 of this report.

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

Named executive officers of the company and Other executive officers of the company , on pages 121 to 123 of this report.

Item 11. Executive compensation

Sections of the company s management proxy circular are contained in the Proxy information section, starting on page 86. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

Reference is made to the sections under Corporate governance disclosure :

- Board of director compensation , on pages 110 to 116 of this report; and

- Share ownership guidelines of independent directors and chairman, president and chief executive officer , on page 117 of this report.

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

- Letter to Shareholders from the executive resources committee on executive compensation , starting on page 124 of this report; and

- Compensation discussion and analysis , on pages 126 to 147 of this report.

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

Sections of the company s management proxy circular are contained in the Proxy information section, starting on page 86. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

Reference is made to the section under Company executives and executive compensation entitled Equity compensation plan information , within the Compensation discussion and analysis section, on page 146 of this report.

Reference is made to the section under Corporate governance disclosure entitled Largest shareholder , on page 120 of this report.

Reference is also made to the security ownership information for directors and executive officers of the company under the preceding Items 10 and 11. With respect to named executive officers who are not directors of the company, as of February 8, 2017, B.A. Babcock was the owner of 25,539 common shares of the company and held 111,500 restricted stock units of the company. B.P. Cahir held 32,400 restricted stock units of the company. W.J. Hartnett was the owner of 14,925 common shares of the company and held 96,800 restricted stock units of the company. T.B. Redburn was the owner of 3,215 common shares of the company and held 76,950 restricted stock units of the company.

The directors and the executive officers of the company, whose compensation for the year-ended December 31, 2016 is described in the sections under Director nominee information starting on page 87 and Company executives and executive compensation starting on page 121, consist of 18 persons, who, as a group, as of February 8, 2017, beneficially own 161,024 common shares of the company, being approximately 0.02 percent of the total number of outstanding shares of the company, and 457,483 shares of Exxon Mobil Corporation (including 398,050 restricted shares). This information not being within the knowledge of the company has been provided by the directors and the executive officers individually. As a group, the directors and executive officers of the company held restricted stock units to acquire 724,758 common shares of the company, as of February 8, 2017.

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

Sections of the company s management proxy circular are contained in the Proxy information section, starting on page 86. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

Reference is made to the section under Corporate governance disclosure entitled Independence of our board nominees , on page 99 of this report.

Reference is made to the section under Corporate governance disclosure entitled Transactions with Exxon Mobil Corporation , on page 120 of this report.

D.G. (Jerry) Wascom is deemed a non-independent member of the board of directors and the executive resources committee, environmental, health and safety committee, nominations and corporate governance committee and contributions committee under the relevant standards. As an employee of ExxonMobil Refining & Supply Company, D.G. (Jerry) Wascom 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 information

The audit committee of the board of directors recommends that PricewaterhouseCoopers LLP (PwC) be reappointed as the auditor of the company until the close of the next annual meeting. PwC have been the auditor of the company for more than five years and are located in Calgary, Alberta. PwC are a participating audit firm with the Canadian Public Accountability Board.

Auditor fees

The aggregate fees of PwC for professional services rendered for the audit of the company s financial statements and other services for the fiscal years ended December 31, 2016 and December 31, 2015 were as follows:

thousands of Canadian dollars	**2016**	2015
Audit fees	**1,500**	1,416
Audit-related fees	**104**	107
Tax fees	**-**	-
All other fees	**-**	-
Total fees	**1,604**	1,523

Audit fees included the audit of the company s annual financial statements, internal control over financial reporting, and a review of the first three quarterly financial statements in 2016. Audit-related fees consisted of other assurance services including the audit of the company s retirement plan and royalty statement audits for oil and gas producing entities. The company did not engage the auditor for any other services.

The audit committee formally and annually evaluates the performance of the external auditor, recommends the external auditor to be appointed by the shareholders, fixes their remuneration and oversees their 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.

Auditor independence

The audit committee continually discusses with PwC their independence from the company and from management. PwC have confirmed that they are independent with respect to the company within the meaning of the Rules of Professional Conduct of the Institute of Chartered Professional Accountants of Alberta and the rules of the U.S. Securities and Exchange Commission. The company has concluded that the auditor s independence has been maintained.

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PART IV

Item 15. Exhibits, financial statement schedules

Reference is made to the table of contents in the Financial section on page 30 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)).

(10) (ii) (1) 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)).

(2) 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)).

(3) 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)).

(4) 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)).

(5) 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)).

(6) 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)).

(7) 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)).

(8) 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)).

(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) 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)).

(3) 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)).

(4) Short Term Incentive Program for selected executives effective February 2, 2012 (Incorporated herein by reference to Exhibit 9.01(c)[10(iii)(A)(1)] of the company s Form 8-K filed on February 7, 2012 (File No. 0-12014)).

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	(5)	Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2011 and subsequent years, as amended effective November 14, 2011 (Incorporated herein by reference to Exhibit 9.01(c)[10(iii)(A)(1)] of the company s Form 8-K filed on February 23, 2012 (File No. 0-12014)).
	(6)	Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2016 and subsequent years, as amended effective October 26, 2016 (Incorporated herein by reference to Exhibit 9.01(c)[10(iii)(A)(1)] of the company s Form 8-K filed on October 31, 2016 (File No. 0-12014)).
	(7)	Amended Short Term Incentive Program with respect to awards granted in 2016 and subsequent years, as amended effective October 26, 2016 (Incorporated herein by reference to Exhibit 9.01(c)[10(iii)(A)(1)] of the company s Form 8-K filed on October 31, 2016 (File No. 0-12014)).
(21)		Imperial Oil Resources Limited, McColl-Frontenac Petroleum ULC 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, 2016.
(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, 505 Quarry Park Boulevard S.E., Calgary, Alberta T2C 5N1, and payment of processing and mailing costs.

Item 16. Form 10-K summary

Not applicable.

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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 22, 2017 by the undersigned, thereunto duly authorized.

Imperial Oil Limited

by */s/ Richard M. Kruger*
(Richard M. Kruger)
Chairman, president and chief executive officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 22, 2017 by the following persons on behalf of the registrant and in the capacities indicated.

Signature	Title
/s/ Richard M. Kruger (Richard M. Kruger)	Chairman, president and chief executive officer and director (Principal executive officer)
/s/ Beverley A. Babcock (Beverley A. Babcock)	Senior vice-president, finance and administration, and controller (Principal financial officer and principal accounting officer)
/s/ Krystyna T. Hoeg (Krystyna T. Hoeg)	Director
/s/ Jack M. Mintz (Jack M. Mintz)	Director
/s/ David S. Sutherland (David S. Sutherland)	Director
/s/ D.G. (Jerry) Wascom (D.G. (Jerry) Wascom)	Director
/s/ Sheelagh D. Whittaker (Sheelagh D. Whittaker)	Director

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

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Financial section

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Financial information (U.S. GAAP)

millions of Canadian dollars	**2016**	2015	2014	2013	2012
Operating revenues	**25,049**	26,756	36,231	32,722	31,053
Net income (loss) by segment:					
Upstream	**(661)**	(704)	2,059	1,712	1,888
Downstream	**2,754**	1,586	1,594	1,052	1,772
Chemical	**187**	287	229	162	165
Corporate and Other	**(115)**	(47)	(97)	(98)	(59)
Net income (loss)	**2,165**	1,122	3,785	2,828	3,766
Cash and cash equivalents at year-end	**391**	203	215	272	482
Total assets at year-end	**41,654**	43,170	40,830	37,218	29,364
Long-term debt at year-end	**5,032**	6,564	4,913	4,444	1,175
Total debt at year-end	**5,234**	8,516	6,891	6,287	1,647
Other long-term obligations at year-end	**3,656**	3,597	3,565	3,091	3,983
Shareholders equity at year-end	**25,021**	23,425	22,530	19,524	16,377
Cash flow from operating activities	**2,015**	2,167	4,405	3,292	4,680
Per-share information (dollars)					
Net income (loss) per share - basic	**2.55**	1.32	4.47	3.34	4.44
Net income (loss) per share - diluted	**2.55**	1.32	4.45	3.32	4.42
Dividends declared	**0.59**	0.54	0.52	0.49	0.48

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Frequently used terms

Listed below are definitions of several of Imperial s key business and financial performance measures. The definitions are provided to facilitate understanding of the terms and how they are calculated.

Capital employed

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

millions of Canadian dollars	**2016**	2015	2014
Business uses: asset and liability perspective			
Total assets	**41,654**	43,170	40,830
Less: total current liabilities excluding notes and loans payable	**(3,681)**	(3,441)	(4,003)
total long-term liabilities excluding long-term debt	**(7,718)**	(7,788)	(7,406)
Add: Imperial s share of equity company debt	**17**	18	19
Total capital employed	**30,272**	31,959	29,440
Total company sources: debt and equity perspective			
Notes and loans payable	**202**	1,952	1,978
Long-term debt	**5,032**	6,564	4,913
Shareholders equity	**25,021**	23,425	22,530
Add: Imperial s share of equity company debt	**17**	18	19
Total capital employed	**30,272**	31,959	29,440

Return on average capital employed (ROCE)

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

millions of Canadian dollars	**2016**	2015	2014
Net income	**2,165**	1,122	3,785
Financing costs (after tax), including Imperial s share of equity companies	**53**	30	1
Net income excluding financing costs	**2,218**	1,152	3,786
Average capital employed	**31,116**	30,700	27,637
Return on average capital employed (percent) corporate total	**7.1**	3.8	13.7

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Cash flow from operating activities and asset sales

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

millions of Canadian dollars	**2016**	2015	2014
Cash from operating activities	**2,015**	2,167	4,405
Proceeds from asset sales	**3,021**	142	851
Total cash flow from operating activities and asset sales	**5,036**	2,309	5,256

Operating costs

Operating costs are the costs during the period to produce, manufacture, and otherwise prepare the company s products for sale including energy costs, staffing and maintenance costs. They exclude the cost of raw materials, taxes and interest expense and are on a before-tax basis. While the company is responsible for all revenue and expense elements of net income, operating costs represent the expenses most directly under the company s control and therefore, are useful in evaluating the company s performance.

Reconciliation of operating costs

millions of Canadian dollars	**2016**	2015	2014
From Imperial s consolidated statement of income			
Total expenses	**24,910**	24,965	31,945
Less:			
Purchases of crude oil and products	**15,120**	15,284	22,479
Federal excise tax	**1,650**	1,568	1,562
Financing costs	**65**	39	4
Subtotal	**16,835**	16,891	24,045
Imperial s share of equity company expenses	**63**	40	39
Total operating costs	**8,138**	8,114	7,939

Components of operating costs

millions of Canadian dollars	**2016**	2015	2014
From Imperial s consolidated statement of income			
Production and manufacturing	**5,224**	5,434	5,662
Selling and general	**1,129**	1,117	1,075
Depreciation and depletion	**1,628**	1,450	1,096
Exploration	**94**	73	67
Subtotal	**8,075**	8,074	7,900
Imperial s share of equity company expenses	**63**	40	39
Total operating costs	**8,138**	8,114	7,939

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

Overview

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

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

Imperial, with its resource base, financial strength, disciplined investment approach and technology portfolio, is well-positioned to participate in substantial investments to develop new Canadian energy supplies. The company s integrated business model, with significant investments in Upstream, Downstream and Chemical segments, reduces the company s risk from changes in commodity prices. While commodity prices are 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. Major investment opportunities are tested over a wide range of economic scenarios. Once major investments are made, a reappraisal process is completed to ensure relevant lessons are learned and improvements are incorporated into future projects.

The term project as used in this report can refer to a variety of different activities and does not necessarily have the same meaning as in any government payment transparency reports.

Business environment and risk assessment

Long-term business outlook

By 2040, the world s population is projected to grow to approximately nine billion people, or about 1.8 billion more people than in 2015. Coincident with this population increase, the company expects worldwide economic growth to average close to 3 percent per year. As economies and populations grow, and as living standards improve for billions of people, the need for energy will continue to rise. Even with significant efficiency gains, global energy demand is projected to rise by about 25 percent from 2015 to 2040. This demand increase is expected to be concentrated in developing countries (i.e., those that are not member nations of the Organization for Economic Cooperation and Development). Canada is expected to see flat to modest local energy demand growth through to 2040 and will continue to be a large supplier of energy exports to help meet rising global energy needs.

As expanding prosperity drives global energy demand higher, increasing use of energy-efficient technologies and practices as well as lower-emission fuels will continue to help significantly reduce energy consumption and emissions per unit of economic output over time. Substantial efficiency gains are likely in all key aspects of the world economy through 2040, affecting energy requirements for transportation, power generation, industrial applications and residential and commercial needs.

Energy for global transportation including cars, trucks, ships, trains and airplanes is expected to increase by about 25 percent from 2015 to 2040. The growth in transportation energy demand is likely to account for approximately 60 percent of the growth in liquid fuels demand worldwide over this period. Nearly all the world s transportation fleets will continue to run on liquid fuels, which are abundant, widely available, easy to transport and provide a large quantity of energy in small volumes.

Demand for electricity around the world is likely to increase approximately 60 percent from 2015 to 2040, led by a doubling of demand in developing countries. Consistent with this projection, power generation is expected to remain the largest and fastest-growing major segment of global energy demand. Meeting the expected growth in power demand will require a diverse set of energy sources. In 2015 coal-fired generation provided about 40 percent of the world s electricity, however by 2040 coal-fired generation is likely to decline to less than 30 percent, in part as a result of policies to improve air quality as well as reduce greenhouse gas emissions to address the risks of climate change. From 2015 to 2040, the amount of electricity generated using natural gas, nuclear power, and renewables is likely to approximately double, and account for 90 percent of the growth in electricity supplies. By 2040, coal, natural gas and renewables are projected to each generate a similar share of electricity worldwide, although significant differences will exist across regions reflecting a wide range of factors including the cost and availability of energy types.

Liquid fuels provide the largest share of global energy supplies today due to their broad-based availability, affordability, ease of distribution and storage. By 2040, global demand for liquid fuels is expected to grow to approximately 112 million barrels of oil-equivalent per day, an increase of almost 20 percent from 2015. Globally, crude production from traditional conventional sources will likely decline slightly through 2040, with significant development activity mostly offsetting natural declines from these fields. However, this decline is expected to be more than offset by rising production from a wide variety of emerging supply sources including tight oil, deep-water, oil sands, natural gas liquids and biofuels. The world s resource base is sufficient to meet projected demand through 2040 as technology advances continue to expand the availability of economic supply options. However, access to resources and timely investments will remain critical to meeting global needs with reliable, affordable supplies.

Natural gas is a versatile fuel, suitable for a wide variety of applications and it is expected to be the fastest-growing major fuel source from 2015 to 2040, meeting about 40 percent of energy demand growth. Global demand is expected to rise about 45 percent from 2015 to 2040, with about 45 percent of that increase in the Asia Pacific region. Helping meet these needs will lead to significant growth in supplies of unconventional gas - the natural gas found in shale and other rock formations that was once considered uneconomic to produce. In total, about 60 percent of the growth in natural gas supplies is expected to be from unconventional sources. However, it is expected conventionally-produced natural gas will remain the cornerstone of supply, meeting about two-thirds of global demand in 2040. Worldwide liquefied natural gas (LNG) trade will expand significantly, likely reaching more than 2.5 times the level of 2015 by 2040, with much of this supply expected to meet rising demand in Asia Pacific.

The world s energy mix is highly diverse and will remain so through 2040. Oil is expected to remain the largest source of energy with its share remaining close to one-third in 2040. Coal is currently the second largest source of energy, but it is likely to lose that position to natural gas in the 2025 to 2030 timeframe. The share of natural gas is expected to reach 25 percent by 2040, while the share of coal falls to about 20 percent. Nuclear power is projected to grow significantly, as many nations are likely to expand nuclear capacity to address rising electricity needs as well as energy security and environmental issues. Total renewable energy is likely to reach about 15 percent of total energy by 2040, with biomass, hydro and geothermal contributing a combined share of more than 10 percent. Total energy supplied from wind, solar and biofuels is expected to increase rapidly, growing over 200 percent from 2015 to 2040, when they will approach 4 percent of the world s energy.

The company anticipates that the world s available oil and gas resource base will grow not only from new discoveries but also from reserve increases in previously discovered fields. Technology will underpin these increases. The cost to develop and supply these resources will be significant. According to the International Energy Agency, the investment required to meet oil and natural gas supply requirements worldwide over the period 2016 to 2040 will be about US$23 trillion (measured in 2015 dollars) or approximately US$900 billion per year on average.

International accords and underlying regional and national regulations covering greenhouse gas emissions continue to evolve with uncertain timing and outcome, making it difficult to predict their business impact. Imperial s estimate of potential costs related to possible public policies covering energy-related greenhouse gas emissions are consistent with those outlined in ExxonMobil s long-term *Outlook for Energy*, which is used as a foundation for assessing the business environment and Imperial s investment evaluations.

The information provided in the long-term business outlook includes internal estimates and forecasts based upon internal data and analyses as well as publicly available information from external sources including the International Energy Agency.

Upstream

Imperial produces crude oil and natural gas for sale predominantly into the North American markets. Imperial s Upstream business strategies guide the company s exploration, development, production, research and gas marketing activities. These strategies include capturing material and accretive opportunities to

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continually high-grade the resource portfolio, exercising a disciplined approach to investing and cost management, developing and applying high-impact technologies, pursuing productivity and efficiency gains, and growing profitable oil and gas production. These strategies are underpinned by a relentless focus on operational excellence, commitment to innovative technologies, development of employees and investment in the communities within which the company operates.

Imperial has a significant oil and gas resource base and a large inventory of potential projects. The company continues to evaluate opportunities to support the company s long-term growth. Actual volumes will vary from year to year due to the factors described in Item 1A. Risk factors.

Prices for most of the company s crude oil sold are referenced to West Texas Intermediate (WTI) and Western Canada Select (WCS) oil markets. In 2016, the average WTI and WCS crude oil prices, in U.S. dollars, were lower versus 2015. The upstream industry environment has been challenged in recent years with abundant crude oil supply causing crude oil prices to decrease to levels not seen since 2004. However, current market conditions are not necessarily indicative of future conditions. The markets for crude oil and natural gas have a history of significant price volatility. Imperial believes prices over the long term will continue to be driven by market supply and demand, with the demand side largely being a function of global economic growth. On the supply side, prices may be significantly impacted by political events, the actions of OPEC and other large government resource owners, and other factors. To manage the risks associated with price, Imperial evaluates annual plans and all major investments across a range of price scenarios.

Downstream

Imperial s Downstream serves predominantly Canadian markets with refining, logistics and marketing assets. Imperial s Downstream business strategies guide the company s activities. These strategies include targeting best-in-class operations in all aspects of the business, maximizing value from advanced technologies, capitalizing on integration across Imperial s businesses, selectively investing for resilient and advantaged returns, operating efficiently and effectively, and providing valued products and services to customers.

Imperial owns and operates three refineries in Canada, with aggregate distillation capacity of 423,000 barrels per day. Imperial s fuels marketing business across Canada serves customers through more than 1,700 Esso-branded retail sites, as well as wholesale and industrial operations through a network of primary distribution terminals.

Refining margins are largely driven by differences in commodity prices and are a function of the difference between what a refinery pays for its raw materials (primarily crude oil) and market prices for the range of products produced (primarily gasoline, heating oil, diesel oil, jet fuel and fuel oil). Crude oil and many products are widely traded with published prices, including those quoted on the New York Mercantile Exchange. Prices for these commodities are determined by global and regional marketplaces and are influenced by many factors, including supply/demand balances, inventory levels, industry refinery operations, import / export balances, currency fluctuations, seasonal demand, weather and political climate.

While demand remained strong in 2016, margins weakened as surplus distillate and gasoline production capacity created higher inventory. North American refineries have benefitted from cost-competitive feedstock and energy supplies, but that benefit decreased in 2016.

Imperial s long-term outlook is that the North American refining industry will remain subject to intense competition. Additionally, as described in more detail in Item 1A. Risk Factors, proposed carbon policy and other climate-related regulations, as well as the continued growth in biofuels mandates, could have negative impacts on the downstream business. Imperial s integration across the value chain, from refining to marketing, enhances overall value in both fuels and lubricants businesses.

The company supplies petroleum products to the motoring public through Esso-branded retail sites and independent marketers. In 2016, the company completed the sale of its remaining company-owned Esso-branded retail sites completing the conversion to a branded wholesaler operating model. On average during the year, there were more than 1,700 retail sites, which by the end of 2016 were all operating under a branded wholesaler model whereby Imperial supplies fuel to independent third parties who own and operate retail sites in alignment with Esso brand standards.

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Chemical

In North America, unconventional natural gas continued to provide advantaged ethane feedstock for steam crackers and a favourable margin environment for integrated chemical producers. The company s strategy for its Chemical business is to reduce costs and maximize value by continuing the integration of its chemical plant in Sarnia with the refinery. The company also benefits from its integration within ExxonMobil s North American chemical businesses, enabling Imperial to maintain a leadership position in its key market segments.

Results of operations

Consolidated

millions of Canadian dollars	**2016**	2015	2014
Net income (loss)	**2,165**	1,122	3,785

2016

Net income in 2016 was $2,165 million, or $2.55 per-share on a diluted basis, including a gain of $1.7 billion ($2.01 per-share) from the sale of retail sites, versus net income of $1,122 million or $1.32 per-share in 2015. Downstream net income was $2,754 million, up from $1,586 million in 2015. Chemical net income was $187 million. Upstream recorded a net loss of $661 million in 2016, compared to a net loss of $704 million in 2015.

2015

Net income in 2015 was $1,122 million, or $1.32 per share on a diluted basis, versus $3,785 million or $4.45 per share in 2014. Upstream recorded a net loss of $704 million, compared to a net income of $2,059 million in 2014. Downstream earnings decreased by $8 million and Chemical earnings increased by $58 million.

Upstream

millions of Canadian dollars	**2016**	2015	2014
Net income (loss)	**(661)**	(704)	2,059

2016

Upstream recorded a net loss of $661 million in 2016, compared to a net loss of $704 million in 2015. The loss in 2016 reflected lower realizations of about $700 million, the impact of the northern Alberta wildfires of about $155 million and higher depreciation expense of about $120 million. These factors were partially offset by higher volumes of about $320 million, the impact of a weaker Canadian dollar of about $130 million, the favorable impact of lower royalties of about $80 million, lower field operating costs of about $80 million and lower energy cost of about

$50 million. The loss in 2015 reflected the impact associated with the Alberta corporate income tax rate increase of $327 million.

2015

Upstream recorded a net loss of $704 million in 2015, compared to net income of $2,059 million in the same period of 2014. Earnings in 2015 reflected lower crude oil and gas realizations of about $3,790 million, a net charge of $327 million associated with increased Alberta corporate income taxes, higher depreciation expense of about $180 million, lower liquids and gas volumes of about $80 million reflecting the impact of divested properties in the prior year and a net charge of about $60 million associated with the inventory carrying value. These factors were partially offset by the impact of a weaker Canadian dollar of about $770 million, the favourable impact of lower royalties of about $700 million, higher volumes from Kearl and Cold Lake of about $670 million and lower energy costs of about $140 million.

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Average realizations

Canadian dollars	**2016**	2015	2014
Bitumen realizations (per barrel)	**26.52**	32.48	67.20
Synthetic oil realizations (per barrel)	**57.12**	61.33	99.58
Conventional crude oil realizations (per barrel)	**32.93**	36.58	76.03
Natural gas liquids realizations (per barrel)	**15.58**	14.70	49.11
Natural gas realizations (per thousand cubic feet)	**2.41**	2.78	4.54

2016

West Texas Intermediate averaged US$43.44 per barrel in 2016, down from US$48.83 per barrel in 2015. Western Canada Select averaged US$29.49 per barrel and US$35.34 per barrel respectively for the same periods. The WTI / WCS differential widened to 32 percent in 2016, up from 28 percent in 2015. The Canadian dollar averaged US$0.75 in 2016, a decrease of US$0.03 from 2015.

Imperial s average Canadian dollar realizations for bitumen and synthetic crudes declined essentially in line with the North American benchmarks, adjusted for changes in the exchange rate and transportation costs. Bitumen realizations averaged $26.52 for 2016, a decrease of $5.96 per barrel from 2015. Synthetic crude realizations averaged $57.12 per barrel, a decrease of $4.21 per barrel from 2015.

2015

The average price for WTI, the main benchmark crude for North America, decreased by 47 percent compared to the same period in 2014. The company s average Canadian dollar realizations for synthetic crude oil and bitumen decreased about 38 and 52 percent in 2015 to $61.33 and $32.48 per barrel respectively, as the decline in benchmark crude and increased light-heavy differentials were partially offset by the weaker Canadian dollar. The company s average realizations on sales of natural gas of $2.78 per thousand cubic feet in 2015 were lower by $1.76 per thousand cubic feet, versus 2014.

Crude oil and NGLs - production and sales (a)

thousands of barrels per day	**2016**		2015		2014	
	gross	**net**	gross	net	gross	net
Bitumen	**281**	**256**	266	245	197	161
Synthetic oil (b)	**68**	**67**	62	58	64	60
Conventional crude oil	**14**	**12**	15	14	18	14
Total crude oil production	**363**	**335**	343	317	279	235
NGLs available for sale	**1**	**1**	1	1	3	2

Total crude oil and NGL production	**364**	**336**	344	318	282	237
Bitumen sales, including diluent (c)	**374**		349		259	
NGL sales	**5**		5		8	

Natural gas - production and production available for sale (d)

millions of cubic feet per day	**2016**		2015		2014	
	gross	**net**	gross	net	gross	net
Production (e) (f)	**129**	**122**	130	125	168	156
Production available for sale (g)		**87**		94		124

(a) Barrels per day metric is calculated by dividing the volume for the period by the number of calendar days in the period. Gross production is the company s share of production (excluding purchases) before deduction of the mineral owners or governments share or both. Net production excludes those shares.

(b) The company s synthetic oil production volumes were from the company s share of production volumes in the Syncrude joint venture.

(c) Diluent is natural gas condensate or other light hydrocarbons added to crude bitumen to facilitate transportation to market by pipeline and rail.

(d) Cubic feet per day metric is calculated by dividing the volume for the period by the number of calendar days in the period.

(e) Gross production of natural gas includes amounts used for internal consumption with the exception of the amounts re-injected.

(f) Net production is gross production less the mineral owners or governments share or both. Net production reported in the above table is consistent with production quantities in the net proved reserves disclosure.

(g) Includes sales of the company s share of net production and excludes amounts used for internal consumption.

2016

Gross production of Cold Lake bitumen averaged 161,000 barrels per day in 2016, up from 158,000 barrels per day in 2015.

Gross production of Kearl bitumen averaged 169,000 barrels per day in 2016 (120,000 barrels Imperial s share) compared to 152,000 barrels per day (108,000 barrels Imperial s share) in 2015. The increase was the result of start-up of the expansion project.

During 2016, the company s share of gross production from Syncrude averaged 68,000 barrels per day, up from 62,000 barrels per day in 2015. Increased production reflects continued efforts to improve the reliability of operations, which more than offset the impact of the Alberta wildfires.

2015

Gross production of Cold Lake bitumen averaged 158,000 barrels per day in 2015, up from 146,000 barrels from the same period last year, with new production from Nabiye offsetting cycle timing of the base operations.

Gross production of Kearl bitumen averaged 152,000 barrels per day during 2015 (108,000 barrels Imperial s share) up from 72,000 barrels per day (51,000 barrels Imperial s share) in 2014, reflecting early start-up of the Kearl expansion project and improved reliability of the initial development.

During 2015, the company s share of gross production from Syncrude averaged 62,000 barrels per day, compared to 64,000 barrels in 2014.

Gross production of conventional crude oil averaged 15,000 barrels per day during 2015, compared to 18,000 barrels in 2014. The lower production volume was primarily due to the impact of properties divested during the first half of 2014.

Gross production of natural gas during 2015 was 130 million cubic feet per day, down from 168 million cubic feet in the same period last year, reflecting the impact of divested properties and natural reservoir decline.

Downstream

millions of Canadian dollars	**2016**	2015	2014
Net income (loss)	**2,754**	1,586	1,594

2016

Downstream net income was $2,754 million, up from $1,586 million in 2015. Earnings increased mainly due to a gain of $1,841 million from the sale of retail sites and the general aviation business, the impact of a weaker Canadian dollar of about $130 million, higher marketing sales volumes of $50 million, partially offset by lower downstream margins of about $910 million.

2015

Downstream net income was $1,586 million, compared to $1,594 million in the same period of 2014. Earnings decreased due to the impact of lower refinery margins of about $590 million and higher operating costs of about $70 million mainly associated with the Edmonton rail terminal. These factors were partially offset by the favourable impact of a weaker Canadian dollar of about $390 million, higher fuels marketing margins and volumes of about $170 million, lower energy costs of about $80 million and a 2015 gain of $17 million from the sale of assets.

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Refinery utilization

thousands of barrels per day (a)	**2016**	2015	2014
Total refinery throughput (b)	**362**	386	394
Refinery capacity at December 31	**423**	421	421
Utilization of total refinery capacity (percent)	**86**	92	94

Sales

thousands of barrels per day (a)	**2016**	2015	2014
Gasolines	**261**	247	244
Heating, diesel and jet fuels	**170**	170	179
Heavy fuel oils	**16**	16	22
Lube oils and other products	**37**	45	40
Net petroleum product sales	**484**	478	485

(a) Volumes per day are calculated by dividing total volumes for the year by the number of calendar days in the year.
(b) Crude oil and feedstocks sent directly to atmospheric distillation units.

2016

Refinery throughput averaged 362,000 barrels per day in 2016, compared to 386,000 barrels per day in 2015. Capacity utilization decreased to 86 percent from 92 percent in 2015, reflecting the more significant scope of turnaround maintenance activity in the current year. Petroleum product sales were 484,000 barrels per day in 2016, up from 478,000 barrels per day in 2015. Sales growth was driven by the company s focus on establishing long-term supply agreements.

2015

Total refinery throughput was 386,000 barrels per day. Refinery throughput was 92 percent of capacity in 2015, 2 percent lower than the previous year. The lower rate was primarily a result of planned maintenance. Total net petroleum sales decreased to 478,000 barrels per day, compared with 485,000 barrels in 2014.

Chemical

millions of Canadian dollars	**2016**	2015	2014
Net income (loss)	**187**	287	229

Sales

thousands of tonnes	**2016**	2015	2014
Polymers and basic chemicals	**697**	735	741
Intermediate and others	**211**	210	212
Total petrochemical sales	**908**	945	953

2016

Chemical net income was $187 million, compared to $287 million in the same period of 2015, mainly due to weaker margins across all major product lines and lower volumes.

2015

Chemical net income was a record $287 million in 2015, an increase of $58 million over the same period in 2014, primarily due to the impact of a weaker Canadian dollar, lower feedstock costs and higher sales of polyethylene.

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Corporate and Other

millions of Canadian dollars	**2016**	2015	2014
Net income (loss)	**(115)**	(47)	(97)

2016

In 2016, net income effects from Corporate and Other were negative $115 million, versus negative $47 million in 2015, primarily due to higher share-based compensation charges, the absence of the impact from the Alberta tax rate increase in 2015 and lower capitalized interest.

2015

In 2015, net income effects from Corporate and Other were negative $47 million, compared to negative $97 million in 2014, primarily due to lower share-based compensation charges and the impact of the Alberta corporate income tax rate increase.

Liquidity and capital resources

Sources and uses of cash

millions of Canadian dollars	**2016**	2015	2014
Cash provided by (used in)			
Operating activities	**2,015**	2,167	4,405
Investing activities	**1,947**	(2,884)	(4,562)
Financing activities	**(3,774)**	705	100
Increase (decrease) in cash and cash equivalents	**188**	(12)	(57)
Cash and cash equivalents at end of year	**391**	203	215

The company issues long-term debt from time to time and maintains a commercial paper program. However internally generated funds cover the majority of its financial requirements. Cash that may be temporarily surplus to the company s immediate needs is carefully managed through counterparty quality and investment guidelines to ensure that it is secure and readily available to meet the company s cash requirements and to optimize returns.

Cash flows from operating activities are highly dependent on crude oil and natural gas prices, as well as petroleum and chemical product margins. In addition, to provide for cash flow in future periods, the company needs to continually find and develop new resources, and continue to develop and apply new technologies to existing fields in order to maintain or increase production.

The company s financial strength enables it to make large, long-term capital expenditures. Imperial s portfolio of development opportunities and the complementary nature of its business segments help mitigate the overall risks for the company and its cash flows. Further, due to its financial strength, debt capacity and portfolio of opportunities, the risk associated with 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.

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 completed at least once every three years, or more, depending on funding status. The most recent valuation of the company s registered retirement plans was completed as at December 31, 2013. As a result of the valuation, the company contributed $163 million to the registered retirement plans in 2016. Future funding requirements are not expected to affect the company s existing capital investment plans or its ability to pursue new investment opportunities.

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Cash flow from operating activities

2016

Cash flow generated from operating activities was $2,015 million in 2016, compared with $2,167 million in 2015, reflecting lower earnings, excluding the gain on retail sites and the general aviation business.

2015

Cash flow generated from operating activities was $2,167 million, compared with $4,405 million in 2014. Lower cash flow was due to lower earnings.

Cash flow from investing activities

2016

Investing activities generated net cash of $1,947 million in 2016, compared with cash used in investing activities of $2,884 million in 2015, reflecting proceeds from asset sales and the completion of major upstream growth projects.

2015

Cash used in investing activities of $2,884 million, compared with $4,562 million in 2014, mainly reflecting the decline in additions to property, plant and equipment.

Cash flow from financing activities

2016

Cash used in financing activities was $3,774 million in 2016, compared with cash provided by financing activities of $705 million in 2015. Cash from operating activities and proceeds from the asset sales were used to reduce outstanding debt.

At the end of 2016, total debt outstanding was $5,234 million, compared with $8,516 million at the end of 2015.

The company repaid debt of $1,505 million from existing long-term loan facilities and $1,749 million from short-term loan facilities.

In October 2016, the company decreased the amount of its unused committed long-term line of credit from $500 million to $250 million and extended the maturity date to November 2018.

In December 2016, the company decreased the amount of its unused committed short-term line of credit from $500 million to $250 million and extended the maturity date to December 2017.

During 2016, the company did not make any share repurchases except those to offset the dilutive effects from the exercise of share-based awards. The company will continue to evaluate its share repurchase program in the context of its operating performance and overall capital project activities.

Dividends paid in 2016 were $492 million. The per-share dividend paid was $0.58, up from $0.53 in 2015.

2015

Cash provided by financing activities was $705 million, compared with $100 million in 2014.

The company drew on existing loan facilities of $1,206 million.

At the end of 2015, total debt outstanding was $8,516 million, compared with $6,891 million at the end of 2014.

In March 2015, the company extended the maturity date of its existing $500 million 364-day short-term unsecured committed bank credit facility to March 2016. The company did not draw on the facility.

In July 2015, the company increased the capacity of its existing floating rate loan facility with an affiliated company of ExxonMobil from $6.25 billion to $7.75 billion. All terms and conditions of the agreement remained unchanged.

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In August 2015, the company extended the maturity date of its existing $500 million long-term bank credit facility to August 2017. The company did not draw on the facility.

Cash dividends of $449 million were paid in 2015 compared with $441 million in 2014. Per-share dividends paid in 2015 totalled $0.53, up from $0.52 in 2014.

Subsequent to December 31, 2015 and up to February 10, 2016, the company increased its total debt by $328 million by drawing on an existing facility. The increased debt was used to supplement normal operations and capital projects.

Financial percentages and ratios

	2016	2015	2014
Total debt as a percentage of capital (a)	**17**	27	23
Interest coverage ratio earnings basis (b)	**21**	20	61

(a) Current and long-term debt (page 55) and the company s share of equity company debt, divided by debt and shareholders equity (page 55).
(b) Net income (page 53), debt-related interest before capitalization, including the company s share of equity company interest, and income taxes (page 53), divided by debt-related interest before capitalization, including the company s share of equity company interest.

Debt represented 17 percent of the company s capital structure at the end of 2016.

Debt-related interest incurred in 2016, before capitalization of interest, was $121 million, compared with $102 million in 2015. The average effective interest rate on the company s debt was 1.5 percent in 2016, compared with 1.3 percent in 2015.

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

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

Commitments

The following table shows the company s commitments outstanding at December 31, 2016. It combines data from the consolidated balance sheet and from individual notes to the consolidated financial statements, where appropriate.

		Payment due by period	
millions of Canadian dollars	2017		Total

	Note reference		2018 to 2019	2020 to 2021	2022 and beyond	
Long-term debt (a)	14	-	54	4,478	500	5,032
- Due in one year		27				27
Operating leases (b)	13	139	129	4	3	275
Firm capital commitments (c)		48	31	71	-	150
Pension and other post-retirement obligations (d)	4	277	125	131	1,170	1,703
Asset retirement obligations (e)	5	55	218	184	1,015	1,472
Other long-term purchase agreements (f)		844	1,467	1,233	4,716	8,260

(a) Long-term debt includes a long-term loan from an affiliated company of ExxonMobil of $4,447 million and capital lease obligations of $612 million, $27 million of which is due in one year. The payment by period for the related party long-term loan is estimated based on the right of the related party to cancel the loan on at least 370 days advance written notice.

(b) Minimum commitments for operating leases, shown on an undiscounted basis, covers primarily storage tanks, rail cars and marine vessels.

(c) Firm capital commitments represent legally-binding payment obligations to third parties where agreements specifying all significant terms have been executed for the construction and purchase of fixed assets and other permanent investments. In certain cases where the company executes contracts requiring commitments to a work scope, those commitments have been included to the extent that the amounts and timing of payments can be reliably estimated. Firm capital commitments related to capital projects, shown on an undiscounted basis.

(d) 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 2017 and estimated benefit payments for unfunded plans in all years.

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(e) Asset retirement obligations represent the fair value of legal obligations associated with site restoration on the retirement of assets with determinable useful lives.
(f) Other long-term purchase agreements are non-cancelable, or cancelable only under certain conditions and long-term commitments other than unconditional purchase obligations. They include primarily raw material supply and transportation services agreements. The lower 2016 balance reflects a reduction of transportation service agreements totalling $2.7 billion. In addition, about $636 million of unconditional purchase obligation that existed at year-end 2015 no longer met the conditions for classification as unconditional purchase obligations and are now reported as other long-term purchase agreements.

Unrecognized tax benefits totaling $106 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 3 to the financial statements on page 65.

Litigation and other contingencies

As discussed in note 9 to the consolidated financial statements on page 74, a variety of claims have been made against Imperial and its subsidiaries. Based on a consideration of all relevant facts and circumstances, the company does not believe the ultimate outcome of any currently pending lawsuits against the company will have a material adverse effect on the company s operations, financial condition, or financial statements taken as a whole.

Additionally, as discussed in note 9, Imperial was contingently liable at December 31, 2016, for guarantees relating to performance under contracts of other third-party obligations. These guarantees do not have a material effect on the company s operations, financial condition, or financial statements taken as a whole.

There are no events or uncertainties beyond those already included in reported financial information that would indicate a material change in future operating results or financial condition.

Capital and exploration expenditures

millions of Canadian dollars	**2016**	2015
Upstream (a)	**896**	3,135
Downstream	**190**	340
Chemical	**26**	52
Other	**49**	68
Total	**1,161**	3,595

(a) Exploration expenses included.

Total capital and exploration expenditures were $1,161 million in 2016, a decrease of $2,434 million from 2015.

For the Upstream segment, capital expenditures were $896 million, compared with $3,135 million in 2015. Investments were primarily in support of completion of upstream projects.

Planned capital and exploration expenditures in the Upstream segment are forecast at about $600 million for 2017. Investments are mainly planned for sustaining activity.

For the Downstream segment, capital expenditures were $190 million in 2016, compared with $340 million in 2015. In 2016, investments were primarily in support of downstream sustaining activity.

Planned capital expenditures for the Downstream segment in 2017 are $350 million and focus on improving the reliability and efficiency of Imperial s operations, as well as enhancing the company s environmental and safety performance.

Total capital and exploration expenditures for the company in 2017 are expected to be about $1 billion. Actual spending could vary depending on the progress of individual projects.

Market risks and other uncertainties

Crude oil, natural gas, petroleum product and chemical prices have fluctuated in response to changing market forces. The impacts of these price fluctuations on earnings from Upstream, Downstream and Chemical operations have varied. Industry crude oil and natural gas commodity prices and petroleum and chemical

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product prices are commonly benchmarked in U.S. dollars. The majority of Imperial s sales and purchases are related to these industry U.S. dollar benchmarks. As the company records and reports its financial results in Canadian dollars, to the extent that the Canadian / U.S. dollar exchange rate fluctuates, the company s earnings will be affected. The company s potential exposure to commodity price and margin, and Canadian / U.S. dollar exchange rate fluctuations is summarized in the earnings sensitivities table below, which shows the estimated annual effect, under current conditions, on the company s after-tax net income.

In the competitive downstream and chemical environments, earnings are primarily determined by margin capture rather than absolute price levels on products sold. Refining margins are a function of the difference between what a refiner pays for its raw materials (primarily crude oil) and the market prices for the range of products produced. These prices in turn depend on global and regional supply / demand balances, inventory levels, refinery operations, import / export balances and weather.

Imperial is exposed to changes in interest rates, primarily on its debt which carries floating interest rates. The impact of a quarter percent change in interest rates affecting Imperial s debt would not be material to earnings, cash flow or fair value. Imperial has access to significant capacity of long-term and short-term liquidity. Internally generated funds are expected to cover the majority of financial requirements, supplemented by long-term and short-term debt as needed.

At this time Imperial is a net consumer of natural gas. It is used in Imperial s Upstream operations and refineries. A decrease in the value of natural gas reduces Imperial s operating expenses, thereby increasing Imperial s earnings.

Earnings sensitivities (a)

millions of Canadian dollars, after tax		
One dollar (U.S.) per barrel change in crude oil prices (b)	+ (-)	**100**
Ten cents per thousand cubic feet decrease (increase) in natural gas prices	+ (-)	**5**
One dollar (U.S.) per barrel change in refining 2-1-1 margins (c)	+ (-)	**140**
One cent (U.S.) per pound change in sales margins for polyethylene	+ (-)	**8**
One cent decrease (increase) in the value of the Canadian dollar versus the U.S. dollar	+ (-)	**85**

(a) Each sensitivity calculation shows the impact on net income resulting from a change in one factor, after tax and royalties and holding all other factors constant. These sensitivities have been updated to reflect current conditions. They may not apply proportionately to larger fluctuations.
(b) Impact on Upstream earnings only, after tax and royalties.
(c) The 2-1-1 crack spread is an indicator of the refining margin generated by converting two barrels of crude oil into one barrel of gasoline and one barrel of diesel.

The sensitivity of net income to changes in the Canadian dollar versus the U.S. dollar increased from 2015 year-end by about $10 million (after tax) a year for each one-cent change. The increase was primarily the result of higher production volumes.

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

In general, segment results are not dependent on the ability to sell and / or purchase products to / from other segments. Instead, where such sales take place, they are the result of efficiencies and competitive advantages of integrated refinery / chemical complexes. Additionally, intersegment sales are at market-based prices. The products bought and sold between segments can also be acquired in worldwide markets that have substantial liquidity, capacity and transportation capabilities. About 65 percent of the company s intersegment sales are crude oil produced by the Upstream and sold to the Downstream. Other intersegment sales include those between refineries and the chemical plant related to raw materials, feedstocks and finished products.

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

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Industry bitumen production may be subject to limits on transportation capacity to markets. A significant portion of the company s upstream production is bitumen. To mitigate uncertainty associated with the timing of industry pipeline projects and pipeline capacity constraints, the company has developed rail infrastructure.

The demand for crude oil, natural gas, petroleum products and petrochemical products correlates closely with general economic growth rates. The occurrence of recessions or other periods of low or negative economic growth will typically have a direct adverse impact on the company s financial results. In challenging economic times, the company follows the proven approach to continue to focus on the business elements within its control and take a long-term view. Technology improvements have played and will continue to play an important role in the economics and the environmental performance of current operations and future developments.

Risk management

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

Critical accounting estimates

The company s financial statements have been prepared in accordance with United States Generally Accepted Accounting Principles (GAAP). GAAP requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. 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 company s significant accounting policies are summarized in note 1 to the consolidated financial statements on page 58.

Oil and gas reserves

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

The estimation of proved reserves, which is based on the requirement of reasonable certainty, is an ongoing process based on rigorous technical evaluations, commercial and market assessments and detailed analysis of well information such as flow rates and reservoir pressure declines. 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 the reserves management group which has significant technical experience, culminating in reviews with and approval by senior management and the company s board of directors. Notably, the company does not use specific quantitative reserve targets to determine compensation. Key features of the reserve estimation process are covered in Disclosure of reserves in Item 1.

Oil and natural gas reserves include both proved and unproved reserves.

Proved oil and natural gas reserves are determined in accordance with Securities and Exchange Commission requirements. Proved reserves are those quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible under existing economic and operating conditions and government regulations. Proved reserves are determined using the average of first-of-month oil and natural gas prices during the reporting year.

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Proved reserves can be further subdivided into developed and undeveloped reserves. Proved developed reserves include amounts which are expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves include amounts expected to be recovered from new wells on undrilled proved acreage or from existing wells where a relatively major expenditure is required for completion. Proved undeveloped reserves are recognized only if a development plan has been adopted indicating that the reserves are scheduled to be drilled within five years, unless specific circumstances support a longer period of time.

The percentage of proved developed reserves was 77 percent of total proved reserves at year-end 2016, a reduction from 88 percent in 2015. 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 natural gas prices.

Unproved reserves are quantities of oil and natural gas with less than reasonable certainty of recoverability and include probable reserves. Probable reserves are reserves that, together with proved reserves, are as likely as not to be recovered.

Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the evaluation or re-evaluation of already available geologic, reservoir or production data; new geologic, reservoir or production data; or changes in the average of first-of-the-month prices and year-end costs that are used in the estimation of reserves. Revisions can also result from significant changes in either development strategy or production equipment / facility capacity.

As a result of low prices during 2016, under the U.S. Securities and Exchange Commission definition of proved reserves, certain quantities of bitumen that qualified as proved reserves in prior years did not qualify as proved reserves at year-end 2016. Amounts no longer qualifying as proved reserves include the entire 2.5 billion barrels of bitumen at Kearl and approximately 0.2 billion barrels of bitumen at Cold Lake. Among the factors that would result in these amounts being recognized again as proved reserves at some point in the future are a recovery in average price levels, a further decline in costs, and / or operating efficiencies. Under the terms of certain contractual arrangements or government royalty regimes, lower prices can also increase proved reserves attributable to Imperial. The company does not expect the downward revision of reported proved reserves under the U.S. Securities and Exchange Commission definitions to affect the operation of the underlying projects or to alter its outlook for future production volumes.

Unit-of-production depreciation

The calculation of unit-of-production depreciation is a critical accounting estimate that measures the depreciation of upstream assets. Oil and natural gas reserve quantities are used as the basis to calculate unit-of-production depreciation rates for most upstream assets. Depreciation is calculated by taking the ratio of asset cost to total proved reserves or proved developed reserves applied to the actual cost of production. The volumes produced and asset cost are known, while proved reserves are based on estimates that are subject to some variability.

In the event that the unit-of-production method does not result in an equitable allocation of cost over the economic life of an upstream asset, an alternative method is used. The straight-line method is used in limited situations where the expected life of the asset does not reasonably correlate with that of the underlying reserves. For example, certain assets used in the production of oil and natural gas have a shorter life than the reserves, and as such, the company uses straight-line depreciation to ensure the asset is fully depreciated by the end of its useful life.

To the extent that proved reserves for a property are entirely de-booked and that property continues to produce, assets will be depreciated using a unit-of-production method based on reserves determined at the most recent SEC price which results in a quantity of proved reserves greater than zero, appropriately adjusted for production and technical changes. The effect of this approach on the company s 2017 depreciation expense versus 2016 is anticipated to be immaterial.

Impact of oil and gas reserves and prices and margins on testing for impairment

The company tests assets or groups of assets for recoverability whenever events or circumstances indicate that the carrying amounts may not be recoverable.

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Among the events or changes in circumstances which could indicate that the carrying value of an asset or asset group may not be recoverable are the following:

- A significant decrease in the market price of a long-lived asset;
- A significant adverse change in the extent or manner in which an asset is being used or in its physical condition including a significant decrease in the company s current and projected reserve volumes;
- A significant adverse change in legal factors or in the business climate that could affect the value, including a significant adverse action or assessment by a regulator;
- An accumulation of project costs significantly in excess of the amount originally expected;
- A current-period operating loss combined with a history and forecast of operating or cash flow losses; and
- A current expectation that, more likely than not, a long-lived asset will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

The company performs asset valuation analyses on an ongoing basis as a part of its asset management program. These analyses and other profitability reviews assist the company in assessing whether the carrying amounts of any of its assets may not be recoverable.

In general, Imperial does not view temporarily low prices or margins as an indication of impairment. Management does not believe that lower prices are sustainable if energy is to be delivered with supply security to meet global demand over the long term. Although prices will occasionally drop significantly, industry prices over the long term will continue to be driven by market supply and demand. On the supply side, industry production from mature fields is declining, but this is being offset by production from new discoveries and field developments. OPEC production policies also have an impact on world oil supplies. The demand side is largely a function of global economic growth. Because the lifespans of the company s major assets are measured in decades, the value of these assets is predominantly based on long-term views of future commodity prices and production costs. During the lifespan of these major assets, the company expects that oil and gas prices will experience significant volatility, and consequently these assets will experience periods of higher earnings and periods of lower earnings, or even losses. In assessing whether the events or changes in circumstances indicate the carrying value of an asset may not be recoverable, the company considers recent periods of operating losses in the context of its longer-term view of prices. While near-term prices are subject to wide fluctuations, longer term price views are more stable and meaningful for purposes of assessing future cash flows.

When the industry experiences a prolonged and deep reduction in commodity prices, the market supply and demand conditions may result in changes to the company s long-term price or margin assumptions it uses for its capital investment decisions. To the extent those changes result in a significant reduction in the mid-point of its long-term oil and natural gas price or margin ranges, the company may consider that situation, in conjunction with other events and changes in circumstances such as a history of operating losses, as an indicator of potential impairment for certain assets.

In the upstream, the standardized measure of discounted cash flows included in the Supplemental information on oil and gas exploration and production activities is required to use prices based on the average of first-of-month prices. These prices represent discrete points in time and could be higher or lower than the company s long-term price assumptions which are used for impairment assessments. The company believes the standardized measure does not provide a reliable estimate of the expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its oil and gas reserves and therefore does not consider it relevant in determining whether events or changes in circumstances indicate the need for an impairment assessment.

If events or circumstances indicate that the carrying value may not be recoverable, the company estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. In performing this assessment, 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. Cash flows used in recoverability assessments are based on the company s assumptions which are developed in the annual planning and budgeting process, and are consistent with the criteria management uses to evaluate investment opportunities. These evaluations make use of the company s assumption of future crude oil and natural gas commodity prices, refining and chemical margins, volumes, costs, and foreign currency exchange rates. Volumes are based on projected field and facility production profiles, throughput, or sales. Where unproved reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the evaluation.

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An asset group is impaired if its undiscounted cash flows are less than the asset group s carrying value. Impairments are measured by the amount by which the carrying value exceeds fair value. Fair value is based on market prices if an active market exists for the asset group or discounted cash flows using a discount rate commensurate with the risk. Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs would be recorded based on the estimated economic chance of success and the length of time that the company expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period.

Continued weakness in the upstream industry environment during 2016 led the company to perform an assessment of its major long-lived assets as part of Imperial s annual planning and budgeting process, similar to the exercise undertaken in late 2015. The assessment reflected long-term crude and natural gas prices which are consistent with the mid-point of the ranges that management uses to evaluate investment opportunities and which are in the range of long-term price forecasts published by third-party industry experts and government agencies. This assessment indicated that Imperial s major asset groups have future undiscounted cash flow estimates exceeding carrying values.

Supplemental information regarding oil and gas results of operations, capitalized costs and reserves is provided following the notes to consolidated financial statements.

Inventories

Crude oil, products and merchandise inventories are carried at the lower of current market value or cost (generally determined under the last-in, first-out method LIFO).

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 5.5 percent used in 2016 compares to actual returns of 5.5 percent and 7.7 percent achieved over the last 10- and 20-year periods respectively, ending December 31, 2016. 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 4 to the consolidated financial statements on page 66. 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 average remaining service life of employees. Employee benefit expense represented about 2 percent of total expenses in 2016.

Asset retirement obligations and other environmental liabilities

Legal obligations associated with site restoration on the retirement of assets with determinable useful lives are recognized when they are incurred, which is typically at the time the assets are installed. The obligations are initially measured at fair value and discounted to present value. Over time, the discounted asset retirement obligation amount will be accreted for the change in its present value, with this effect included in production and manufacturing expenses. As payments to settle the obligations occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 25 years, the discount rate will be adjusted only as appropriate to reflect long-term changes in market rates and outlook. For 2016, the obligations were discounted at 6 percent and the accretion expense was $97 million, before tax, which was significantly less than 1 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.

Suspended exploratory well costs

The company continues capitalization of exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and 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. The facts and circumstances that support continued capitalization of suspended wells at year-end are disclosed in note 15 to the consolidated financial statements on page 78.

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.

The benefits of uncertain tax positions that the company has taken or expects to take in its income tax returns are 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 or expected to be 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 3 to the consolidated financial statements on page 65.

Recently issued accounting standards

In May 2014, the Financial Accounting Standards Board (FASB) issued a new standard, *Revenue from Contracts with Customers.* The standard establishes a single revenue recognition model for all contracts with customers, eliminates industry specific requirements and expands disclosure requirements. The standard will be adopted beginning January 1, 2018. The company expects to adopt the standard using the modified retrospective method, under which prior years results are not restated, but supplemental information on the impact of the new standard is provided for in the 2018 results. Imperial continues to evaluate other areas of the standard. The impact from the standard is not expected to have a material effect on the company s financial statements.

In February 2016, the FASB issued a new standard, *Leases*. The standard requires all leases with an initial term greater than one year be recorded on the balance sheet as a lease asset and lease liability, with little change to the income and cash flow statements. The standard is required to be adopted beginning January 1, 2019, with early adoption permitted. Imperial is evaluating the standard and its effect on the company s financial statements and plans to adopt it in 2019.

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Management s report on internal control over financial reporting

Management, including the company s chief executive officer and principal accounting officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over the company s financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on criteria established in *Internal Control Integrated Framework (2013)* 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, 2016.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the company s internal control over financial reporting as of December 31, 2016, as stated in their report which is included herein.

/s/ Richard M. Kruger

R.M. Kruger

Chairman, president and

chief executive officer

/s/ Beverley A. Babcock

B.A. Babcock

Senior vice-president,

finance and administration, and controller

(Principal accounting officer and principal financial officer)

February 22, 2017

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Report of independent registered public accounting firm

To the Shareholders of Imperial Oil Limited

We have audited the accompanying consolidated balance sheet of Imperial Oil Limited as of December 31, 2016 and December 31, 2015 and the related consolidated statements of income, comprehensive income, shareholders equity and cash flows for each of the years in the three-year period ended December 31, 2016.

In addition, we audited Imperial Oil Limited s internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying management s report on internal control over financial reporting. Our responsibility is to express an opinion on these consolidated financial statements and the company s internal control over financial reporting based on our integrated audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Imperial Oil Limited as of December 31, 2016 and December 31, 2015 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, Imperial Oil Limited maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.

/s/ PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta, Canada

February 22, 2017

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Consolidated statement of income (U.S. GAAP)

millions of Canadian dollars For the years ended December 31	**2016**	2015	2014
Revenues and other income			
Operating revenues (a) (b)	**25,049**	26,756	36,231
Investment and other income (note 8)	**2,305**	132	735
Total revenues and other income	**27,354**	26,888	36,966
Expenses			
Exploration (note 15)	**94**	73	67
Purchases of crude oil and products (c)	**15,120**	15,284	22,479
Production and manufacturing (d)	**5,224**	5,434	5,662
Selling and general (d)	**1,129**	1,117	1,075
Federal excise tax (a)	**1,650**	1,568	1,562
Depreciation and depletion	**1,628**	1,450	1,096
Financing costs (note 12)	**65**	39	4
Total expenses	**24,910**	24,965	31,945
Income (loss) before income taxes	**2,444**	1,923	5,021
Income taxes (note 3)	**279**	801	1,236
Net income (loss)	**2,165**	1,122	3,785
Per-share information (Canadian dollars)			
Net income (loss) per common share - basic (note 10)	**2.55**	1.32	4.47
Net income (loss) per common share - diluted (note 10)	**2.55**	1.32	4.45
Dividends per common share	**0.59**	0.54	0.52
(a) Federal excise tax included in operating revenues.	**1,650**	1,568	1,562
(b) Amounts from related parties included in operating revenues (note 16).*	**2,342**	3,058	3,358
(c) Amounts to related parties included in purchases of crude oil and products (note 16).*	**2,224**	2,684	3,262
(d) Amounts to related parties included in production and manufacturing, and selling and general expenses (note 16).	**533**	442	366

*Note: Restated 2015 and 2014.

The information in the notes to consolidated financial statements is an integral part of these statements.

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Consolidated statement of comprehensive income (U.S. GAAP)

millions of Canadian dollars For the years ended December 31	**2016**	2015	2014
Net income (loss)	**2,165**	1,122	3,785
Other comprehensive income (loss), net of income taxes			
Post-retirement benefits liability adjustment (excluding amortization)	**(210)**	64	(483)
Amortization of post-retirement benefits liability adjustment included in net periodic benefit costs	**141**	167	145
Total other comprehensive income (loss)	**(69)**	231	(338)
Comprehensive income (loss)	**2,096**	1,353	3,447

The information in the notes to consolidated financial statements is an integral part of these statements.

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Consolidated balance sheet (U.S. GAAP)

millions of Canadian dollars At December 31	**2016**	2015
Assets		
Current assets		
Cash	**391**	203
Accounts receivable, less estimated doubtful accounts (a)	**2,023**	1,581
Inventories of crude oil and products (note 11)	**949**	1,190
Materials, supplies and prepaid expenses	**468**	424
Deferred income tax assets (b) (note 3)	**-**	272
Total current assets	**3,831**	3,670
Investments and long-term receivables	**1,030**	1,254
Property, plant and equipment, less accumulated depreciation and depletion (note 2)	**36,333**	37,799
Goodwill	**186**	224
Other assets, including intangibles, net (b)	**274**	223
Total assets (note 2)	**41,654**	43,170
Liabilities		
Current liabilities		
Notes and loans payable (c) (note 12)	**202**	1,952
Accounts payable and accrued liabilities (a) (b) (note 11)	**3,193**	2,989
Income taxes payable	**488**	452
Total current liabilities	**3,883**	5,393
Long-term debt (d) (note 14)	**5,032**	6,564
Other long-term obligations (e) (note 5)	**3,656**	3,597
Deferred income tax liabilities (b) (note 3)	**4,062**	4,191
Total liabilities	**16,633**	19,745
Commitments and contingent liabilities (note 9)		
Shareholders equity		
Common shares at stated value (f) (note 10)	**1,566**	1,566
Earnings reinvested	**25,352**	23,687
Accumulated other comprehensive income (loss) (note 17)	**(1,897)**	(1,828)
Total shareholders equity	**25,021**	23,425

Total liabilities and shareholders equity	**41,654**	43,170

(a) Accounts receivable, less estimated doubtful accounts included net amounts receivable from related parties of $172 million (2015 - $129 million), (note 16).
(b) Per ASU 2015-17, deferred tax assets and liabilities have been prospectively classified as non-current. Prior periods were not restated (note 1).
(c) Notes and loans payable included amounts to related parties of $75 million (2015 $75 million), (note 16).
(d) Long-term debt included amounts to related parties of $4,447 million (2015 $5,952 million), (note 16).
(e) Other long-term obligations included amounts to related parties of $104 million (2015 $146 million), (note 16).
(f) Number of common shares authorized and outstanding were 1,100 million and 848 million, respectively (2015 1,100 million and 848 million, respectively), (note 10).

The information in the notes to consolidated financial statements is an integral part of these statements.

Approved by the directors

/s/ Richard M. Kruger	*/s/ Beverley A. Babcock*
R.M. Kruger	B.A. Babcock
Chairman, president and	Senior vice-president,
chief executive officer	finance and administration, and controller

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

millions of Canadian dollars At December 31	**2016**	2015	2014
Common shares at stated value (note 10)			
At beginning of year	**1,566**	1,566	1,566
Issued under the stock option plan	**-**	-	-
Share purchases at stated value	**-**	-	-
At end of year	**1,566**	1,566	1,566
Earnings reinvested			
At beginning of year	**23,687**	23,023	19,679
Net income (loss) for the year	**2,165**	1,122	3,785
Share purchases in excess of stated value	**-**	-	-
Dividends declared	**(500)**	(458)	(441)
At end of year	**25,352**	23,687	23,023
Accumulated other comprehensive income (loss) (note 17)			
At beginning of year	**(1,828)**	(2,059)	(1,721)
Other comprehensive income (loss)	**(69)**	231	(338)
At end of year	**(1,897)**	(1,828)	(2,059)
Shareholders equity at end of year	**25,021**	23,425	22,530

The information in the notes to consolidated financial statements is an integral part of these statements.

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

millions of Canadian dollars Inflow (outflow) For the years ended December 31	**2016**	2015	2014
Operating activities			
Net income (loss)	**2,165**	1,122	3,785
Adjustments for non-cash items:			
Depreciation and depletion	**1,628**	1,450	1,096
(Gain) loss on asset sales (note 8)	**(2,244)**	(97)	(696)
Inventory write-down to current market value (note 11)	**-**	59	-
Deferred income taxes and other	**114**	367	1,123
Changes in operating assets and liabilities:			
Accounts receivable	**(442)**	(42)	545
Inventories, materials, supplies and prepaid expenses	**197**	(172)	(129)
Income taxes payable	**36**	418	(693)
Accounts payable and accrued liabilities	**237**	(1,030)	(549)
All other items - net (a)	**324**	92	(77)
Cash flows from (used in) operating activities	**2,015**	2,167	4,405
Investing activities			
Additions to property, plant and equipment	**(1,073)**	(2,994)	(5,290)
Proceeds from asset sales (note 8)	**3,021**	142	851
Additional investments	**(1)**	(32)	(123)
Cash flows from (used in) investing activities	**1,947**	(2,884)	(4,562)
Financing activities			
Short-term debt - net	**(1,749)**	(32)	120
Long-term debt - additions (note 14)	**495**	1,206	430
Long-term debt - reductions (note 14)	**(2,000)**	-	-
Reduction in capitalized lease obligations	**(28)**	(20)	(9)
Dividends paid	**(492)**	(449)	(441)
Cash flows from (used in) financing activities	**(3,774)**	705	100
Increase (decrease) in cash	**188**	(12)	(57)
Cash at beginning of year	**203**	215	272
Cash at end of year (b)	**391**	203	215

(a) Included contribution to registered pension plans.	**163**	225	362

(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.

Non-cash transactions

In 2015, a capital lease of approximately $480 million was not included in Additions to property, plant and equipment or Long-term debt issued lines on the Consolidated statement of cash flows.

The information in the notes to consolidated financial statements is an integral part of these statements.

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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 United States Generally Accepted Accounting Principles. GAAP requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates. Prior years data has been reclassified in certain cases to conform to the 2016 presentation basis. 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 subsidiaries the company controls. 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 Ventures Limited and McColl-Frontenac Petroleum ULC. All of the above companies are wholly owned. The consolidated financial statements also include the company s share of the undivided interest in certain upstream assets, liabilities, revenues and expenses, including its 25 percent interest in the Syncrude joint venture and its 70.96 percent interest in the Kearl joint venture.

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 company s interests in the underlying net assets of affiliates it does not control, but over which it exercises significant influence, 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 investments 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 and a rail loading joint venture that facilitate the sale and purchase of liquids in the conduct of company operations. Other parties who also have an equity interest in these investments share in the risks and rewards according to their percentage of ownership. Imperial does not invest in these investments in order to remove liabilities from its balance sheet.

Property, plant and equipment

Cost basis

Imperial 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. Costs incurred to purchase, lease, or otherwise acquire a property (whether unproved or proved) are capitalized when incurred. Exploratory well costs are carried as an asset when the well has found a sufficient quantity of reserves to justify its completion as a producing well and where the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs that do not meet the criteria are charged to expense. Other exploratory expenditures, including geophysical costs and annual lease rentals, are expensed as incurred. Development costs, including costs of productive wells and development dryholes, are capitalized.

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.

Depreciation, depletion and amortization

Depreciation, depletion and amortization are primarily determined under either the unit-of-production method or the straight-line method, which is based on estimated asset service life taking obsolescence into consideration. 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. Capitalized exploratory drilling and development costs associated with productive depletable extractive properties are amortized using the unit-of-production rates based on the amount of proved developed reserves of oil and gas that are estimated to be recoverable from existing facilities using current operating methods. Under the unit-of-production method, oil and gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the lease or field storage tank. In the event that the unit-of-production method does not result in an equitable allocation of cost over the economic life of an upstream asset, an alternative method is used. The straight-line method is used in limited situations where the expected life of the asset does not reasonably correlate with that of the underlying reserves. For example, certain assets used in the production of oil and natural gas have a shorter life than the reserves, and as such, the company uses straight-line depreciation to ensure the asset is fully depreciated by the end of its useful life. Investments in mining heavy equipment and certain ore processing plant assets at oil sands mining properties are depreciated on a straight-line basis over a maximum of 15 years and 50 years respectively. Depreciation of other plant and equipment is calculated using the straight-line method, based on the estimated service life of the asset.

Under the SEC definition of proved reserves, certain quantities of bitumen no longer qualified as proved reserves at year-end 2016, the substantial majority of which relates to the Kearl oil sands operation, where no proved reserves remain. To the extent that proved reserves for a property are entirely de-booked and that property continues to produce, assets will be depreciated using a unit-of-production method based on reserves determined at the most recent SEC price which results in a quantity of proved reserves greater than zero, appropriately adjusted for production and technical changes.

Investments in refinery, chemical process, and lubes basestock manufacturing equipment are generally depreciated on a straight-line basis over a 25-year life. Maintenance and repairs, including planned major maintenance, are expensed as incurred. Major renewals and improvements are capitalized and the assets replaced are retired.

Impairment assessment

The company tests assets or groups of assets for recoverability whenever events or circumstances indicate that the carrying amounts may not be recoverable.

Among the events or changes in circumstances which could indicate that the carrying value of an asset or asset group may not be recoverable are the following:

A significant decrease in the market price of a long-lived asset;
A significant adverse change in the extent or manner in which an asset is being used or in its physical condition including a significant decrease in the company s current and projected reserve volumes;
A significant adverse change in legal factors or in the business climate that could affect the value, including a significant adverse action or assessment by a regulator;
An accumulation of project costs significantly in excess of the amount originally expected;
A current-period operating loss combined with a history and forecast of operating or cash flow losses; and
A current expectation that, more likely than not, a long-lived asset will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

The company performs asset valuation analyses on an ongoing basis as a part of its asset management program. These analyses and other profitability reviews assist the company in assessing whether the carrying amounts of any of its assets may not be recoverable.

In general, Imperial does not view temporarily low prices or margins as an indication of impairment. Management does not believe that lower prices are sustainable if energy is to be delivered with supply security to meet global demand over the long term. Although prices will occasionally drop significantly, industry prices over the long term will continue to be driven by market supply and demand. On the supply side, industry production from mature fields is declining, but this is being offset by production from new discoveries and field developments. OPEC production policies also have an impact on world oil supplies. The demand side is largely a function of global economic growth. Because the lifespans of the company s major assets are measured in decades, the value of these assets is predominantly based on long-term views of future commodity prices and production costs. During the lifespan of these major assets, the company expects that oil and gas prices will experience significant volatility, and consequently these assets will experience periods of higher earnings and periods of lower earnings, or even losses. In assessing whether the events or changes in circumstances indicate the carrying value of an asset may not be recoverable, the company considers recent periods of operating losses in the context of its longer-term view of prices. While near-term prices are subject to wide fluctuations, longer term price views are more stable and meaningful for purposes of assessing future cash flows.

When the industry experiences a prolonged and deep reduction in commodity prices, the market supply and demand conditions may result in changes to the company s long-term price or margin assumptions it uses for its capital investment decisions. To the extent those changes result in a significant reduction in the mid-point of its long-term oil and natural gas price or margin ranges, the company may consider that situation, in conjunction with other events and changes in circumstances such as a history of operating losses, as an indicator of potential impairment for certain assets.

In the upstream, the standardized measure of discounted cash flows included in the Supplemental information on oil and gas exploration and production activities is required to use prices based on the average of first-of-month prices. These prices represent discrete points in time and could be higher or lower than the company s long-term price assumptions which are used for impairment assessments. The company believes the standardized measure does not provide a reliable estimate of the expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its oil and gas reserves and therefore does not consider it relevant in determining whether events or changes in circumstances indicate the need for an impairment assessment.

If events or circumstances indicate that the carrying value may not be recoverable, the company estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. In performing this assessment, 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. Cash flows used in recoverability assessments are based on the company s assumptions which are developed in the annual planning and budgeting process, and are consistent with the criteria management uses to evaluate investment opportunities. These evaluations make use of the company s assumption of future crude oil and natural gas commodity prices, refining and chemical margins, volumes, costs, and foreign currency exchange rates. Volumes are based on projected field and facility production profiles, throughput, or sales. Where unproved reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the evaluation.

An asset group is impaired if its undiscounted cash flows are less than the asset group s carrying value. Impairments are measured by the amount by which the carrying value exceeds fair value. Fair value is based on market prices if an active market exists for the asset group or discounted cash flows using a discount rate commensurate with the risk.

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs would be recorded based on the estimated economic chance of success and the length of time that the company expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period.

Gains on sales of proved and unproved properties are only recognized when there is neither uncertainty about the recovery of costs applicable to any interest retained nor any substantial obligation for future performance by the company.

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Losses on properties sold are recognized when incurred or when the properties are held for sale and the fair value of the properties is less than the carrying value.

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

Interest capitalization

Interest costs incurred to finance expenditures during the construction phase of multiyear projects are capitalized as part of property, plant and equipment and are depreciated over the service life of the related assets. The project construction phase commences with the development of the detailed engineering design and ends when the constructed assets are ready for their intended use.

Goodwill and other intangible assets

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

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

Asset retirement obligations and other environmental liabilities

Legal obligations associated with site restoration on the retirement of assets with determinable useful lives are recognized when they are incurred, which is typically at the time the assets are installed. These obligations primarily relate to soil reclamation and remediation and costs of abandonment and demolition of oil and gas wells and related facilities. The company uses estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation, technical assessments of the assets, estimated amounts and timing of settlements, the credit-adjusted risk-free rate to be used, and inflation rates. The obligations are initially measured at fair value and discounted to present value. A corresponding amount equal to that of the initial obligation is added to the capitalized costs of the related asset. Over time, the discounted asset retirement obligation amount will be accreted for the change in its present value, and the initial capitalized costs will be depreciated over the useful lives of the related assets.

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

Foreign-currency translation

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

Fair value

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

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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 collectability 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 certain employees in the form of restricted stock units. Compensation expense is measured each reporting period based on the company s current stock price and is recorded as selling and general expenses in the consolidated statement of income over the requisite service period of each award. See note 7 to the consolidated financial statements on page 72 for further details.

Consumer taxes

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

Recently issued accounting standards

In May 2014, the Financial Accounting Standards Board (FASB) issued a new standard, *Revenue from Contracts with Customers.* The standard establishes a single revenue recognition model for all contracts with customers, eliminates industry specific requirements and expands disclosure requirements. The standard will be adopted beginning January 1, 2018. The company expects to adopt the standard using the modified retrospective method, under which prior years results are not restated, but supplemental information on the impact of the new standard is provided for in the 2018 results. Imperial continues to evaluate other areas of the standard. The impact from the standard is not expected to have a material effect on the company s financial statements.

In February 2016, the FASB issued a new standard, *Leases*. The standard requires all leases with an initial term greater than one year be recorded on the balance sheet as a lease asset and lease liability, with little change to the income and cash flow statements. The standard is required to be adopted beginning January 1, 2019, with early adoption permitted. Imperial is evaluating the standard and its effect on the company s financial statements and plans to adopt it in 2019.

Effective September 30, 2016, Imperial early adopted *Accounting Standards Update (ASU) no. 2015-17 Income Taxes (Topic 740)*: *Balance sheet classification of deferred taxes*, on a prospective basis. This update eliminates the requirement to classify deferred tax assets and liabilities as current and non-current, and instead requires all deferred tax assets and liabilities to be classified as non-current.

The balance sheet classification of deferred income tax assets / (liabilities) are shown below.

millions of Canadian dollars	**As at Dec 31 2016**	As at Dec 31 2015
Deferred income tax assets	**-**	272
Other assets, including intangibles, net	**57**	-
Accounts payable and accrued liabilities	**-**	(41)
Deferred income tax liabilities	**(4,062)**	(4,191)
Net deferred tax liabilities	**(4,005)**	(3,960)

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2. 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 to distribute and market these products. The Chemical segment is organized and operates to manufacture and market hydrocarbon-based chemicals and chemical products. The above segmentation has been the long-standing practice of the company and is broadly understood across the petroleum and petrochemical industries.

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

Corporate and Other includes assets and liabilities that do not specifically relate to business segments primarily cash, capitalized interest costs, short-term borrowings, long-term debt and liabilities associated with incentive compensation and post-retirement benefits liability adjustment. Net earnings effects in this segment primarily include debt-related 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 proportional segment expenses. 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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	Upstream			Downstream			Chemical		
millions of Canadian dollars	**2016**	2015	2014	**2016**	2015	2014	**2016**	2015	2014
Revenues and other income									
Operating revenues (a)	**5,492**	5,776	8,408	**18,511**	19,796	26,400	**1,046**	1,184	1,423
Intersegment sales	**2,215**	2,486	4,087	**1,007**	1,019	1,359	**212**	234	381
Investment and other income (note 8)	**13**	22	667	**2,278**	104	65	**-**	-	-
	7,720	8,284	13,162	**21,796**	20,919	27,824	**1,258**	1,418	1,804
Expenses									
Exploration (note 15)	**94**	73	67	**-**	-	-	**-**	-	-
Purchases of crude oil and products	**3,666**	3,768	5,628	**14,178**	14,526	21,476	**705**	725	1,196
Production and manufacturing	**3,591**	3,766	3,882	**1,428**	1,461	1,564	**205**	207	216
Selling and general	**(5)**	(2)	3	**972**	986	887	**83**	87	70
Federal excise tax	**-**	-	-	**1,650**	1,568	1,562	**-**	-	-
Depreciation and depletion	**1,396**	1,193	857	**206**	233	216	**10**	11	12
Financing costs (note 12)	**(7)**	5	4	**-**	-	-	**-**	-	-
Total expenses	**8,735**	8,803	10,441	**18,434**	18,774	25,705	**1,003**	1,030	1,494
Income (loss) before income taxes	**(1,015)**	(519)	2,721	**3,362**	2,145	2,119	**255**	388	310
Income taxes (note 3)									
Current	**(491)**	(77)	(219)	**674**	476	296	**68**	97	76
Deferred	**137**	262	881	**(66)**	83	229	**-**	4	5
Total income tax expense	**(354)**	185	662	**608**	559	525	**68**	101	81
Net income (loss)	**(661)**	(704)	2,059	**2,754**	1,586	1,594	**187**	287	229
Cash flows from (used in) operating activities	**402**	224	2,519	**1,574**	1,686	1,666	**203**	383	250
Capital and exploration expenditures (b)	**896**	3,135	4,974	**190**	340	572	**26**	52	26
Property, plant and equipment									
Cost	**45,850**	45,171	42,142	**6,166**	7,596	7,460	**872**	857	798
	(12,312)	(11,016)	(10,103)	**(4,037)**	(4,584)	(4,459)	**(629)**	(616)	(601)

Accumulated depreciation and depletion									
Net property, plant and equipment (c)	**33,538**	34,155	32,039	**2,129**	3,012	3,001	**243**	241	197
Total assets	**36,840**	36,971	34,421	**3,958**	5,574	5,823	**346**	394	372

	Corporate and Other			Eliminations			Consolidated		
millions of Canadian dollars	**2016**	2015	2014	**2016**	2015	2014	**2016**	2015	2014
Revenues and other income									
Operating revenues (a)	**-**	-	-	**-**	-	-	**25,049**	26,756	36,231
Intersegment sales	**-**	-	-	**(3,434)**	(3,739)	(5,827)	**-**	-	-
Investment and other income (note 8)	**14**	6	3	**-**	-	-	**2,305**	132	735
	14	6	3	**(3,434)**	(3,739)	(5,827)	**27,354**	26,888	36,966
Expenses									
Exploration (note 15)	**-**	-	-	**-**	-	-	**94**	73	67
Purchases of crude oil and products	**-**	-	-	**(3,429)**	(3,735)	(5,821)	**15,120**	15,284	22,479
Production and manufacturing	**-**	-	-	**-**	-	-	**5,224**	5,434	5,662
Selling and general	**84**	50	121	**(5)**	(4)	(6)	**1,129**	1,117	1,075
Federal excise tax	**-**	-	-	**-**	-	-	**1,650**	1,568	1,562
Depreciation and depletion	**16**	13	11	**-**	-	-	**1,628**	1,450	1,096
Financing costs (note 12)	**72**	34	-	**-**	-	-	**65**	39	4
Total expenses	**172**	97	132	**(3,434)**	(3,739)	(5,827)	**24,910**	24,965	31,945
Income (loss) before income taxes	**(158)**	(91)	(129)	**-**	-	-	**2,444**	1,923	5,021
Income taxes (note 3)									
Current	**(51)**	(45)	(47)	**-**	-	-	**200**	451	106
Deferred	**8**	1	15	**-**	-	-	**79**	350	1,130
Total income tax expense	**(43)**	(44)	(32)	**-**	-	-	**279**	801	1,236
Net income (loss)	**(115)**	(47)	(97)	**-**	-	-	**2,165**	1,122	3,785
Cash flows from (used in) operating activities	**(143)**	(124)	(30)	**(21)**	(2)	-	**2,015**	2,167	4,405
Capital and exploration	**49**	68	82	**-**	-	-	**1,161**	3,595	5,654

expenditures (b)									
Property, plant and equipment									
Cost	**627**	579	511	**-**	-	-	**53,515**	54,203	50,911
Accumulated depreciation and depletion	**(204)**	(188)	(174)	**-**	-	-	**(17,182)**	(16,404)	(15,337)
Net property, plant and equipment (c)	**423**	391	337	**-**	-	-	**36,333**	37,799	35,574
Total assets	**894**	579	565	**(384)**	(348)	(351)	**41,654**	43,170	40,830

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(a) Includes export sales to the United States of $3,612 million (2015 - $4,157 million, 2014 - $5,940 million). Export sales to the United States were recorded in all operating segments, with the largest effects in the Upstream segment.
(b) Capital and exploration expenditures (CAPEX) include exploration expenses, additions to property, plant and equipment, additions to capital leases, additional investments and acquisitions.
(c) Includes property, plant and equipment under construction of $2,705 million (2015 - $3,719 million).

3. Income taxes

millions of Canadian dollars	**2016**	2015	2014
Current income tax expense (a)	**200**	451	106
Deferred income tax expense (a) (b)	**79**	350	1,130
Total income tax expense (a) (c)	**279**	801	1,236
Statutory corporate tax rate (percent)	**26.8**	27.2	25.5
Increase (decrease) resulting from:			
Disposals (d)	**(11.6)**	(0.4)	(0.1)
Enacted tax rate change (a)	**-**	16.1	-
Other	**(3.8)**	(1.2)	(0.8)
Effective income tax rate	**11.4**	41.7	24.6

(a) On June 30, 2015 the Alberta government enacted a 2 percent increase in the provincial tax rate, from 10 percent to 12 percent.
(b) There were no material net (charges) credits for the effect of changes in tax laws and rates included in the provisions for deferred income taxes in 2014 and 2016.
(c) Cash outflow from income taxes, plus investment credits earned, was $172 million (2015 - $202 million, 2014 - $811 million).
(d) 2016 disposals are primarily associated with the sales of company-owned Esso retail sites and the general aviation business. Capital gains tax treatment was applied on the majority of disposals.

In 2016, the decrease in the statutory tax rate in the other category mainly represents prior year adjustments and re-assessments.

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

millions of Canadian dollars	**2016**	2015	2014
Depreciation and amortization	**5,361**	4,677	3,777
Successful drilling and land acquisitions	**891**	922	827
Pension and benefits	**(457)**	(396)	(438)
Asset retirement obligation	**(396)**	(406)	(304)
Capitalized interest	**114**	104	82
LIFO inventory valuation (a)	**(240)**	-	-
Tax loss carryforwards	**(1,056)**	(610)	(30)
Other (a)	**(212)**	(100)	(73)
Net long-term deferred income tax liabilities	**4,005**	4,191	3,841

LIFO inventory valuation (a)	**-**	(112)	(201)
Other (a)	**-**	(160)	(113)
Net current deferred income tax assets	**-**	(272)	(314)
Net current deferred income tax liabilities (a)	**-**	41	-
Net deferred income tax liabilities	**4,005**	3,960	3,527

(a) Per ASU 2015-17, deferred tax assets and liabilities have been prospectively classified as non-current. Prior periods were not restated (note 1).

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Unrecognized tax benefits

Unrecognized tax benefits reflect the difference between positions taken or expected to be taken on income tax returns and the amounts recognized in the financial statements.

The following table summarizes the movement in unrecognized tax benefits:

millions of Canadian dollars	**2016**	2015	2014
Balance as of January 1	**132**	151	151
Additions based on current year s tax position	**-**	-	4
Additions for prior years tax position	**2**	10	-
Reductions for prior years tax positions	**(23)**	(29)	(4)
Reductions due to lapse of the statute of limitations	**(5)**	-	-
Balance as of December 31	**106**	132	151

The unrecognized tax benefit balances shown above are predominately related to tax positions that would reduce the company s effective tax rate if the positions are favourably resolved. Unfavourable resolution of these tax positions generally would not increase the effective tax rate. The 2016, 2015 and 2014 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 2009 to 2016 are subject to examination by the tax authorities. Tax filing from 1994 to 1996, 1998 and 2000 to 2008 have open objections and therefore are also subject to examination by the tax authorities. The Canada Revenue Agency has proposed certain adjustments to the company s filings. Management is currently evaluating those proposed adjustments and believes that a number of outstanding matters are expected to be resolved in 2017. The impact on unrecognized tax benefits and the company s effective income tax rate from these matters is not expected to be material.

Resolution of the related tax positions will take many years to complete. It is difficult to predict the timing of resolution for tax positions since such timing is not entirely within the control of the company.

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

4. Employee retirement benefits

Retirement benefits, which cover almost all retired employees and their surviving spouses, include pension income and certain health care and life insurance benefits. They are met through funded registered retirement plans and through unfunded supplementary benefits that are paid directly to recipients.

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

The expense and obligations for both funded and unfunded benefits are determined in accordance with accepted actuarial practices and U.S. GAAP. 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	
	2016	2015	**2016**	2015
Assumptions used to determine benefit obligations at December 31 (percent)				
Discount rate	**3.75**	4.00	**3.75**	4.00
Long-term rate of compensation increase	**4.50**	4.50	**4.50**	4.50
millions of Canadian dollars				
Change in projected benefit obligation				
Projected benefit obligation at January 1	**8,147**	7,970	**642**	634
Current service cost	**203**	211	**16**	15
Interest cost	**319**	307	**27**	25
Actuarial loss (gain)	**157**	114	**46**	(2)
Benefits paid (a)	**(470)**	(455)	**(25)**	(30)
Projected benefit obligation at December 31	**8,356**	8,147	**706**	642
Accumulated benefit obligation at December 31	**7,681**	7,506		

The discount rate for calculating year-end post-retirement liabilities is based on the yield for high-quality, long-term Canadian corporate bonds at year-end with an average maturity (or duration) approximately that of the liabilities. The measurement of the accumulated post-retirement benefit obligation assumes a health care cost trend rate of 4.50 percent in 2017 and subsequent years.

	Pension benefits		Other post-retirement benefits	
millions of Canadian dollars	**2016**	2015	**2016**	2015
Change in plan assets				
Fair value at January 1	**7,260**	6,807		
Actual return (loss) on plan assets	**316**	592		
Company contributions	**163**	225		
Benefits paid (b)	**(380)**	(364)		
Fair value at December 31	**7,359**	7,260		
Plan assets in excess of (less than) projected benefit obligation at December 31				
Funded plans	**(444)**	(300)		
Unfunded plans	**(553)**	(587)	**(706)**	(642)
Total (c)	**(997)**	(887)	**(706)**	(642)

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

Funding of registered retirement plans complies with federal and provincial pension regulations, and the company makes contributions to the plans based on an independent actuarial valuation. In accordance with authoritative guidance relating to the accounting for defined pension and other post-retirement benefits plans, the underfunded status of the company s defined benefit post-retirement plans was recorded as a liability in the balance sheet, and the changes in that funded status in the year in which the changes occurred was recognized through other comprehensive income.

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millions of Canadian dollars	Pension benefits 2016	2015	Other post-retirement benefits 2016	2015
Amounts recorded in the consolidated balance sheet consist of:				
Current liabilities	**(29)**	(30)	**(29)**	(29)
Other long-term obligations	**(968)**	(857)	**(677)**	(613)
Total recorded	**(997)**	(887)	**(706)**	(642)
Amounts recorded in accumulated other comprehensive income consist of:				
Net actuarial loss (gain)	**2,461**	2,382	**197**	164
Prior service cost	**14**	23	**-**	-
Total recorded in accumulated other comprehensive income, before tax	**2,475**	2,405	**197**	164

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 percentages and the long-term return assumption for each asset class. The 2016 long-term expected return of 5.5 percent used in the calculations of pension expense compares to an actual rate of return of 5.5 percent and 7.7 percent over the last 10- and 20-year periods respectively, ending December 31, 2016.

millions of Canadian dollars	Pension benefits 2016	2015	2014	Other post-retirement benefits 2016	2015	2014
Assumptions used to determine net periodic benefit cost for years ended December 31 (percent)						
Discount rate	**4.00**	3.75	4.75	**4.00**	3.75	4.75
Long-term rate of return on funded assets	**5.50**	5.75	6.25	**-**	-	-
Long-term rate of compensation increase	**4.50**	4.50	4.50	**4.50**	4.50	4.50
millions of Canadian dollars						
Components of net periodic benefit cost						
Current service cost	**203**	211	152	**16**	15	9
Interest cost	**319**	307	322	**27**	25	26
Expected return on plan assets	**(400)**	(392)	(369)	**-**	-	-
Amortization of prior service cost	**9**	16	23	**-**	-	-
Amortization of actuarial loss (gain)	**162**	198	166	**13**	14	7
Net periodic benefit cost	**293**	340	294	**56**	54	42
Changes in amounts recorded in accumulated other comprehensive income						
Net actuarial loss (gain)	**241**	(86)	529	**46**	(2)	123
Amortization of net actuarial (loss) gain included in net periodic benefit cost	**(162)**	(198)	(166)	**(13)**	(14)	(7)

Amortization of prior service cost included in net periodic benefit cost	**(9)**	(16)	(23)	**-**	-	-
Total recorded in other comprehensive income	**70**	(300)	340	**33**	(16)	116
Total recorded in net periodic benefit cost and other comprehensive income, before tax	**363**	40	634	**89**	38	158

Costs for defined contribution plans, primarily the employee savings plan, were $44 million in 2016 (2015 - $43 million, 2014 - $40 million).

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

millions of Canadian dollars	Total pension and other post-retirement benefits 2016	2015	2014
(Charge) credit to other comprehensive income, before tax	**(103)**	316	(456)
Deferred income tax (charge) credit (note 17)	**34**	(85)	118
(Charge) credit to other comprehensive income, after tax	**(69)**	231	(338)

The company s investment strategy for pension plan assets reflects a long-term view, a careful assessment of the risks inherent in various asset classes and broad diversification to reduce the risk of the portfolio. Consistent with the long-term nature of the liability, the plan assets are primarily invested in global, market-cap-weighted indexed equity and domestic indexed bond funds to diversify risk while minimizing costs. The equity funds hold Imperial Oil Limited stock only to the extent necessary to replicate the relevant equity index. The balance of the plan assets is largely invested in high-quality corporate and government debt securities. Studies are periodically conducted to establish the preferred target asset allocation. The target asset allocation for equity securities is 37 percent. The target allocation for debt securities is 58 percent. Plan assets for the remaining 5 percent are invested in venture capital partnerships that pursue a strategy of investment in U.S. and international early stage ventures.

The 2016 fair value of the pension plan assets, including the level within the fair value hierarchy, is shown in the table below:

	Fair value measurements at December 31, 2016, using:				
millions of Canadian dollars	Total	Level 1	Level 2	Level 3	Net Asset Value (a)
Asset class					
Equity securities	-				-
Canadian	433				433
Non-Canadian	2,448				2,448
Debt securities - Canadian					
Corporate	988				988
Government	3,218				3,218
Asset backed	-				-
Equities Venture capital	241				241
Cash	31	6			25
Total plan assets at fair value	7,359	6	-	-	7,353

(a) Per ASU 2015-07, certain investments that are measured at fair value using the Net Asset Value (NAV) per share practical expedient have not been categorized in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the total value of plan assets.

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The 2015 fair value of the pension plan assets, including the level within the fair value hierarchy, is shown in the table below:

	Fair value measurements at December 31, 2015, using:				
millions of Canadian dollars	Total	Level 1	Level 2	Level 3	Net Asset Value (a)
Asset class					
Equity securities					
Canadian	469				469
Non-Canadian	2,267				2,267
Debt securities - Canadian					
Corporate	984				984
Government	3,251				3,251
Asset backed	4				4
Equities Venture capital	272				272
Cash	13	13			
Total plan assets at fair value	7,260	13	-	-	7,247

(a) Per ASU 2015-07, certain investments that are measured at fair value using the Net Asset Value (NAV) per share practical expedient have been re-categorized from the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the total value of plan assets.

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

	Pension benefits	
millions of Canadian dollars	**2016**	2015
For funded pension plans with accumulated benefit obligations in excess of plan assets:		
Projected benefit obligation	**-**	-
Accumulated benefit obligation	**-**	-
Fair value of plan assets	**-**	-
Accumulated benefit obligation less fair value of plan assets	**-**	-
For unfunded plans covered by book reserves:		
Projected benefit obligation	**553**	587
Accumulated benefit obligation	**525**	560

Estimated 2017 amortization from accumulated other comprehensive income

millions of Canadian dollars	Pension benefits	Other post-retirement benefits
Net actuarial loss (gain) (a)	179	14
Prior service cost (b)	11	-

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

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Cash flows

Benefit payments expected in:

millions of Canadian dollars	Pension benefits	Other post-retirement benefits
2017	420	30
2018	425	31
2019	435	31
2020	440	32
2021	440	33
2022 - 2026	2,201	175

In 2017, the company expects to make cash contributions of about $217 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 Canadian dollars	One percent increase	One percent decrease
Rate of return on plan assets:		
Effect on net benefit cost, before tax	(70)	70
Discount rate:		
Effect on net benefit cost, before tax	(90)	