Imperial

2019 annual financial statements and management discussion and analysis

140 YEARS anniversary

Annual financial statements and management's discussion and analysis of financial condition and operating results

For the year ended December 31, 2019

The following annual financial statements and management's discussion and analysis should be read in conjunction with the company's annual report on Form 10-K for the year ended December 31, 2019. Reference to Item 1A. "Risk factors" and specific page numbers in this document indicate the section and page numbers found in the company's annual report on Form 10-K. 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 are available online at www.sedar.com, www.sec.gov and the company's website www.imperialoil.ca.

Unless the context otherwise indicates, reference to the "company" or "Imperial" includes Imperial Oil Limited and its subsidiaries, and reference to ExxonMobil includes Exxon Mobil Corporation and its affiliates, as appropriate.

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.

Forward-looking statements

Statements of future events or conditions in this report, including projections, targets, expectations, estimates, and business plans are forward-looking statements. Forward-looking statements can be identified by words such as believe, anticipate, intend, propose, plan, goal, seek, project, predict, target, estimate, expect, strategy, outlook, schedule, future, continue, likely, may, should, will and similar references to future periods. Forward-looking statements in this report include, but are not limited to, references to being well positioned to participate in future investments and reduce commodity price risk; the company's long-term business outlook including demand, supply and energy mix; segment growth, competitive strategies and benefits from an integrated business model; Kearl production outlook and growth activities, including the impact from supplemental crushing facilities; Cold Lake production outlook and reservoir performance at Nabiye; the timing, cost, efficiency and production of the Aspen project, and the factors affecting a return to planned activity levels; potential impacts from carbon policy and climate related regulations; the impact on Chemical margins from continued industry capacity additions outpacing demand growth; the benefits to the Chemical business from integration with the Sarnia refinery and relationship with ExxonMobil; capital structure and financial strength as a competitive advantage, for risk mitigation and meeting funding requirements; the impact of any pending litigation, accounting standards and unrecognized tax benefits; anticipated capital, exploration and operating expenditures, including with respect to environmental protection; market risks and earnings sensitivities; and risks associated with use of derivative instruments.

Forward-looking statements are based on the company's current expectations, estimates, projections and assumptions at the time the statements are made. Actual future financial and operating results, including expectations and assumptions concerning demand growth and energy source, supply and mix; commodity prices, foreign exchange rates and general market conditions; production rates, growth and mix; project plans, timing, costs, technical evaluations and capacities and the company's ability to effectively execute on these plans and operate its assets; production life, resource recoveries and reservoir performance; cost savings; the adoption and impact of new facilities or technologies, including on capital efficiency, production and reductions to greenhouse gas emissions intensity; product sales; applicable laws and government policies, including taxation, climate change and production curtailment; industry capacity additions; financing sources and capital structure; and capital and environmental expenditures could differ materially depending on a number of factors. These factors include global, regional or local changes in supply and demand for oil, natural gas, and petroleum and petrochemical products and resulting price, differential and margin impacts; general economic conditions; transportation for accessing markets; political or regulatory events, including changes in law or government policy, applicable royalty rates, tax laws and production curtailment; the receipt, in a timely manner, of regulatory and third-party approvals; third party opposition to operations, projects and infrastructure; environmental risks inherent in oil and gas exploration and production activities; environmental regulation, including climate change and greenhouse gas regulation and changes to such regulation; currency exchange rates; availability and allocation of capital; availability and performance of third party service providers; unanticipated technical or operational difficulties; management effectiveness; commercial negotiations; project management and schedules and timely completion of projects; reservoir analysis and performance; unexpected technological developments; the results of research programs and new technologies, and ability to bring new technologies to commercial scale on a cost-competitive basis; operational hazards and risks; cybersecurity incidents; disaster response preparedness; the ability to develop or acquire additional reserves; and other factors discussed in Item 1A risk factors and Item 7 management's discussion and analysis of financial condition and results of operations of the company's annual report on Form 10-K for the year ended December 31, 2019.

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. Imperial'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 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.

Financial section

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Financial information (U.S. GAAP)

millions of Canadian dollars	**2019**	2018	2017	2016	2015
Revenues	**34,002**	34,964	29,125	25,049	26,756
Net income (loss):					
Upstream	**1,348**	(138)	(706)	(661)	(704)
Downstream	**961**	2,366	1,040	2,754	1,586
Chemical	**108**	275	235	187	287
Corporate and other	**(217)**	(189)	(79)	(115)	(47)
Net income (loss)	**2,200**	2,314	490	2,165	1,122
Cash and cash equivalents at year-end	**1,718**	988	1,195	391	203
Total assets at year-end	**42,187**	41,456	41,601	41,654	43,170
Long-term debt at year-end	**4,961**	4,978	5,005	5,032	6,564
Total debt at year-end	**5,190**	5,180	5,207	5,234	8,516
Other long-term obligations at year-end	**3,637**	2,943	3,780	3,656	3,597
Shareholders' equity at year-end	**24,276**	24,489	24,435	25,021	23,425
Cash flow from operating activities	**4,429**	3,922	2,763	2,015	2,167
Per share information (Canadian dollars)					
Net income (loss) per common share - basic	**2.88**	2.87	0.58	2.55	1.32
Net income (loss) per common share - diluted	**2.88**	2.86	0.58	2.55	1.32
Dividends per common share - declared	**0.85**	0.73	0.63	0.59	0.54

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	**2019**	2018	2017
Business uses: asset and liability perspective			
Total assets	**42,187**	41,456	41,601
Less: Total current liabilities excluding notes and loans payable	**(4,366)**	(3,753)	(3,934)
Total long-term liabilities excluding long-term debt	**(8,355)**	(8,034)	(8,025)
Add: Imperial's share of equity company debt	**24**	23	19
Total capital employed	**29,490**	29,692	29,661
Total company sources: Debt and equity perspective			
Notes and loans payable	**229**	202	202
Long-term debt	**4,961**	4,978	5,005
Shareholders' equity	**24,276**	24,489	24,435
Add: Imperial's share of equity company debt	**24**	23	19
Total capital employed	**29,490**	29,692	29,661

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 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	**2019**	2018	2017
Net income	**2,200**	2,314	490
Financing (after-tax), including Imperial's share of equity companies	**66**	77	48
Net income excluding financing	**2,266**	2,391	538
Average capital employed	**29,591**	29,677	29,967
Return on average capital employed (percent) – corporate total	**7.7**	8.1	1.8

Cash flows from operating activities and asset sales

Cash flows 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	**2019**	2018	2017
Cash flows from operating activities	**4,429**	3,922	2,763
Proceeds from asset sales	**82**	59	232
Total cash flows from operating activities and asset sales	**4,511**	3,981	2,995

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	**2019**	2018	2017
From Imperial's Consolidated statement of income			
Total expenses	**32,055**	32,026	28,842
Less:			
Purchases of crude oil and products	**20,946**	21,541	18,145
Federal excise tax and fuel charge	**1,808**	1,667	1,673
Financing	**93**	108	78
Subtotal	**22,847**	23,316	19,896
Imperial's share of equity company expenses	**76**	74	62
Total operating costs	**9,284**	8,784	9,008

Components of operating costs

millions of Canadian dollars	**2019**	2018	2017
From Imperial's Consolidated statement of income			
Production and manufacturing	**6,520**	6,121	5,586
Selling and general	**900**	908	883
Depreciation and depletion	**1,598**	1,555	2,172
Non-service pension and postretirement benefit	**143**	107	122
Exploration	**47**	19	183
Subtotal	**9,208**	8,710	8,946
Imperial's share of equity company expenses	**76**	74	62
Total operating costs	**9,284**	8,784	9,008

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 business model involving exploration for, and production of, crude oil and natural gas and manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals and a variety of specialty products.

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 depend on supply and demand and may be volatile on a short-term basis, Imperial’s investment decisions are grounded on fundamentals reflected in its long-term business outlook, and use 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. Volumes are based on individual field production profiles, which are also updated annually. Price ranges for crude oil, natural gas, refined products and chemical products are based on corporate plan assumptions developed annually and are utilized for investment evaluation purposes. Major investment opportunities are evaluated over a range of potential market conditions. 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

The “Long-term business outlook” is based on Exxon Mobil Corporation’s 2019 *Outlook for Energy*, which is used to help inform the company’s long-term business strategies and investment plans. By 2040, the world’s population is projected at around 9.2 billion people, or about 1.6 billion more than in 2017. Coincident with this population increase, the company expects worldwide economic growth to average close to 3 percent per year, with economic output nearly doubling by 2040. As economies and populations grow, and as living standards improve for billions of people, the need for energy is expected to continue to rise. Even with significant efficiency gains, global energy demand is projected to rise by about 20 percent from 2017 to 2040. This increase in energy demand is expected to be driven by developing countries (i.e., those that are not member nations of the Organization for Economic Co-operation and Development (OECD)). 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 helps drive global energy demand higher, increasing use of energy efficient technologies and practices, as well as lower-emission products 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’s economy through 2040, affecting energy requirements for power generation, transportation, industrial applications, and residential and commercial needs.

Global electricity demand is expected to increase approximately 60 percent from 2017 to 2040, with developing countries likely to account for about 85 percent of the increase. Consistent with this projection, power generation is expected to remain the largest and fastest growing major segment of global primary energy demand, supported by a wide variety of energy sources. The share of coal fired generation is likely to decline substantially and approach 25 percent of the world's electricity in 2040, versus nearly 40 percent in 2017, in part as a result of policies to improve air quality as well as reduce greenhouse gas emissions to address the risks related to climate change. From 2017 to 2040, the amount of electricity supplied using natural gas, nuclear power, and renewables is likely to grow by two-thirds, accounting for the entire growth in electricity supplies and offsetting the reduction of coal. Electricity from wind and solar is likely to increase about 400 percent, helping total renewables (including other sources, i.e., hydropower) to account for about 75 percent of the increase in electricity supplies worldwide through 2040. Total renewables will likely reach nearly 40 percent of global electricity supplies by 2040. Natural gas and nuclear are also expected to increase shares over the period to 2040, reaching almost 30 percent and about 15 percent of global electricity supplies respectively by 2040. Supplies of electricity by energy type will reflect significant differences across regions reflecting a wide range of factors including the cost and availability of various energy supplies and policy developments.

Energy for transportation – including cars, trucks, ships, trains and airplanes – is expected to increase by more than 25 percent from 2017 to 2040. Transportation energy demand is likely to account for approximately 60 percent of the growth in liquid fuels demand worldwide over this period. Light-duty vehicle demand for liquid fuels is projected to peak prior to 2025 and then decline to levels seen in the early-2010s by 2040 as the impact of better fuel economy and significant growth in electric cars, led by China, Europe, and the United States, work to offset growth in the worldwide car fleet of about 70 percent. By 2040, light-duty vehicles are expected to account for about 20 percent of global liquid fuels demand. During the same time period, nearly all the world's transportation fleets are likely to continue to run on liquid fuels, which are widely available and offer practical advantages in providing a large quantity of energy in small volumes.

Liquid fuels provide the largest share of global energy supplies today reflecting broad-based availability, affordability, ease of transportation, and fitness as a practical solution to meet a wide variety of needs. By 2040, global demand for liquid fuels is projected to grow to approximately 114 million oil-equivalent barrels per day, an increase of about 16 percent from 2017. The non-OECD share of global liquid fuels demand is expected to increase to about 65 percent by 2040, as liquid fuels demand in the OECD is likely to decline by close to 10 percent. Much of the global liquid fuels demand today is met by crude production from traditional conventional sources; these supplies will remain important, and significant development activity is expected to offset much of the natural declines from these fields. At the same time, a variety of emerging supply sources – including tight oil, deepwater, oil sands, natural gas liquids and biofuels – are expected to grow to help meet rising demand. The world's resource base is sufficient to meet projected demand through 2040 as technology advances continue to expand the availability of economic and lower carbon supply options. However, timely investments will remain critical to meeting global needs with reliable and affordable supplies.

Natural gas is a low-emission, versatile and practical fuel for a wide variety of applications, and it is expected to grow the most of any primary energy type from 2017 to 2040, meeting more than 40 percent of global energy demand growth. Global natural gas demand is expected to rise about 35 percent from 2017 to 2040, with about half of that increase coming from the Asia Pacific region. Significant growth in supplies of unconventional gas – the natural gas found in shale and other tight rock formations – will help meet these needs. In total, about 60 percent of the growth in natural gas supplies is expected to be from unconventional sources. At the same time, conventionally-produced natural gas is likely to remain the cornerstone of global supply, meeting more than two-thirds of worldwide demand in 2040. Liquefied natural gas (LNG) trade will expand significantly, meeting about 40 percent of the increase in global demand growth, with much of this supply expected to help 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 30 percent in 2040. Coal is currently the second largest source of energy, but it is likely to lose that position to natural gas in the 2020 to 2025 timeframe. The share of natural gas is expected to reach about 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 exceed 15 percent of global 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 nearly 250 percent from 2017 to 2040, when they will likely be just over 5 percent of the world energy mix.

The company anticipates that the world's available oil and gas resource base will grow not only from new discoveries, but also from increases in previously discovered fields. Technology will underpin these increases. The investments to develop and supply resources to meet global demand through 2040 will be significant – even if demand remains flat. This reflects a fundamental aspect of the oil and natural gas business as the International Energy Agency (IEA) describes in its *World Energy Outlook 2019*. According to the IEA's Stated Energy Policies Scenario, the investment required to meet oil and natural gas supply requirements worldwide over the period 2019 to 2040 will be about US$20 trillion (measured in 2018 dollars). In the IEA's Sustainable Development Scenario, which is in line with the objectives of the Paris Agreement on climate change, the investment need would still accumulate to US$13 trillion.

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 estimates of potential costs related to greenhouse gas emissions align with applicable provincial and federal regulations. Additionally, Imperial uses ExxonMobil's *Outlook for Energy* as a foundation for estimating energy supply and demand requirements from various energy sources and uses, and the *Outlook for Energy* takes into account policies established to reduce energy related greenhouse gas emissions. The climate accord reached at the Conference of the Parties (COP 21) in Paris set many new goals, and many related policies are still emerging. The *Outlook for Energy* reflects an environment with increasingly stringent climate policies and is consistent with the aggregation of Nationally Determined Contributions, which were submitted by signatories to the United Nations Framework Convention on Climate Change (UNFCCC) 2015 Paris Agreement. The *Outlook for Energy* seeks to identify potential impacts of climate related policies, which often target specific sectors. It estimates potential impacts of these policies on consumer energy demand by using various assumptions and tools – including, depending on the sector, application of a proxy cost of carbon or assessment of targeted policies (i.e., automotive fuel economy standards). As people and nations look for ways to reduce risks of global climate change, they will continue to need practical solutions that do not jeopardize the affordability or reliability of the energy they need.

Practical solutions to the world's energy and climate challenges will benefit from market competition in addition to well-informed, well-designed and transparent policy approaches that carefully weigh costs and benefits. Such policies are likely to help manage the risks of climate change while also enabling societies to pursue other high priority goals around the world – including clean air and water, access to reliable, affordable energy, and economic progress for all people. All practical and economically viable energy sources, both conventional and unconventional, will need to be pursued to continue meeting global energy demand, recognizing the scale and variety of worldwide energy needs, as well as the importance of expanding access to modern energy to promote better standards of living for billions of people.

The information provided in the "Long-term business outlook" includes internal estimates and forecasts based upon ExxonMobil's 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 North American markets. Imperial's Upstream business strategies guide the company's exploration, development, production, research and gas marketing activities. These strategies include maximizing asset reliability, accelerating development and application of high impact technologies, maximizing value by capturing new business opportunities and managing the existing portfolio, as well as pursuing sustainable improvements in organizational efficiency and effectiveness. These strategies are underpinned by a relentless focus on operations integrity, commitment to innovative technologies, disciplined approach to investing and cost management, 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 long-term growth. As future development projects bring new production online, Imperial expects growth from oil sands in-situ and mining, as well as unconventional resources, with the largest growth potential related to in-situ. Actual volumes will vary from year to year due to the factors described in Item 1A. “Risk factors”.

Kearl’s supplemental crushing facilities started operations in late 2019, with ramp-up of all units through early 2020. These facilities are expected to further improve reliability, reduce planned downtime, lower unit costs and enable the asset to achieve 240,000 barrels per day of total gross production in 2020. Gross bitumen production at Cold Lake was impacted by reservoir performance at Nabiye in 2019. The company anticipates this will continue to impact the asset’s near-term performance and, similar to 2019, expects gross bitumen production at Cold Lake to average 140,000 barrels per day in 2020. In 2019, the company slowed the pace of development of its $2.6 billion Aspen in-situ oil sands project given market uncertainty stemming from the Government of Alberta’s temporary mandatory production curtailment regulations and other industry competitiveness challenges. The decision to return to planned project activity levels will depend on several factors such as any subsequent government actions related to production curtailment and general market conditions.

The upstream industry environment continued to recover in 2019 as crude price differentials in the western Canadian market narrowed since the end of 2018. Prices for most of the company’s crude oil sold are referenced to Western Canada Select (WCS) and West Texas Intermediate (WTI) oil markets. On January 1, 2019, the Government of Alberta’s temporary mandatory production curtailment regulations came into effect. Consequently, the WTI / WCS differential narrowed from an average of approximately US$40 per barrel in the fourth quarter of 2018, to an average of about US$12 per barrel in the first quarter of 2019. Throughout 2019, the Government of Alberta continually eased the mandatory production limit, increased the base limit for production curtailment, and introduced several exemptions including a special production allowance providing temporary curtailment relief equivalent to incremental increases in shipments by rail. The duration of these regulations is uncertain. Imperial continually monitors the effects of these regulations and evaluates opportunities, including crude shipments by rail and the pace of the development of its Aspen in-situ oil sands project, as economically justified.

As described in more detail in Item 1A. “Risk factors”, environmental risks and climate related regulations could have negative impacts on the upstream business. On January 1, 2020, the International Maritime Organization’s mandate of a global 0.5 percent cap on the maximum level of sulphur in marine fuel came into effect. This new cap represents a significant reduction from the previous limit, and may adversely impact heavy crude price differentials in western Canada.

Imperial believes prices over the long-term will be driven by market supply and demand, with the demand side largely being a function of general economic activities, levels of prosperity, technology advances, consumer preference and government policies. On the supply side, prices may be significantly impacted by political events, logistics constraints, the actions of OPEC, governments 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 competitively position the company across a range of market conditions. These strategies include targeting industry leading performance in reliability, safety and operations integrity, as well as 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 quality, valued and differentiated products and services to customers.

Imperial owns and operates three refineries in Canada, with aggregate distillation capacity of 423,000 barrels per day. Refining margins are largely driven by differences in commodity prices and are a function of the difference between what a refinery pays for its raw materials (primarily crude oil) and the market prices for the range of products produced (primarily gasoline, heating oil, diesel oil, jet fuel, fuel oil and asphalt). 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 the global and regional marketplaces and are influenced by many factors, including global and regional supply / demand balances, inventory levels, industry refinery operations, import / export balances, currency fluctuations, seasonal demand, weather and political climate. Imperial's integration across the value chain, from refining to marketing, enhances overall value across the fuels business.

In 2019, Imperial's margins were negatively impacted by narrowing crude price differentials that resulted, in part, from the Government of Alberta's temporary mandatory curtailment regulations on crude oil production.

As described in more detail in Item 1A. "Risk factors", proposed carbon policy and other climate related regulations, as well as continued biofuels mandates, could have negative impacts on the downstream business.

Imperial supplies petroleum products to the motoring public through Esso and Mobil-branded sites and independent marketers. At the end of 2019, there were about 2,300 sites operating under a branded wholesaler model whereby Imperial supplies fuel to independent third parties who own and operate sites in alignment with Esso and Mobil brand standards.

Chemical

North America continued to benefit from abundant supplies of natural gas and gas liquids, providing both low cost energy and feedstock for steam crackers. In 2019, margins were adversely impacted by continued industry capacity additions outpacing demand growth. Imperial maintains a competitive advantage through continued operational excellence, investment and cost discipline, and integration of its chemical plant in Sarnia with the refinery. The company also benefits from its relationship with 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	**2019**	2018	2017
Net income (loss)	**2,200**	2,314	490

2019
Net income in 2019 was $2,200 million, or $2.88 per share on a diluted basis, compared to net income of $2,314 million or $2.86 per share in 2018. 2019 results include a favourable impact, largely non-cash, of $662 million associated with the Alberta corporate income tax rate decrease. On June 28, 2019, the Alberta government enacted a 4 percent decrease in the provincial tax rate, from 12 percent to 8 percent by 2022.

2018
Net income in 2018 was $2,314 million, or $2.86 per share on a diluted basis, an increase of $1,824 million compared to net income of $490 million or $0.58 per share in 2017. The prior year results included upstream non-cash impairment charges of $566 million.

Upstream

millions of Canadian dollars	**2019**	2018	2017
Net income (loss)	**1,348**	(138)	(706)

2019
Upstream net income was $1,348 million for the year, reflecting the favourable impact associated with the decreased Alberta corporate income tax rate of $689 million. Excluding this impact, 2019 net income was $659 million, up $797 million compared to a net loss of $138 million in 2018. Improved results reflect higher crude oil realizations of about $1,000 million, as well as higher volumes of about $350 million primarily at Syncrude and Norman Wells. Results were negatively impacted by higher royalties of about $230 million, higher operating expenses of about $190 million and lower Cold Lake volumes of about $120 million.

2018
Upstream recorded a net loss of $138 million in 2018, compared to a net loss of $706 million in 2017. Improved results reflect the absence of impairment charges of $566 million, higher Kearl volumes of about $210 million, lower royalties of about $80 million and favourable foreign exchange effects of about $50 million. These items were partially offset by higher operating costs of about $200 million, lower Cold Lake volumes of about $170 million and lower Canadian crude oil realizations of about $60 million.

Average realizations

Canadian dollars	**2019**	2018	2017
Bitumen (per barrel)	**50.02**	37.56	39.13
Synthetic oil (per barrel)	**74.47**	70.66	67.58
Conventional crude oil (per barrel)	**51.81**	41.84	53.51
Natural gas liquids (per barrel)	**22.83**	38.66	31.46
Natural gas (per thousand cubic feet)	**2.05**	2.43	2.58

2019
WTI averaged US$57.03 per barrel in 2019, down from US$65.03 per barrel in 2018. WCS averaged US$44.29 per barrel and US$38.71 per barrel for the same periods. The WTI / WCS differential narrowed to average approximately US$13 per barrel in 2019, from around US$26 per barrel in 2018. The Canadian dollar averaged US$0.75 in 2019, a decrease of US$0.02 from 2018.

Imperial's average Canadian dollar realizations for bitumen increased in 2019, supported primarily by an increase in WCS and lower diluent costs. Bitumen realizations averaged $50.02 per barrel, up from $37.56 per barrel in 2018. The company's average Canadian dollar realizations for synthetic crude increased relative to WTI, primarily due to the narrowing of the western Canadian light crude differential. Synthetic crude realizations averaged $74.47 per barrel, up from $70.66 per barrel in 2018.

2018
WTI averaged US$65.03 per barrel in 2018, up from US$50.85 per barrel in 2017. WCS averaged US$38.71 per barrel and US$38.95 per barrel for the same periods. The WTI / WCS differential widened to average approximately US$26 per barrel in 2018, from around US$12 per barrel in 2017. The Canadian dollar averaged US$0.77 in 2018, unchanged from 2017.

Imperial's average Canadian dollar realizations for bitumen declined generally in line with WCS, adjusted for changes in the exchange rate and transportation costs. Bitumen realizations averaged $37.56 per barrel in 2018, a decrease of $1.57 per barrel from 2017. The company's average Canadian dollar realizations for synthetic crude increased by $3.08 per barrel to average $70.66 per barrel in 2018, however the widening of the western Canadian light crude differential relative to WTI during the fourth quarter of 2018 negatively impacted synthetic crude realizations.

Crude oil and natural gas liquids (NGL) - production and sales (a)

thousands of barrels per day	**2019**		2018		2017	
	gross	**net**	gross	net	gross	net
Bitumen	**285**	**254**	293	255	288	255
Synthetic oil (b)	**73**	**65**	62	60	62	57
Conventional crude oil	**14**	**13**	5	5	4	3
Total crude oil production	**372**	**332**	360	320	354	315
NGLs available for sale	**2**	**1**	1	2	1	1
Total crude oil and NGL production	**374**	**333**	361	322	355	316
Bitumen sales, including diluent (c)	**387**		406		381	
NGL sales	**6**		6		6	

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

millions of cubic feet per day	**2019**		2018		2017	
	gross	**net**	gross	net	gross	net
Production (d) (e)	**145**	**144**	129	126	120	114
Production available for sale (f)		**108**		94		80

(a) Volume per day metrics are 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) Gross production of natural gas includes amounts used for internal consumption with the exception of the amounts re-injected.

(e) 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.

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

2019

Total gross production of Kearl bitumen averaged 205,000 barrels per day in 2019 (145,000 barrels Imperial's share), compared to 206,000 barrels per day (146,000 barrels Imperial's share) in 2018.

Gross production of Cold Lake bitumen averaged 140,000 barrels per day in 2019, compared to 147,000 barrels per day in 2018.

During 2019, the company's share of gross production from Syncrude averaged 73,000 barrels per day, up from 62,000 barrels per day in 2018. Higher production was mainly due to the absence of production impacts from the 2018 power disruption.

2018

Gross production of Kearl bitumen averaged 206,000 barrels per day in 2018 (146,000 barrels Imperial's share) up from 178,000 barrels per day (126,000 barrels Imperial's share) in 2017. Increased 2018 production reflects improved operational reliability associated with ore preparation, enhanced piping durability and feed management.

Gross production of Cold Lake bitumen averaged 147,000 barrels per day in 2018, compared to 162,000 barrels per day in 2017. Lower volumes were primarily due to production timing associated with steam management and planned maintenance.

During 2018, the company's share of gross production from Syncrude averaged 62,000 barrels per day, unchanged from 2017.

Downstream

millions of Canadian dollars	**2019**	2018	2017
Net income (loss)	**961**	2,366	1,040

2019
Downstream net income was $961 million, compared to $2,366 million in 2018. Earnings were negatively impacted by lower margins of about $1,130 million, reliability events of about $150 million, including the fractionation tower incident at Sarnia, higher net planned turnaround impacts of about $140 million, and lower sales volumes of about $130 million. These factors were partially offset by favourable foreign exchange impacts of about $90 million.

2018
Downstream net income was $2,366 million, an increase of $1,326 million versus the prior year. Higher earnings primarily reflect stronger margins of about $1,530 million, partially offset by the absence of a $151 million gain on the sale of a surplus property in 2017.

Refinery utilization

thousands of barrels per day (a)	**2019**	2018	2017
Total refinery throughput (b)	**353**	392	383
Refinery capacity at December 31	**423**	423	423
Utilization of total refinery capacity (percent)	**83**	93	91

Sales

thousands of barrels per day (a)	**2019**	2018	2017
Gasolines	**249**	255	257
Heating, diesel and jet fuels	**167**	183	177
Heavy fuel oils	**21**	26	18
Lube oils and other products	**38**	40	40
Net petroleum product sales	**475**	504	492

(a) Volume per day metrics are calculated by dividing the volume for the period by the number of calendar days in the period.
(b) Crude oil and feedstocks sent directly to atmospheric distillation units.

2019
Refinery throughput averaged 353,000 barrels per day in 2019, compared to 392,000 barrels per day in 2018. Capacity utilization was 83 percent, compared to 93 percent in 2018. Reduced throughput was mainly due to higher planned turnaround activities and impacts from the Sarnia fractionation tower incident. Petroleum product sales were 475,000 barrels per day in 2019, compared to 504,000 barrels per day in 2018. Lower petroleum product sales were mainly due to lower refinery throughput.

2018
Refinery throughput averaged 392,000 barrels per day in 2018, up from 383,000 barrels per day in 2017. Capacity utilization increased to 93 percent from 91 percent in 2017. Petroleum product sales were 504,000 barrels per day in 2018, up from 492,000 barrels per day in 2017. Sales growth continues to be driven by optimization across the full downstream value chain, and the expansion of Imperial's logistics capabilities.

Chemical

millions of Canadian dollars	**2019**	2018	2017
Net income (loss)	**108**	275	235

Sales

thousands of tonnes	**2019**	2018	2017
Polymers and basic chemicals	**575**	602	564
Intermediate and others	**157**	205	210
Total petrochemical sales	**732**	807	774

2019
Chemical net income was $108 million in 2019, compared to $275 million in 2018, primarily due to lower margins.

2018
Chemical net income was $275 million, an increase of $40 million versus the prior year, reflecting higher margins and volumes.

Corporate and other

millions of Canadian dollars	**2019**	2018	2017
Net income (loss)	**(217)**	(189)	(79)

2019
Corporate and other expenses were $217 million in 2019, compared to $189 million in 2018.

2018
For 2018, Corporate and other expenses were $189 million, compared to $79 million in 2017. As part of the implementation of the Financial Accounting Standards Board's update, Compensation – Retirement Benefits (Topic 715): *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*, beginning January 1, 2018, Corporate and other includes all non-service pension and postretirement benefit expenses. Prior to 2018, the majority of these costs were allocated to the operating segments.

Liquidity and capital resources

Sources and uses of cash

millions of Canadian dollars	**2019**	2018	2017
Cash provided by (used in)			
Operating activities	**4,429**	3,922	2,763
Investing activities	**(1,704)**	(1,559)	(781)
Financing activities	**(1,995)**	(2,570)	(1,178)
Increase (decrease) in cash and cash equivalents	**730**	(207)	804
Cash and cash equivalents at end of year	**1,718**	988	1,195

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 depending on funding status. The most recent valuation of the company's registered retirement plans was completed as at December 31, 2016. A valuation of the company's registered retirement plans as at December 31, 2019 is expected to be completed in 2020. The company contributed $211 million to the registered retirement plans in 2019. Future funding requirements are not expected to affect the company's existing capital investment plans or its ability to pursue new investment opportunities.

Cash flow from operating activities

2019
Cash flow generated from operating activities was $4,429 million in 2019, up from $3,922 million in 2018, primarily reflecting favourable working capital effects, partially offset by lower earnings excluding the impact associated with the Alberta corporate income tax rate decrease.

2018
Cash flow generated from operating activities was $3,922 million in 2018, up from $2,763 million in 2017, primarily reflecting higher earnings, partially offset by unfavourable working capital effects.

Cash flow from investing activities

2019
Investing activities used net cash of $1,704 million in 2019, compared with $1,559 million used in 2018, primarily reflecting higher additions to property, plant and equipment.

2018
Investing activities used net cash of $1,559 million in 2018, compared with $781 million used in 2017, reflecting higher additions to property, plant and equipment, and lower proceeds from asset sales.

Cash flow from financing activities

2019
Cash used in financing activities was $1,995 million in 2019, compared with $2,570 million used in 2018.

At the end of 2019, total debt outstanding was $5,190 million, compared with $5,180 million at the end of 2018.

In September 2019, the company extended the maturity date of its existing long-term, variable-rate, Canadian dollar loan from ExxonMobil to June 30, 2025. All other terms and conditions remained unchanged.

In November 2019, the company increased the capacity of its non-interest bearing, revolving demand loan with ExxonMobil from $75 million to $150 million. The loan represents ExxonMobil's share of a working capital facility required to support purchasing, marketing, transportation and derivative arrangements for crude oil and diluent products undertaken by Imperial on behalf of ExxonMobil. At December 31, 2019 the company had borrowed $111 million under this arrangement.

In November 2019, the company extended the maturity date of its existing $250 million committed long-term line of credit to November 2021. The company has not drawn on the facility.

In December 2019, the company extended the maturity date of its existing $250 million committed short-term line of credit to December 2020. The company has not drawn on the facility.

During 2019, the company, under its share purchase program, purchased about 38.7 million shares for $1,373 million, including shares purchased from Exxon Mobil Corporation.

Dividends paid in 2019 were $631 million. The per share dividend paid in 2019 was $0.82, up from $0.70 in 2018.

2018
Cash used in financing activities was $2,570 million in 2018, compared with $1,178 million used in 2017.

At the end of 2018, total debt outstanding was $5,180 million, compared with $5,207 million at the end of 2017.

In November 2018, the company extended the maturity date of its existing $250 million committed long-term line of credit to November 2020. The company has not drawn on the facility.

In December 2018, the company extended the maturity date of its existing $250 million committed short-term line of credit to December 2019. The company has not drawn on the facility.

During 2018, the company, under its share purchase program, purchased about 48.7 million shares for $1,971 million, including shares purchased from Exxon Mobil Corporation.

Dividends paid in 2018 were $572 million. The per share dividend paid in 2018 was $0.70, up from $0.62 in 2017.

Financial strength

The table below shows Imperial's consolidated debt-to-capital ratio. The data demonstrates the company's creditworthiness:

percent At December 31	**2019**	2018	2017
Debt to capital (a)	**18**	18	18

(a) Debt, defined as the sum of Notes and loans payable and Long-term debt (page 67), divided by capital, defined as the sum of debt and Total shareholders' equity (page 67).

Debt-related interest incurred in 2019, before capitalization of interest, was $138 million, compared with $133 million in 2018. The average effective interest rate on the company's debt was 2.7 percent in 2019, compared with 2.5 percent in 2018.

The company's financial strength represents a competitive advantage of strategic importance providing it the opportunity to readily access capital markets under the full range of market conditions and enables the company to take on large, long-term capital commitments in the pursuit of maximizing shareholder value.

Commitments

The following table shows the company's commitments outstanding at December 31, 2019. 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	Note reference	2020	2021 to 2022	2023 to 2024	2025 and beyond	Total
Long-term debt excluding finance lease obligations (a)	15	**-**	**4,447**	**-**	**-**	**4,447**
Operating and finance leases (b)	14	**194**	**203**	**119**	**1,116**	**1,632**
Firm capital commitments (c)		**217**	**111**	**66**	**-**	**394**
Pension and other postretirement obligations (d)	5	**275**	**120**	**122**	**1,363**	**1,880**
Asset retirement obligations (e)	6	**76**	**64**	**47**	**1,213**	**1,400**
Other long-term purchase agreements (f)		**883**	**1,599**	**1,470**	**8,637**	**12,589**

(a) Long-term debt includes a loan from an affiliated company of ExxonMobil of $4,447 million. 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 finance and operating leases, both commenced and non-commenced, are shown on an undiscounted basis. Leases are primarily associated with storage tanks, rail cars, marine vessels, transportation facilities and service agreements.

(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 are shown on an undiscounted basis.

(d) The amount by which the benefit obligations exceeded the fair value of fund assets for pension and other postretirement plans at year end. The payments by period include expected contributions to funded pension plans in 2020 and estimated benefit payments for unfunded plans in all years.

(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 transportation services agreements, raw material supply and community benefits agreements.

Unrecognized tax benefits totalling $35 million have not been included in the company's commitments table because the company does not expect there will be any cash impact from the final settlements as sufficient funds have been deposited with the Canada Revenue Agency. Further details on the unrecognized tax benefits can be found in note 4 to the financial statements on page 78.

Litigation and other contingencies

As discussed in note 10 to the consolidated financial statements on page 87, 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 10, Imperial was contingently liable at December 31, 2019, for guarantees relating to performance under contracts. 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

Capital and exploration expenditures represent the combined total of additions at cost to property, plant and equipment; exploration expenses on a before-tax basis from the Consolidated statement of income; and the company's share of similar costs for equity companies. Capital and exploration expenditures exclude the purchase of carbon emission credits. While Imperial's management is responsible for all investments and elements of net income, particular focus is placed on managing the controllable aspects of this group of expenditures.

millions of Canadian dollars	**2019**	2018
Upstream (a)	**1,248**	991
Downstream	**484**	383
Chemical	**34**	25
Corporate and other	**48**	28
Total	**1,814**	1,427

(a) Exploration expenses included.

Total capital and exploration expenditures were $1,814 million in 2019, an increase of $387 million from 2018.

For the Upstream segment, capital and exploration expenditures were $1,248 million in 2019, compared with $991 million in 2018. Investments were primarily related to growth activities including investment in supplemental crushing capacity at Kearl, further development of unconventional assets, and expenditures on the Aspen in-situ project.

For the Downstream segment, capital expenditures were $484 million in 2019, compared with $383 million in 2018. Investments were primarily in support of enhancing the company's distribution network as well as refinery projects to improve reliability, feedstock flexibility, energy efficiency and environmental performance.

Total capital and exploration expenditures are expected to range between $1.6 billion to $1.7 billion in 2020. 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.

Imperial's earnings are influenced by North American crude oil benchmark prices as well as changes in the differentials between these benchmarks and western Canadian prices for light and heavy crude oil. Imperial's integrated business model reduces the company's risk from changes in commodity prices. For instance, when light and heavy differentials between North American crude benchmarks and western Canadian prices widen together, Imperial is able to mitigate the impact of widening differentials on the Upstream through integration with Downstream investments in refineries, pipeline commitments and the Edmonton rail terminal. As an example, the negative impact of a widening differential in the Upstream is more than offset by the benefit of lower feedstock costs in the Downstream.

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

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.

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

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 sources 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.

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, which shows the estimated annual effect, under current conditions, on the company's after-tax net income. For any given period, the extent of actual benefit or detriment will be dependent on the price movements of individual types of crude oil and products, production and sales volumes, transportation capacity, costs and egress methods, and other factors. Accordingly, changes in benchmark prices for crude oil and crude oil differentials, and other factors listed in the table following, only provide broad indicators of changes in the earnings experienced in any particular period.

Earnings sensitivities (a)

millions of Canadian dollars, after tax		
One dollar (U.S.) per barrel increase (decrease) in crude oil prices	+ (-)	**105**
One dollar (U.S.) per barrel increase (decrease) in light and heavy crude price differentials (b)	+ (-)	**40**
Ten cents per thousand cubic feet decrease (increase) in natural gas prices	+ (-)	**7**
One dollar (U.S.) per barrel increase (decrease) in refining 2-1-1 margins (c)	+ (-)	**140**
One cent (U.S.) per pound increase (decrease) in sales margins for polyethylene	+ (-)	**7**
One cent decrease (increase) in the value of the Canadian dollar versus the U.S. dollar	+ (-)	**100**

(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 market conditions. They may not apply proportionately to larger fluctuations.

(b) Light and heavy crude differentials represent the difference between WTI benchmark prices and western Canadian prices for light and heavy crudes.

(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 demand for crude oil, natural gas, petroleum products and petrochemical products are generally linked closely with economic growth. 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. Although price levels of crude oil and natural gas may rise and fall significantly over the short to medium term due to global economic conditions, political events, decisions by OPEC, governments and other factors, industry economics over the long term will continue to be driven by market supply and demand. Accordingly, the company evaluates the viability of its major investments over a range of prices.

The global energy markets can give rise to extended periods in which market conditions are adverse to one or more of the company’s businesses. Such conditions, along with the capital-intensive nature of the industry and very long lead times associated with many of 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. Where such intersegment sales take place, they are the result of efficiencies and competitive advantages from integrated business segments and refinery and chemical complexes. The company’s intersegment sales include crude oil produced by the Upstream and sold to the Downstream, as well as sales between refineries and the chemical plant related to raw materials, feedstocks and finished products. All intersegment sales are at market based prices. Refer to Note 3 for additional information on intersegment revenue.

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.

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 exchange rates. In addition, the company may use commodity-based contracts, including derivatives, to manage commodity price risk and for trading purposes. The company’s derivatives are not accounted for under hedge accounting. Credit risk associated with the company’s derivative position is mitigated by several factors, including the use of derivative clearing exchanges and the quality of and financial limits placed on derivative counterparties. No material market or credit risks to the company’s financial position, results of operations or liquidity exist as a result of the derivatives described in note 7 on page 85. The company maintains a system of controls that includes 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 (U.S. GAAP). U.S. 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 business model involving exploration for, and production of, crude oil and natural gas and manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals and a variety of specialty products. 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 70.

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 pressures. The estimation of proved reserves is controlled by the company through long-standing approval guidelines. Reserves changes are made within a well-established, disciplined process driven by qualified 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 reserves targets to determine compensation. Key features of the reserves 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 U.S. Securities and Exchange Commission (SEC) 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-day-of-the-month oil and natural gas prices during the reporting year.

  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 and facilities 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 89 percent of total proved reserves at year-end 2019, unchanged from 2018. 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, government policy, consumer preferences 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-day-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.

At year-end 2016, downward revisions of proved developed and undeveloped bitumen reserves were a result of low prices. The entire 2.5 billion barrels of bitumen at Kearl and approximately 0.2 billion barrels of bitumen at Cold Lake no longer qualified as proved reserves under the U.S. Securities and Exchange Commission definition of proved reserves.

At year-end 2017, an additional 0.3 billion barrels of bitumen at Kearl and Cold Lake qualified as proved reserves resulting from improved prices in the year.

As a result of improved prices in 2018, an additional 2.3 billion barrels of bitumen at Kearl qualified as proved reserves at year-end 2018.

In 2019, downward revisions to proved bitumen reserves were driven by technical and development plan updates at Kearl, resulting in a decrease of 0.2 billion barrels, partially offset by an increase of 0.1 billion barrels at Cold Lake associated with an end of field life change driven by pricing. Downward revisions to proved synthetic oil reserves were a result of higher royalty obligations at Syncrude driven by pricing. Changes to liquids and natural gas proved reserves were the result of updated development plans at the Montney and Duvernay unconventional assets and the divestment of conventional properties.

Under the terms of certain contractual arrangements or government royalty regimes, lower prices can also increase proved reserves attributable to Imperial. The company's operating decisions and its outlook for future production volumes are not impacted by proved reserves as disclosed under the U.S. Securities and Exchange Commission (SEC) definition.

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 substantially de-booked and that property continues to produce such that the resulting depreciation charge does not result in an equitable allocation of cost over the expected life, assets will be depreciated using a unit-of-production method based on reserves determined at the most recent SEC price which results in a more meaningful quantity of proved reserves, appropriately adjusted for production and technical changes. This approach was applied in 2017 and 2018, with the corresponding effect on depreciation expense being immaterial when compared to prior periods. In 2019 and 2020, all properties have sufficient reserves at current SEC prices which will enable equitable allocation of cost over the economic lives of the Upstream assets. The effect of this approach compared to prior periods is 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 on an ongoing basis whenever events or changes in circumstances indicate 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.

Asset valuation analysis, profitability reviews and other periodic control processes assist Imperial in assessing whether events or changes in circumstances indicate 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 believes prices over the long-term must be sufficient to generate investments in energy supply to meet global demand. Although prices will occasionally drop significantly, industry prices over the long-term will continue to be driven by market supply and demand fundamentals. On the supply side, industry production from mature fields is declining. This is being offset by investments to generate production from new discoveries, field developments and technological and efficiency advancements. OPEC investment activities and production policies also have an impact on world oil supplies. The demand side is largely a function of general economic activities and levels of prosperity. 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 development 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 to its long-term oil prices or natural gas prices or margin ranges, the company may consider that situation, in conjunction with other events or 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 yearly average of first-day-of-the-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.

The company has a robust process to monitor for indicators of potential impairment across its asset groups throughout the year. This process is aligned with the requirements of *ASC 360* and relies on the company's planning and budgeting cycle. If events or changes in circumstances indicate that the carrying value of an asset 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 assumptions of future capital allocations, crude oil and natural gas commodity prices, including price differentials, refining and chemical margins, volumes, development and operating costs, foreign currency exchange rates and inflation rates. Volumes are based on projected field and facility production profiles, throughput, or sales. Management's estimate of upstream production volumes used for projected cash flows makes use of proved reserve quantities and may include risk-adjusted unproved reserve quantities. Cash flow estimates for impairment testing exclude the effects of derivative instruments.

An asset group is impaired if its estimated future 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.

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

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 4.5 percent used in 2019, compares to actual returns of 8.1 percent and 6.6 percent achieved over the last 10- and 20-year periods respectively, ending December 31, 2019. If different assumptions are used, the obligation and expense could increase or decrease as a result. As an indication of the company's potential exposure to changes in the critical assumptions such as the expected rate of return on plan assets and the discount rate for measuring the benefits obligation, a reduction of 1 percent in the discount rate would increase the plan benefits obligation by approximately $1,820 million. Similarly, a reduction of 1 percent in the long-term rate of return on plan assets would increase the annual pension expense by approximately $75 million before tax. 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 benefits expense represented about 1 percent of total expenses in 2019.

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 2019, the obligations were discounted at 6 percent and the accretion expense was $80 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 16 to the consolidated financial statements on page 93.

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 4 to the consolidated financial statements starting on page 78.

Recently issued accounting standards

Effective January 1, 2020, Imperial adopted the Financial Accounting Standards Board's update, *Financial Instruments - Credit Losses (Topic 326)*, as amended. The standard requires a valuation allowance for credit losses be recognized for certain financial assets that reflects the current expected credit loss over the asset's contractual life. The valuation allowance considers the risk of loss, even if remote and considers past events, current conditions and expectations of the future. The January 1, 2020 estimated cumulative effect adjustment to "Earnings reinvested" related to implementation of the Credit Losses standard is expected to be de minimis.

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, 2019.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the company’s internal control over financial reporting as of December 31, 2019, as stated in their report which is included herein.

/s/ Bradley W. Corson

B.W. Corson
Chairman, president and
chief executive officer

/s/ Daniel E. Lyons

D.E. Lyons
Senior vice-president,
finance and administration, and controller
(Principal accounting officer and principal financial officer)

February 26, 2020

Report of independent registered public accounting firm

To the Board of Directors and Shareholders of Imperial Oil Limited

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Imperial Oil Limited and its subsidiaries (together, the Company) as of December 31, 2019 and 2018, and the related consolidated statements of income, comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's 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 opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. 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, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. 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.

Definition and Limitations of Internal Control over Financial Reporting

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.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

The impact of proved oil and natural gas reserves on upstream property, plant and equipment, net

As described in Notes 1 and 3 to the consolidated financial statements, the Company's upstream property, plant and equipment (PP&E) balance, net was $31.2 billion as of December 31, 2019, and the related depreciation, depletion and amortization (DD&A) expense for the year ended December 31, 2019 was $1.4 billion. Management uses the successful efforts method to account for its exploration and production activities. Costs incurred to purchase, lease, or otherwise acquire a property (whether unproved or proved) are capitalized when incurred. As disclosed by management, proved oil and natural gas reserves quantities are used as the basis to calculate unit-of-production depreciation rates for most upstream assets. The estimation of proved oil and natural gas reserves is an ongoing process based on technical evaluations, commercial and market assessments, and detailed analysis of well information such as flow rates and reservoir pressures, and development and production costs, among other factors. As management has disclosed, reserves changes are made within a well-established, disciplined process driven by qualified geoscience and engineering professionals, assisted by the Reserves Management Group (together, management's specialists).

The principal consideration for our determination that performing procedures relating to the impact of proved oil and natural gas reserves on upstream PP&E, net is a critical audit matter is that there was significant judgment by management, including the use of management's specialists, when developing the estimates of proved oil and natural gas reserves. This in turn led to a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating evidence obtained related to the significant assumptions used by management, including development costs and production volumes.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved oil and natural gas reserves and the calculation of DD&A expense. These procedures also included, among others (i) testing the completeness, accuracy, and relevance of underlying data used in developing management's estimates, (ii) evaluating the significant assumptions used by management in developing these estimates, including development costs and production volumes, and (iii) testing the unit-of-production rates used to calculate DD&A expense. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the estimates of proved oil and natural gas reserves. As a basis for using this work, the specialists' qualifications and objectivity were understood, as well as the methods and assumptions used by the specialists. The procedures performed also included tests of data used by management's specialists and an evaluation of the specialists' findings. Evaluating the significant assumptions relating to the estimates of proved oil and natural gas reserves also involved obtaining evidence to support the reasonableness of the assumptions, including whether the assumptions used were reasonable considering the past performance of the Company, and whether they were consistent with evidence obtained in other areas of the audit.

/s/ PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Canada
February 26, 2020

We have served as the Company's auditor since 1934.

Consolidated statement of income (U.S. GAAP)

millions of Canadian dollars For the years ended December 31	2019	2018	2017
Revenues and other income			
Revenues (a)	**34,002**	34,964	29,125
Investment and other income (note 9)	**99**	135	299
Total revenues and other income	**34,101**	35,099	29,424
Expenses			
Exploration (note 16)	**47**	19	183
Purchases of crude oil and products (b)	**20,946**	21,541	18,145
Production and manufacturing (c)	**6,520**	6,121	5,586
Selling and general (c)	**900**	908	883
Federal excise tax and fuel charge	**1,808**	1,667	1,673
Depreciation and depletion	**1,598**	1,555	2,172
Non-service pension and postretirement benefit	**143**	107	122
Financing (d) (note 13)	**93**	108	78
Total expenses	**32,055**	32,026	28,842
Income (loss) before income taxes	**2,046**	3,073	582
Income taxes (note 4)	**(154)**	759	92
Net income (loss)	**2,200**	2,314	490
Per share information (Canadian dollars)			
Net income (loss) per common share - basic (note 11)	**2.88**	2.87	0.58
Net income (loss) per common share - diluted (note 11)	**2.88**	2.86	0.58
(a) Amounts from related parties included in revenues, (note 17).	**8,569**	6,383	4,110
(b) Amounts to related parties included in purchases of crude oil and products, (note 17).	**3,305**	4,092	2,687
(c) Amounts to related parties included in production and manufacturing, and selling and general expenses, (note 17).	**628**	566	544
(d) Amounts to related parties included in financing, (note 17).	**98**	89	60

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

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

millions of Canadian dollars For the years ended December 31	**2019**	2018	2017
Net income (loss)	**2,200**	2,314	490
Other comprehensive income (loss), net of income taxes			
Postretirement benefits liability adjustment (excluding amortization)	**(505)**	158	(54)
Amortization of postretirement benefits liability adjustment included in net periodic benefit costs	**111**	140	136
Total other comprehensive income (loss)	**(394)**	298	82
Comprehensive income (loss)	**1,806**	2,612	572

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

Consolidated balance sheet (U.S. GAAP)

millions of Canadian dollars At December 31	**2019**	2018
Assets		
Current assets		
Cash	**1,718**	988
Accounts receivable, less estimated doubtful accounts (a)	**2,699**	2,529
Inventories of crude oil and products (note 12)	**1,296**	1,297
Materials, supplies and prepaid expenses	**616**	541
Total current assets	**6,329**	5,355
Investments and long-term receivables (b)	**891**	857
Property, plant and equipment, less accumulated depreciation and depletion	**34,203**	34,225
Goodwill	**186**	186
Other assets, including intangibles, net	**578**	833
Total assets	**42,187**	41,456
Liabilities		
Current liabilities		
Notes and loans payable (c) (note 13)	**229**	202
Accounts payable and accrued liabilities (a) (note 12)	**4,260**	3,688
Income taxes payable	**106**	65
Total current liabilities	**4,595**	3,955
Long-term debt (d) (note 15)	**4,961**	4,978
Other long-term obligations (e) (note 6)	**3,637**	2,943
Deferred income tax liabilities (note 4)	**4,718**	5,091
Total liabilities	**17,911**	16,967
Commitments and contingent liabilities (note 10)		
Shareholders' equity		
Common shares at stated value (f) (note 11)	**1,375**	1,446
Earnings reinvested	**24,812**	24,560
Accumulated other comprehensive income (loss) (note 18)	**(1,911)**	(1,517)
Total shareholders' equity	**24,276**	24,489
Total liabilities and shareholders' equity	**42,187**	41,456

(a) Accounts receivable, less estimated doubtful accounts included net amounts receivable from related parties of $1,007 million (2018 – $666 million), (note 17).
(b) Investments and long-term receivables included amounts from related parties of $296 million (2018 – $146 million), (note 17).
(c) Notes and loans payable included amounts to related parties of $111 million (2018 – $75 million), (note 17).
(d) Long-term debt included amounts to related parties of $4,447 million (2018 – $4,447 million), (note 17).
(e) Other long-term obligations included amounts to related parties of $0 million (2018 – $15 million), (note 17).
(f) Number of common shares authorized and outstanding were 1,100 million and 744 million, respectively (2018 – 1,100 million and 783 million, respectively), (note 11).

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

Approved by the directors.

/s/ Bradley W. Corson

B.W. Corson
Chairman, president and
chief executive officer

/s/ Daniel E. Lyons

D.E. Lyons
Senior vice-president,
finance and administration, and controller

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

millions of Canadian dollars At December 31	**2019**	2018	2017
Common shares at stated value (note 11)			
At beginning of year	**1,446**	1,536	1,566
Issued under the stock option plan	**-**	-	-
Share purchases at stated value	**(71)**	(90)	(30)
At end of year	**1,375**	1,446	1,536
Earnings reinvested			
At beginning of year	**24,560**	24,714	25,352
Net income (loss) for the year	**2,200**	2,314	490
Share purchases in excess of stated value	**(1,302)**	(1,881)	(597)
Dividends declared	**(646)**	(587)	(531)
At end of year	**24,812**	24,560	24,714
Accumulated other comprehensive income (loss) (note 18)			
At beginning of year	**(1,517)**	(1,815)	(1,897)
Other comprehensive income (loss)	**(394)**	298	82
At end of year	**(1,911)**	(1,517)	(1,815)
Shareholders' equity at end of year	**24,276**	24,489	24,435

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

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

millions of Canadian dollars Inflow (outflow) For the years ended December 31	**2019**	2018	2017
Operating activities			
Net income (loss)	**2,200**	2,314	490
Adjustments for non-cash items:			
Depreciation and depletion	**1,598**	1,509	2,172
Impairment of intangible assets	**-**	46	-
(Gain) loss on asset sales (note 9)	**(46)**	(54)	(220)
Deferred income taxes and other	**(237)**	806	321
Changes in operating assets and liabilities:			
Accounts receivable	**(170)**	224	(689)
Inventories, materials, supplies and prepaid expenses	**(74)**	(338)	(83)
Income taxes payable	**41**	8	(431)
Accounts payable and accrued liabilities	**1,010**	(764)	678
All other items - net (a) (c)	**107**	171	525
Cash flows from (used in) operating activities	**4,429**	3,922	2,763
Investing activities			
Additions to property, plant and equipment (a)	**(1,636)**	(1,491)	(993)
Proceeds from asset sales (note 9)	**82**	59	232
Additional investments	**-**	-	(1)
Loan to equity company	**(150)**	(127)	(19)
Cash flows from (used in) investing activities	**(1,704)**	(1,559)	(781)
Financing activities			
Short-term debt - net (note 13)	**36**	-	-
Reduction in finance lease obligations (note 15)	**(27)**	(27)	(27)
Dividends paid	**(631)**	(572)	(524)
Common shares purchased (note 11)	**(1,373)**	(1,971)	(627)
Cash flows from (used in) financing activities	**(1,995)**	(2,570)	(1,178)
Increase (decrease) in cash	**730**	(207)	804
Cash at beginning of year	**988**	1,195	391
Cash at end of year (b)	**1,718**	988	1,195

(a) The impact of carbon emission programs are included in Additions to property, plant and equipment, and All other items - net.

(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.

(c) Included contributions to registered pension plans.	**(211)**	(203)	(212)
Income taxes (paid) refunded.	**145**	(82)	(231)
Interest (paid), net of capitalization.	**(91)**	(110)	(76)

Non-cash transactions

In 2019, the company removed $570 million of assets and corresponding liabilities associated with the Government of Ontario's revocation of its cap and trade legislation. The impact of this removal was not reflected in "Accounts payable and accrued liabilities" and "All other items - net" lines on the Consolidated statement of cash flows as it was not a cash transaction.

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

Notes to consolidated financial statements

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

The company's principal business is energy, involving the exploration for, and production of, crude oil and natural gas and manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals and a variety of specialty products.

The consolidated financial statements have been prepared in accordance with United States Generally Accepted Accounting Principles (U.S. GAAP), which 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 2019 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. Imperial Oil Resources Limited is the only significant subsidiary included in the consolidated financial statements and is wholly owned by Imperial Oil Limited. 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.

Revenues
Imperial generally sells crude oil, natural gas and petroleum and chemical products under short-term agreements at prevailing market prices. In some cases, products may be sold under long-term agreements, with periodic price adjustments to reflect market conditions.

Revenue is recognized at the amount the company expects to receive when the customer has taken control, which is typically when title transfers and the customer has assumed the risks and rewards of ownership. The prices of certain sales are based on price indices that are sometimes not available until the next period. In such cases, estimated realizations are accrued when the sale is recognized, and are finalized when final information is available. Such adjustments to revenue from performance obligations satisfied in previous periods are not significant. Payment for revenue transactions is typically due within 30 days.

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. 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.

Future volume delivery obligations that are unsatisfied at the end of the period are expected to be fulfilled through ordinary production or purchases. These performance obligations are based on market prices at the time of the transaction and are fully constrained due to market price volatility.

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.

"Revenues" and "Accounts receivable, less estimated doubtful accounts" primarily arise from contracts with customers. Long-term receivables are primarily from non-customers. Contract assets are mainly from marketing assistance programs and are not significant. Contract liabilities are mainly customer prepayments, loyalty programs and accruals of expected volume discounts, and are not significant.

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.

Derivative instruments
Imperial may use derivative instruments for trading purposes and to offset exposures associated with commodity prices, currency exchange rates and interest rates that arise from existing assets, liabilities, firm commitments and forecasted transactions. All derivative instruments, except those designated as normal purchase and normal sale, are recorded at fair value. Derivative assets and liabilities with the same counterparty are netted if the right of offset exists and certain other criteria are met. Collateral payables or receivables are netted against derivative assets and derivative liabilities respectively.

Recognition and classification of the gain or loss that results from adjusting a derivative to fair value depends on the purpose for the derivative. The gains and losses resulting from changes in the fair value of derivatives are recorded under "Revenues" or "Purchases of crude oil and products" on the Consolidated statement of 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 and 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.

Inventories
Inventories are recorded at the lower of current market value or cost. 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 location. Selling and general expenses are reported as period costs and excluded from inventory costs. Inventories of materials and supplies are valued at cost or less.

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. Investments in equity securities, other than consolidated subsidiaries and equity method investments, are measured at fair value, with changes in the fair value recognized in net income. The company uses a modified approach for equity securities that do not have a readily determinable fair value. This modified approach measures investments at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions in similar investment of the same issuer. Dividends from these 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 not meeting these 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 dry holes, 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.

To the extent that proved reserves for a property are substantially de-booked and that property continues to produce such that the resulting depreciation charge does not result in an equitable allocation of cost over the expected life, assets will be depreciated using a unit-of-production method based on reserves determined at the most recent SEC price which results in a more meaningful quantity of proved reserves, appropriately adjusted for production and technical changes. This approach was applied in 2017 and 2018, with the corresponding effect on depreciation expense immaterial when compared to the prior periods. In 2019 and 2020, all properties have sufficient reserves at current SEC prices which will enable equitable allocation of cost over the economic lives of the Upstream assets. The effect of this approach compared to prior periods is anticipated to be immaterial.

Investments in refinery and chemical process 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 on an ongoing basis whenever events or changes in circumstances indicate 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.

Asset valuation analysis, profitability reviews and other periodic control processes assist Imperial in assessing whether events or changes in circumstances indicate 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 believes prices over the long-term must be sufficient to generate investments in energy supply to meet global demand. Although prices will occasionally drop significantly, industry prices over the long-term will continue to be driven by market supply and demand fundamentals. On the supply side, industry production from mature fields is declining. This is being offset by investments to generate production from new discoveries, field developments and technological and efficiency advancements. OPEC investment activities and production policies also have an impact on world oil supplies. The demand side is largely a function of general economic activities and levels of prosperity. 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 development 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 to its long-term oil prices or natural gas prices or margin ranges, the company may consider that situation, in conjunction with other events or 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 yearly average of first-day-of-the-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.

The company has a robust process to monitor for indicators of potential impairment across its asset groups throughout the year. This process is aligned with the requirements of *ASC 360* and relies on the company's planning and budgeting cycle. If events or changes in circumstances indicate that the carrying value of an asset 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 assumptions of future capital allocations, crude oil and natural gas commodity prices, including price differentials, refining and chemical margins, volumes, development and operating costs, foreign currency exchange rates and inflation rates. Volumes are based on projected field and facility production profiles, throughput, or sales. Management's estimate of upstream production volumes used for projected cash flows makes use of proved reserve quantities and may include risk-adjusted unproved reserve quantities. Cash flow estimates for impairment testing exclude the effects of derivative instruments.

An asset group is impaired if its estimated future 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. 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 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.

Leases
In situations where assets are leased, right of use assets and lease liabilities are established on the balance sheet for leases with an expected term greater than one year, by discounting the amounts fixed in the lease agreement for the duration of the lease which is reasonably certain, considering the probability of exercising any early termination and extension options. The portion of the fixed payment related to service costs for tankers and finance leases is excluded from the calculation of right of use assets and lease liabilities. Assets leased for nearly all of their useful lives are accounted for as finance leases. In general, leases are capitalized using the company's incremental borrowing rate. See note 14 to the consolidated financial statements on page 90 for further details.

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 provisions 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.

Share-based compensation

The company awards share-based compensation to certain employees in the form of restricted stock units. Compensation expense is measured each reporting period based on the company's current stock price and is recorded as "Selling and general" expenses in the Consolidated statement of income over the requisite service period of each award. See note 8 to the consolidated financial statements on page 86 for further details.

Recently issued accounting standards

Effective January 1, 2020, Imperial adopted the Financial Accounting Standards Board’s update, *Financial Instruments - Credit Losses (Topic 326)*, as amended. The standard requires a valuation allowance for credit losses be recognized for certain financial assets that reflects the current expected credit loss over the asset’s contractual life. The valuation allowance considers the risk of loss, even if remote and considers past events, current conditions and expectations of the future. The January 1, 2020 estimated cumulative effect adjustment to “Earnings reinvested” related to implementation of the Credit Losses standard is expected to be de minimis.

2. Accounting changes

Effective January 1, 2019, Imperial adopted the Financial Accounting Standards Board’s standard, *Leases (Topic 842)*, as amended. The standard requires all leases to be recorded on the balance sheet as a right of use asset and a lease liability. The company used a transition method that applies the new lease standard at January 1, 2019. Imperial applied a policy election to exclude short-term leases from balance sheet recognition and also elected certain practical expedients at adoption. As permitted, the company did not reassess whether existing contracts are or contain leases, the lease classification for any existing leases, initial direct costs for any existing lease and whether existing land easements and rights of way, which were not previously accounted for as leases, are or contain a lease. At adoption on January 1, 2019, an operating lease liability of $298 million was recorded and the operating lease right of use asset was $298 million. There was no cumulative earnings effect adjustment.

3. Business segments

The company operates its business in Canada. The Upstream, Downstream and Chemical functions best define the operating segments of the business that are reported separately. The factors used to identify these reportable segments are based on the nature of the operations that are undertaken by each segment and the structure of the company's internal organization. The Upstream segment is organized and operates to explore for and ultimately produce crude oil and its equivalent, and natural gas. The Downstream segment is organized and operates to refine crude oil into petroleum products and 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, pension and other postretirement benefit liabilities. Net earnings effects under Corporate and other activities primarily include debt-related financing, corporate governance costs, non-service pension and postretirement benefit costs, share-based incentive compensation expenses and interest income.

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 Corporate and other activities. 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.

millions of Canadian dollars	Upstream 2019	Upstream 2018	Upstream 2017	Downstream 2019	Downstream 2018	Downstream 2017	Chemical 2019	Chemical 2018	Chemical 2017
Revenues and other income									
Revenues (a)	**9,479**	8,525	7,302	**23,591**	25,200	20,714	**932**	1,239	1,109
Intersegment sales	**3,763**	2,634	2,264	**1,597**	1,542	1,155	**229**	279	262
Investment and other income (note 9)	**17**	11	16	**47**	95	269	**-**	-	-
	13,259	11,170	9,582	**25,235**	26,837	22,138	**1,161**	1,518	1,371
Expenses									
Exploration (b) (note 16)	**47**	19	183	**-**	-	-	**-**	-	-
Purchases of crude oil and products	**6,528**	5,833	4,526	**19,332**	19,326	16,543	**667**	831	751
Production and manufacturing (c)	**4,440**	4,305	3,913	**1,829**	1,606	1,576	**251**	210	209
Selling and general (c)	**-**	-	-	**774**	773	772	**86**	87	78
Federal excise tax and fuel charge	**-**	-	-	**1,808**	1,667	1,673	**-**	-	-
Depreciation and depletion (b) (d)	**1,374**	1,278	1,939	**186**	242	202	**16**	14	12
Non-service pension and postretirement benefit (c)	**-**	-	-	**-**	-	-	**-**	-	-
Financing (note 13)	**3**	1	13	**-**	2	-	**-**	-	-
Total expenses	**12,392**	11,436	10,574	**23,929**	23,616	20,766	**1,020**	1,142	1,050
Income (loss) before income taxes	**867**	(266)	(992)	**1,306**	3,221	1,372	**141**	376	321
Income tax expense (benefit) (e) (note 4)	**(481)**	(128)	(286)	**345**	855	332	**33**	101	86
Net income (loss)	**1,348**	(138)	(706)	**961**	2,366	1,040	**108**	275	235
Cash flows from (used in) operating activities	**2,423**	916	1,257	**1,965**	2,749	1,396	**172**	354	235
Capital and exploration expenditures (f)	**1,248**	991	416	**484**	383	200	**34**	25	17
Property, plant and equipment									
Cost	**47,050**	46,435	45,542	**6,123**	5,900	5,683	**954**	916	888
Accumulated depreciation and depletion	**(15,889)**	(15,050)	(13,844)	**(3,830)**	(3,763)	(3,594)	**(680)**	(662)	(644)
Net property, plant and equipment (g)	**31,161**	31,385	31,698	**2,293**	2,137	2,089	**274**	254	244
Total assets (h) (i)	**34,554**	34,829	35,044	**5,179**	5,119	4,890	**416**	438	399

millions of Canadian dollars	Corporate and other 2019	Corporate and other 2018	Corporate and other 2017	Eliminations 2019	Eliminations 2018	Eliminations 2017	Consolidated 2019	Consolidated 2018	Consolidated 2017
Revenues and other income									
Revenues (a)	**-**	-	-	**-**	-	-	**34,002**	34,964	29,125
Intersegment sales	**-**	-	-	**(5,589)**	(4,455)	(3,681)	**-**	-	-
Investment and other income (note 9)	**35**	29	14	**-**	-	-	**99**	135	299
	35	29	14	**(5,589)**	(4,455)	(3,681)	**34,101**	35,099	29,424
Expenses									
Exploration (b) (note 16)	**-**	-	-	**-**	-	-	**47**	19	183
Purchases of crude oil and products	**-**	-	-	**(5,581)**	(4,449)	(3,675)	**20,946**	21,541	18,145
Production and manufacturing (c)	**-**	-	-	**-**	-	-	**6,520**	6,121	5,698
Selling and general (c)	**48**	54	49	**(8)**	(6)	(6)	**900**	908	893
Federal excise tax and fuel charge	**-**	-	-	**-**	-	-	**1,808**	1,667	1,673
Depreciation and depletion (b) (d)	**22**	21	19	**-**	-	-	**1,598**	1,555	2,172
Non-service pension and postretirement benefit (c)	**143**	107	-	**-**	-	-	**143**	107	-
Financing (note 13)	**90**	105	65	**-**	-	-	**93**	108	78
Total expenses	**303**	287	133	**(5,589)**	(4,455)	(3,681)	**32,055**	32,026	28,842
Income (loss) before income taxes	**(268)**	(258)	(119)	**-**	-	-	**2,046**	3,073	582
Income tax expense (benefit) (e) (note 4)	**(51)**	(69)	(40)	**-**	-	-	**(154)**	759	92
Net income (loss)	**(217)**	(189)	(79)	**-**	-	-	**2,200**	2,314	490
Cash flows from (used in) operating activities	**(124)**	(116)	(125)	**(7)**	19	-	**4,429**	3,922	2,763
Capital and exploration expenditures (f)	**48**	28	38	**-**	-	-	**1,814**	1,427	671
Property, plant and equipment									
Cost	**741**	693	665	**-**	-	-	**54,868**	53,944	52,778
Accumulated depreciation and depletion	**(266)**	(244)	(223)	**-**	-	-	**(20,665)**	(19,719)	(18,305)
Net property, plant and equipment (g)	**475**	449	442	**-**	-	-	**34,203**	34,225	34,473
Total assets (h) (i)	**2,536**	1,548	1,703	**(498)**	(478)	(435)	**42,187**	41,456	41,601

(a) Includes export sales to the United States of $7,190 million (2018 - $6,661 million, 2017 - $4,392 million). Export sales to the United States were recorded in all operating segments, with the largest effects in the Upstream segment.
(b) The Upstream segment in 2017 includes non-cash impairment charges of $396 million, before tax, associated with the Horn River development and $379 million, before tax, associated with the Mackenzie gas project. The impairment charges are recognized in the lines “Exploration” and “Depreciation and depletion” on the Consolidated statement of income, and the “Accumulated depreciation and depletion” line of the Consolidated balance sheet.
(c) As part of the implementation of Accounting Standard Update, Compensation – Retirement Benefits (Topic 715), beginning January 1, 2018, Corporate and other includes all non-service pension and postretirement benefit expense. Prior to 2018, the majority of these costs were allocated to the operating segments.
(d) In 2018, the Downstream segment included a non-cash impairment charge of $46 million, before tax, associated with the Government of Ontario’s revocation of its cap and trade legislation.
(e) Segment results in 2019 include a largely non-cash favourable impact of $662 million associated with the Alberta corporate income tax rate decrease, with the largest impact in the Upstream segment.
(f) Capital and exploration expenditures (CAPEX) include exploration expenses, additions to property, plant and equipment, additions to finance leases, additional investments and acquisitions. CAPEX excludes the purchase of carbon emission credits.
(g) Includes property, plant and equipment under construction of $2,149 million (2018 - $1,553 million, 2017 - $1,047 million).
(h) Effective January 1, 2019, Imperial adopted the Financial Accounting Standards Board’s standard, *Leases (Topic 842)*, as amended. As at December 31, 2019, Total assets include operating lease right of use assets of $260 million. An election was made not to restate prior periods. See note 14 for additional details.
(i) In 2019, the company removed $570 million from Total assets and corresponding liabilities in the Downstream segment associated with the Government of Ontario’s revocation of its cap and trade legislation.

4. Income taxes

millions of Canadian dollars	**2019**	2018	2017
Current income tax expense (a)	**140**	(14)	(58)
Deferred income tax expense (a)	**(294)**	773	150
Total income tax expense (a)	**(154)**	759	92
Statutory corporate tax rate (percent)	**26.0**	26.9	26.9
Increase (decrease) resulting from:			
Disposals (b)	**(0.6)**	(0.3)	(5.3)
Enacted tax rate change (a)	**(31.9)**	-	0.9
Other (c)	**(1.0)**	(1.9)	(6.6)
Effective income tax rate	**(7.5)**	24.7	15.9

(a) On June 28, 2019 the Alberta government enacted a 4 percent decrease in the provincial tax rate, from 12 percent to 8 percent by 2022. On November 2, 2017 the British Columbia government enacted a 1 percent increase in the provincial tax rate from 11 percent to 12 percent.
(b) 2017 disposals were primarily associated with the sale of surplus property in Ontario.
(c) Other decreases in 2017 and 2018 were primarily related to 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	**2019**	2018	2017
Depreciation and amortization	**5,164**	5,726	5,564
Successful drilling and land acquisitions	**750**	856	762
Pension and benefits	**(469)**	(336)	(422)
Asset retirement obligation	**(336)**	(381)	(376)
Capitalized interest	**117**	121	118
LIFO inventory valuation	**(276)**	(107)	(318)
Tax loss carryforwards	**(141)**	(658)	(936)
Other	**(161)**	(150)	(196)
Net deferred income tax liabilities	**4,648**	5,071	4,196

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	**2019**	2018	2017
Balance as of January 1	**36**	78	106
Additions for prior years' tax positions	**1**	9	2
Reductions for prior years' tax positions	**-**	(2)	-
Reductions due to lapse of the statute of limitations	**-**	-	-
Settlements with tax authorities	**(2)**	(49)	(30)
Balance as of December 31	**35**	36	78

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 2019, 2018 and 2017 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 2015 to 2019 are subject to examination by the tax authorities. Tax filings from 2003 to 2014 have open objections and therefore are also subject to examination by the tax authorities. The Canada Revenue Agency has made certain adjustments to the company's filings. Management has evaluated these adjustments and is formally disputing those matters to which the company disagrees. Many of these outstanding matters will not be resolved until after 2020. 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 could 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.

5. Employee retirement benefits

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

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

The expense and obligations for both funded and unfunded benefits are determined in accordance with 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.

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

	Pension benefits		Other postretirement benefits	
	2019	2018	**2019**	2018
Assumptions used to determine benefit obligations at December 31 (percent)				
Discount rate	**3.10**	3.90	**3.10**	3.90
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	**8,359**	8,785	**582**	670
Current service cost	**228**	239	**16**	17
Interest cost	**324**	302	**20**	22
Actuarial loss (gain)	**1,053**	(498)	**99**	(101)
Amendments	**283**	-	**-**	-
Benefits paid (a)	**(461)**	(469)	**(24)**	(26)
Projected benefit obligation at December 31	**9,786**	8,359	**693**	582
Accumulated benefit obligation at December 31	**8,814**	7,661		

The discount rate for the purpose of calculating year-end postretirement benefits plan liabilities is determined by using the Canadian Institute of Actuaries recommended spot curve for high-quality, long-term Canadian corporate bonds with an average maturity (or duration) approximating that of the liabilities. For the measurement of the accumulated postretirement benefit obligation, the assumed health care cost trend rates start with 5.66 percent in 2020 and gradually decline to 3.57 percent by 2040 and beyond. A 1.0 percent increase in the health care cost trend rate would increase service and interest cost by $5 million and the accumulated postretirement benefit obligation by $75 million. A 1.0 percent decrease in the health care cost trend rate would decrease service and interest cost by $4 million and the accumulated postretirement benefit obligation by $60 million.

	Pension benefits		Other postretirement benefits	
millions of Canadian dollars	**2019**	2018	**2019**	2018
Change in plan assets				
Fair value at January 1	**7,691**	7,870		
Actual return (loss) on plan assets	**1,114**	20		
Company contributions	**211**	203		
Benefits paid (b)	**(417)**	(402)		
Fair value at December 31	**8,599**	7,691		
Plan assets in excess of (less than) projected benefit obligation at December 31				
Funded plans	**(590)**	(180)		
Unfunded plans	**(597)**	(488)	**(693)**	(582)
Total (c)	**(1,187)**	(668)	**(693)**	(582)

(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 postretirement benefits plans, the underfunded status of the company’s defined benefit postretirement plans was recorded as a liability in the Consolidated balance sheet, and the changes in that funded status in the year in which the changes occurred was recognized through other comprehensive income.

millions of Canadian dollars	Pension benefits 2019	2018	Other postretirement benefits 2019	2018
Amounts recorded in the Consolidated balance sheet consist of:				
Current liabilities	**(27)**	(27)	**(31)**	(28)
Other long-term obligations	**(1,160)**	(641)	**(662)**	(554)
Total recorded	**(1,187)**	(668)	**(693)**	(582)
Amounts recorded in accumulated other comprehensive income consist of:				
Net actuarial loss (gain)	**2,256**	2,117	**133**	33
Prior service cost	**283**	-	**-**	-
Total recorded in accumulated other comprehensive income, before tax	**2,539**	2,117	**133**	33

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 2019 long-term expected return of 4.5 percent used in the calculations of pension expense compares to an actual rate of return of 8.1 percent and 6.6 percent over the last 10- and 20-year periods respectively, ending December 31, 2019.

	Pension benefits 2019	2018	2017	Other postretirement benefits 2019	2018	2017
Assumptions used to determine net periodic benefit cost for years ended December 31 (percent)						
Discount rate	**3.90**	3.40	3.75	**3.90**	3.40	3.75
Long-term rate of return on funded assets	**4.50**	5.00	5.50	**-**	-	-
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	**228**	239	217	**16**	17	16
Interest cost	**324**	302	313	**20**	22	23
Expected return on plan assets	**(349)**	(402)	(408)	**-**	-	-
Amortization of prior service cost	**-**	4	10	**-**	-	-
Amortization of actuarial loss (gain)	**149**	175	176	**(1)**	6	8
Net periodic benefit cost	**352**	318	308	**35**	45	47
Changes in amounts recorded in accumulated other comprehensive income						
Net actuarial loss (gain)	**288**	(116)	123	**99**	(101)	(49)
Amortization of net actuarial (loss) gain included in net periodic benefit cost	**(149)**	(175)	(176)	**1**	(6)	(8)
Prior service cost	**283**	-	-	**-**	-	-
Amortization of prior service cost included in net periodic benefit cost	**-**	(4)	(10)	**-**	-	-
Total recorded in other comprehensive income	**422**	(295)	(63)	**100**	(107)	(57)
Total recorded in net periodic benefit cost and other comprehensive income, before tax	**774**	23	245	**135**	(62)	(10)

Costs for defined contribution plans, primarily the employee savings plan, were $43 million in 2019 (2018 - $41 million, 2017 - $40 million).

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

millions of Canadian dollars	Total pension and other postretirement benefits 2019	2018	2017
(Charge) credit to other comprehensive income, before tax	**(522)**	402	120
Deferred income tax (charge) credit (note 18)	**128**	(104)	(38)
(Charge) credit to other comprehensive income, after tax	**(394)**	298	82

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 30 percent. The target allocation for debt securities is 67 percent. Plan assets for the remaining 3 percent are invested in venture capital partnerships that pursue a strategy of investment in U.S. and international early stage ventures.

The 2019 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, 2019, using:			
millions of Canadian dollars	Total	Level 1	Level 2	Level 3	Net Asset Value
Asset class					
Equity securities					
Canadian	**210**				**210**
Non-Canadian	**2,449**				**2,449**
Debt securities - Canadian					
Corporate	**1,379**				**1,379**
Government	**4,299**				**4,299**
Asset backed	**1**				**1**
Equities – Venture capital	**204**				**204**
Cash	**57**	**40**			**17**
Total plan assets at fair value	**8,599**	**40**			**8,559**

The 2018 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, 2018, using:			
millions of Canadian dollars	Total	Level 1	Level 2	Level 3	Net Asset Value
Asset class					
Equity securities					
Canadian	170				170
Non-Canadian	2,035				2,035
Debt securities - Canadian					
Corporate	1,231				1,231
Government	3,987				3,987
Asset backed	3				3
Equities – Venture capital	226				226
Cash	39	33			6
Total plan assets at fair value	7,691	33	-	-	7,658

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	**2019**	2018
For funded pension plans with accumulated benefit obligations in excess of plan assets: (a)		
Projected benefit obligation	**1,042**	943
Accumulated benefit obligation	**942**	852
Fair value of plan assets	**870**	739
Accumulated benefit obligation less fair value of plan assets	**72**	113
For unfunded plans covered by book reserves:		
Projected benefit obligation	**597**	488
Accumulated benefit obligation	**536**	451

(a) The amounts shown for funded pension plans with accumulated benefit obligations in excess of plan assets represent the company's proportionate share of a joint venture sponsored pension plan. For the company sponsored funded plan, plan assets exceeded the accumulated benefit obligation in both 2019 and 2018.

Estimated 2020 amortization from accumulated other comprehensive income

millions of Canadian dollars	Pension benefits	Other postretirement benefits
Net actuarial loss (gain) (a)	**157**	**9**
Prior service cost (b)	**13**	**-**

(a) The company amortizes the net balance of actuarial loss (gain) as a component of net periodic benefit cost over the average remaining service period of active plan participants.

(b) The company amortizes prior service cost on a straight-line basis.

Cash flows

Benefit payments expected in:

millions of Canadian dollars	Pension benefits	Other postretirement benefits
2020	**460**	**31**
2021	**460**	**31**
2022	**460**	**32**
2023	**460**	**32**
2024	**460**	**32**
2025 - 2029	**2,245**	**160**

In 2020, the company expects to make cash contributions of about $216 million to its pension plans.

6. Other long-term obligations

millions of Canadian dollars	**2019**	2018
Employee retirement benefits (a) (note 5)	**1,822**	1,195
Asset retirement obligations and other environmental liabilities (b) (d)	**1,388**	1,435
Share-based incentive compensation liabilities (note 8)	**65**	78
Operating lease liability (c) (note 14)	**143**	-
Other obligations	**219**	235
Total other long-term obligations	**3,637**	2,943

(a) Total recorded employee retirement benefits obligations also included $58 million in current liabilities (2018 – $55 million).

(b) Total asset retirement obligations and other environmental liabilities also included $124 million in current liabilities (2018 – $118 million).

(c) Effective January 1, 2019, Imperial adopted the Financial Accounting Standards Board's standard, *Leases (Topic 842)*, as amended. The standard requires all leases to be recorded on the balance sheet as a right of use asset and liability. The long-term lease liability for operating leases is included in Other long-term obligations (see note 14).

(d) For 2019, the asset retirement obligations were discounted at 6 percent (2018 - 6 percent).
Asset retirement obligations incurred in the current period were Level 3 fair value measurements. The following table summarizes the activity in the liability for asset retirement obligations:

millions of Canadian dollars	**2019**	2018
Balance as at January 1	**1,417**	1,397
Additions (deductions)	**(23)**	(5)
Accretion	**80**	85
Settlement	**(74)**	(60)
Balance as at December 31	**1,400**	1,417

7. Financial and derivative instruments

Financial instruments
The fair value of the company's financial instruments is determined by reference to various market data and other appropriate valuation techniques. There are no material differences between the fair value of the company's financial instruments and the recorded carrying value. At December 31, 2019 and at December 31, 2018, the fair value of long-term debt ($4,447 million, excluding finance lease obligations) was primarily a level 2 measurement.

Derivative instruments
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 exchange rates. In addition, the company uses commodity-based contracts, including derivative instruments to manage commodity price risk. The company does not designate derivative instruments as a hedge for hedge accounting purposes.

Credit risk associated with the company's derivative position is mitigated by several factors, including the use of derivative clearing exchanges and the quality of and financial limits placed on derivative counterparties. The company maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity.

The carrying values of derivative instruments on the Consolidated balance sheet were gross assets of $0 million (2018- $31 million), gross liabilities of $2 million (2018- $15 million) and collateral receivable of $6 million (2018- $0 million) at year end.

At December 31, 2019, the net notional forward long / (short) position of derivative instruments was (590,000) barrels for crude and 0 barrels for products. At December 31, 2018, the net notional forward long / (short) position of derivative instruments was (340,000) barrels for crude and (350,000) barrels for products.

Realized and unrealized gain or (loss) on derivative instruments recognized in the Consolidated statement of income is included in the following lines on a before-tax basis:

millions of Canadian dollars	**2019**	2018	2017
Revenues	**(3)**	6	-
Purchases of crude oil and products	**(7)**	(24)	(5)
Total	**(10)**	(18)	(5)

8. Share-based incentive compensation programs

Share-based incentive compensation programs are designed to retain selected employees, reward them for high performance and promote individual contribution to sustained improvement in the company's future business performance and shareholder value over the long-term. The nonemployee directors also participate in share-based incentive compensation programs.

Restricted stock units and deferred share units
Under the restricted stock unit plan, each unit entitles the recipient to the conditional right to receive from the company, upon vesting, an amount equal to the value of one common share of the company, based on the five-day average of the closing price of the company's common shares on the Toronto Stock Exchange on and immediately prior to the vesting dates. Fifty percent of the units vest on the third anniversary of the grant date, and the remainder vest on the seventh anniversary of the grant date. The company may also issue units where either 50 percent of the units vest on the fifth anniversary of the grant date and the remainder vest on the tenth anniversary of the grant date, or where 50 percent of the units vest on the fifth anniversary of the grant date and the remainder vest on the tenth anniversary of the grant date, or date of retirement of the recipient, whichever is later.

The deferred share unit plan is made available to nonemployee directors. The nonemployee directors can elect to receive all or part of their eligible directors' fees in units. The number of units granted is determined at the end of each calendar quarter by dividing the dollar amount of the nonemployee director's fees for that calendar quarter elected to be received as deferred share units by the average closing price of the company's shares for the five consecutive trading days ("average closing price") immediately prior to the last day of the calendar quarter. Additional units are granted to represent dividends on unexercised units, and are calculated by dividing the cash dividend payable on the company's shares by the average closing price immediately prior to the payment date for that dividend and multiplying the resulting number by the number of deferred share units held by the recipient, as adjusted for any share splits. Deferred share units cannot be exercised until after termination of service as a director, including termination due to death, and must be exercised in their entirety in one election no later than December 31 of the year following the year of termination of service. On the exercise date, the cash value to be received for the units is determined based on the company's average closing price immediately prior to the date of exercise, as adjusted for any share splits.

All units require settlement by cash payments with the following exceptions. The restricted stock unit program provides that, for units granted to Canadian residents, the recipient may receive one common share of the company per unit or elect to receive the cash payment for the units that vest on the seventh year anniversary of the grant date. For units where 50 percent vest on the fifth anniversary of the grant date and the remainder vest on either the tenth anniversary of grant, or the later of ten years following the grant date or the retirement date of the recipient, the recipient may receive one common share of the company per unit or elect to receive cash payment for all that vest.

The company accounts for all units by using the fair-value-based method. The fair value of awards in the form of restricted stock and deferred share units is the market price of the company's stock. Under this method, compensation expense related to the units of these programs is measured each reporting period based on the company's current stock price and is recorded in the Consolidated statement of income over the requisite service period of each award.

The following table summarizes information about these units for the year ended December 31, 2019:

	Restricted stock units	Deferred share units
Outstanding at January 1, 2019	**5,302,825**	**151,695**
Granted	**854,800**	**18,468**
Vested / Exercised	**(1,241,280)**	**-**
Forfeited and cancelled	**(3,540)**	**-**
Outstanding at December 31, 2019	**4,912,805**	**170,163**

In 2019, the before-tax compensation expense charged against income for these programs was $34 million (2018 - $32 million, 2017 - $14 million). Income tax benefit recognized in income related to compensation expense for the year was $9 million (2018- $9 million, 2017 - $4 million). Cash payments of $50 million were made for these programs in 2019 (2018- $59 million, 2017 - $71 million).

As of December 31, 2019, there was $76 million of total before-tax unrecognized compensation expense related to non-vested restricted stock units based on the company's share price at the end of the current reporting period. The weighted average vesting period of non-vested restricted stock units is 4.1 years. All units under the deferred share programs have vested as of December 31, 2019.

9. Investment and other income

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

millions of Canadian dollars	**2019**	2018	2017
Proceeds from asset sales	**82**	59	232
Book value of asset sales	**36**	5	12
Gain (loss) on asset sales, before-tax (a)	**46**	54	220
Gain (loss) on asset sales, after-tax (a)	**42**	38	192

(a) 2017 included a gain of $174 million ($151 million after tax) from the sale of surplus property in Ontario.

10. Litigation and other contingencies

A variety of claims have been made against Imperial and its subsidiaries in a number of lawsuits. Management has regular litigation reviews, including updates from corporate and outside counsel, to assess the need for accounting recognition or disclosure of these contingencies. The company accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The company does not record liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavourable outcome is reasonably possible and which are significant, the company discloses the nature of the contingency and, where feasible, an estimate of the possible loss. For purposes of the company’s contingency disclosures, “significant” includes material matters, as well as other matters which management believes should be disclosed. Based on a consideration of all relevant facts and circumstances, the company does not believe the ultimate outcome of any currently pending lawsuits against the company will have a material adverse effect on the company's operations, financial condition, or financial statements taken as a whole.

Additionally, the company has other commitments arising in the normal course of business for operating and capital needs, all of which are expected to be fulfilled with no adverse consequences material to the company's operations or financial condition. Unconditional purchase obligations, as defined by accounting standards, are those long-term commitments that are non-cancelable or cancelable only under certain conditions and that third parties have used to secure financing for the facilities that will provide the contracted goods and services. The company has not entered into any unconditional purchase obligations.

As a result of the completed sale of Imperial’s remaining company-owned Esso retail sites, the company was contingently liable at December 31, 2019, for guarantees relating to performance under contracts of other third-party obligations totalling $30 million (2018 - $35 million).

At December 31, 2019 the company is contingently liable for up to $64 million, under existing indemnification arrangements, for costs associated with continuing a third party pipeline project development (2018 - $46 million).

11. Common shares

thousands of shares At December 31	**2019**	2018
Authorized	**1,100,000**	1,100,000
Common shares outstanding	**743,902**	782,565

The current 12-month normal course issuer bid program came into effect June 27, 2019, under which Imperial will continue its existing share purchase program. The program enables the company to purchase up to a maximum of 38,211,086 common shares (5 percent of the total shares on June 13, 2019) which includes shares purchased under the normal course issuer bid and from Exxon Mobil Corporation concurrent with, but outside of the normal course issuer bid. As in the past, Exxon Mobil Corporation has advised the company that it intends to participate to maintain its ownership percentage at approximately 69.6 percent.

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

The company's common share activities are summarized below:

	Thousands of shares	Millions of dollars
Balance as at January 1, 2017	847,599	1,566
Issued under employee share-based awards	2	-
Purchases at stated value	(16,359)	(30)
Balance as at December 31, 2017	831,242	1,536
Issued under employee share-based awards	2	-
Purchases at stated value	(48,679)	(90)
Balance as at December 31, 2018	782,565	1,446
Issued under employee share-based awards	1	-
Purchases at stated value	(38,664)	(71)
Balance as at December 31, 2019	**743,902**	**1,375**

The following table provides the calculation of basic and diluted earnings per common share and the dividends declared by the company on its outstanding common shares:

	2019	2018	2017
Net income (loss) per common share – basic			
Net income (loss) (millions of Canadian dollars)	**2,200**	2,314	490
Weighted average number of common shares outstanding (millions of shares)	**762.7**	807.5	842.9
Net income (loss) per common share (dollars)	**2.88**	2.87	0.58
Net income (loss) per common share – diluted			
Net income (loss) (millions of Canadian dollars)	**2,200**	2,314	490
Weighted average number of common shares outstanding (millions of shares)	**762.7**	807.5	842.9
Effect of employee share-based awards (millions of shares)	**2.3**	2.6	2.8
Weighted average number of common shares outstanding, assuming dilution (millions of shares)	**765.0**	810.1	845.7
Net income (loss) per common share (dollars)	**2.88**	2.86	0.58
Dividends per common share – declared (dollars)	**0.85**	0.73	0.63

12. Miscellaneous financial information

In 2019, net income included an after-tax loss of $22 million (2018 – $16 million gain, 2017 – $5 million gain) attributable to the effect of changes in last-in, first-out (LIFO) inventories. The replacement cost of inventories was estimated to exceed their LIFO carrying values at December 31, 2019 by about $1.2 billion (2018 – $0.9 billion). Inventories of crude oil and products at year-end consisted of the following:

millions of Canadian dollars	**2019**	2018
Crude oil	**764**	731
Petroleum products	**396**	473
Chemical products	**64**	72
Other	**72**	21
Total inventories of crude oil and products	**1,296**	1,297

Research expenditures are mainly spent on developing technologies to improve bitumen recovery, reduce costs and reduce the environmental impact of upstream operations, including technologies to reduce greenhouse gas emissions intensity, 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 licencing 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.

Net research and development costs charged to expenses in 2019 were $133 million (2018 – $110 million, 2017 – $111 million). These costs are included in expenses due to the uncertainty of future benefits.

Accounts payable and accrued liabilities included accrued taxes other than income taxes of $397 million at December 31, 2019 (2018 – $413 million).

13. Financing and additional notes and loans payable information

millions of Canadian dollars	**2019**	2018	2017
Debt-related interest (a)	**138**	133	103
Capitalized interest	**(48)**	(28)	(38)
Net interest expense	**90**	105	65
Other interest	**3**	3	13
Total financing (b)	**93**	108	78

(a) Includes related party interest with ExxonMobil.

(b) The weighted average interest rate on short-term borrowings in 2019 was 1.8 percent (2018 – 1.5 percent, 2017– 0.9 percent). Average effective rate on the long-term borrowings with ExxonMobil in 2019 was 2.2 percent (2018 – 2.0 percent, 2017 – 1.3 percent).

In November 2019, the company increased the capacity of its non-interest bearing, revolving demand loan with ExxonMobil from $75 million to $150 million. The loan represents ExxonMobil's share of a working capital facility required to support purchasing, marketing, transportation and derivative arrangements for crude oil and diluent products undertaken by Imperial on behalf of ExxonMobil. At December 31, 2019 the company had borrowed $111 million under this arrangement.

In November 2019, the company extended the maturity date of its existing $250 million committed long-term line of credit to November 2021. The company has not drawn on the facility.

In December 2019, the company extended the maturity date of its existing $250 million committed short-term line of credit to December 2020. The company has not drawn on the facility.

14. Leases

The company generally purchases the property, plant and equipment used in operations, but there are situations where assets are leased, primarily storage tanks, rail cars, marine vessels and transportation facilities. Right of use assets and lease liabilities are established on the balance sheet for leases with an expected term greater than one year, by discounting the amounts fixed in the lease agreement for the duration of the lease which is reasonably certain, considering the probability of exercising any early termination and extension options. The portion of the fixed payment related to service costs for tankers and finance leases is excluded from the calculation of right of use assets and lease liabilities. Usually, assets are leased only for a portion of their useful lives and are accounted for as operating leases. In limited situations assets are leased for nearly all of their useful lives and are accounted for as finance leases. In general, leases are capitalized using the company's incremental borrowing rate.

Variable payments under these lease agreements are not significant. Residual value guarantees, restrictions, or covenants related to leases, and transactions with related parties are also not significant. The company's activities as a lessor are not material.

At adoption of the lease accounting change (see note 2), on January 1, 2019, an operating lease liability of $298 million was recorded and the operating lease right of use asset was $298 million. There was no cumulative earnings effect adjustment.

The table below summarizes the total lease cost incurred:

	2019	
millions of Canadian dollars	Operating leases	Finance leases
Operating lease cost	151	
Short-term and other (net of sublease rental income)	76	
Amortization of right of use assets		55
Interest on lease liabilities		40
Total lease cost	227	95

The following table summarizes the amounts related to operating leases and finance leases recorded on the Consolidated balance sheet as at December 31, 2019:

	2019	
millions of Canadian dollars	Operating leases	Finance leases
Right of use assets		
Included in Other assets, including intangibles, net	260	
Included in Property, plant and equipment, net		546
Total right of use assets	260	546
Lease liability due within one year		
Included in Accounts payable and accrued liabilities	115	15
Included in Notes and loans payable		18
Long-term lease liability		
Included in Other long-term obligations	143	-
Included in Long-term debt		514
Total lease liability	258	547

The maturity analysis of the company's lease liabilities, weighted average remaining lease term and weighted average discount rates applied at December 31, 2019, are summarized below:

	2019	
millions of Canadian dollars, unless noted	Operating leases	Finance leases
Maturity analysis of lease liabilities		
2020	121	71
2021	70	50
2022	30	49
2023	13	48
2024	11	47
2025 and beyond	30	1,086
Total lease payments	275	1,351
Discount to present value	(17)	(804)
Total lease liability	258	547
Weighted average remaining lease term (years)	4	40
Weighted average discount rate (percent)	2.6	7.5

In addition to the operating lease liabilities in the table immediately above, at December 31, 2019, additional undiscounted commitments for leases not yet commenced totalled $6 million.

The table below summarizes the cash paid for amounts included in the measurement of lease liabilities and the right of use assets obtained in exchange for new lease liabilities:

	2019	
millions of Canadian dollars	Operating leases	Finance leases
Cash paid for amounts included in the measurement of lease liabilities		
Cash flows from operating activities	147	45
Cash flows from financing activities		27
Non-cash right of use assets recorded for lease liabilities		
For January 1 adoption of *Leases (Topic 842)*	298	
In exchange for new lease liabilities during the year	104	

Disclosures under the previous lease standard *(Topic 840)*

Net rental cost incurred under both cancelable and non-cancelable operating leases was $221 million in 2018 and $206 million in 2017. At December 31, 2018, minimum undiscounted lease commitments under non-cancelable operating leases for 2019 and beyond were $291 million.

15. Long-term debt

millions of Canadian dollars At December 31	2019	2018
Long-term debt (a)	**4,447**	4,447
Finance leases (b)	**514**	531
Total long-term debt	**4,961**	4,978

(a) Borrowed under an existing agreement with an affiliated company of ExxonMobil that provides for a long-term, variable-rate, Canadian dollar loan from ExxonMobil to the company of up to $7.75 billion at interest equivalent to Canadian market rates. The agreement is effective until June 30, 2025, cancelable if ExxonMobil provides at least 370 days advance written notice.

(b) Finance leases are primarily associated with transportation facilities and services agreements. The average imputed rate was 7.5 percent in 2019 (2018 – 7.1 percent). Total finance lease obligations also include $18 million in current liabilities (2018 - $27 million). Principal payments on finance leases of approximately $13 million on average per year are due in each of the next four years after December 31, 2020.

In September 2019, the company extended the maturity date of its existing long-term, variable-rate, Canadian dollar loan from ExxonMobil to June 30, 2025. All other terms and conditions remain unchanged.

16. Accounting for 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. 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.

Exploratory well costs that were capitalized in prior years as part of the Horn River project for a period greater than one year were expensed in 2017.

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

Change in capitalized suspended exploratory well costs:

millions of Canadian dollars	**2019**	2018	2017
Balance as at January 1	**-**	-	143
Additions pending the determination of proved reserves	**-**	-	-
Charged to expense	**-**	-	(143)
Reclassification to wells, facilities and equipment based on the determination of proved reserves	**-**	-	-
Balance as at December 31	**-**	-	-

Period end capitalized suspended exploratory well costs:

millions of Canadian dollars	**2019**	2018	2017
Capitalized for a period of one year or less	**-**	-	-
Capitalized for a period of between one and ten years	**-**	-	-
Capitalized for a period of greater than one year	**-**	-	-
Total	**-**	-	-

Exploration activity often involves drilling multiple wells, over a number of years, to fully evaluate a project. The table below provides a breakdown of the number of projects with only exploratory well costs capitalized for a period of one year or less and those that have had exploratory well costs capitalized for a period greater than one year.

	2019	2018	2017
Number of projects that only have exploratory well costs capitalized for a period of one year or less	**-**	-	-
Number of projects that have exploratory well costs capitalized for a period of greater than one year	**-**	-	-
Total	**-**	-	-

17. Transactions with related parties

Revenues and expenses of the company also include the results of transactions with affiliated companies of ExxonMobil in the normal course of operations. These were conducted on terms comparable to those which would have been conducted with unrelated parties and primarily consisted of the purchase and sale of crude oil, natural gas, petroleum and chemical products, as well as technical, engineering and research, and development costs. Transactions with ExxonMobil also included amounts paid and received in connection with the company's participation in a number of upstream activities conducted jointly in Canada.

In addition, the company has existing agreements with ExxonMobil:

a) To provide computer and customer support services to the company and to share common business and operational support services that allow the companies to consolidate duplicate work and systems;

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

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

d) To provide for the option of equal participation in new upstream opportunities; and

e) To enter into derivative agreements on each other's behalf.

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

The amounts of purchases and sales by Imperial in 2019, with ExxonMobil, were $3,245 million and $8,552 million respectively (2018 - $4,036 million and $6,364 million respectively).

As at December 31, 2019, the company had outstanding long-term loans of $4,447 million (2018 – $4,447 million) and short-term loans of $111 million (2018 – $75 million) from ExxonMobil (see note 15, Long-term debt, on page 92 and note 13, Financing and additional notes and loans payable information, on page 89 for further details). The amount of financing costs with ExxonMobil were $96 million (2018 - $87 million).

Imperial has other related party transactions not detailed above in note 17, as they are not significant.

18. Other comprehensive income (loss) information

Changes in accumulated other comprehensive income (loss):

millions of Canadian dollars	**2019**	2018	2017
Balance at January 1	**(1,517)**	(1,815)	(1,897)
Postretirement benefits liability adjustment:			
Current period change excluding amounts reclassified from accumulated other comprehensive income	**(505)**	158	(54)
Amounts reclassified from accumulated other comprehensive income	**111**	140	136
Balance at December 31	**(1,911)**	(1,517)	(1,815)

Amounts reclassified out of accumulated other comprehensive income (loss) - before-tax income (expense):

millions of Canadian dollars	**2019**	2018	2017
Amortization of postretirement benefits liability adjustment included in net periodic benefit cost (a)	**(148)**	(185)	(194)

(a) This accumulated other comprehensive income component is included in the computation of net periodic benefit cost (note 5).

Income tax expense (credit) for components of other comprehensive income (loss):

millions of Canadian dollars	**2019**	2018	2017
Postretirement benefits liability adjustments:			
Postretirement benefits liability adjustment (excluding amortization)	**(165)**	59	(20)
Amortization of postretirement benefits liability adjustment included in net periodic benefit cost	**37**	45	58
Total	**(128)**	104	38

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

The information on pages 96 to 97 excludes items not related to oil and natural gas extraction, such as administrative and general expenses, pipeline operations, gas plant processing fees and gains or losses on asset sales. The company's 25 percent interest in proved synthetic oil reserves in the Syncrude joint-venture is included as part of the company's total proved oil and gas reserves and in the calculation of the standardized measure of discounted future cash flows, in accordance with U.S. Securities and Exchange Commission and U.S. Financial Accounting Standards Board rules. Results of operations, costs incurred in property acquisitions, exploration and development activities, and capitalized costs include the company's share of Kearl, Syncrude and other unproved mineable acreages in the following tables.

Results of operations

millions of Canadian dollars	**2019**	2018	2017
Sales to customers (a)	**3,927**	3,264	3,283
Intersegment sales (a) (b)	**2,627**	1,964	1,750
	6,554	5,228	5,033
Production expenses	**4,467**	4,342	3,959
Exploration expenses	**47**	19	183
Depreciation and depletion	**1,266**	1,151	1,623
Income taxes	**(487)**	(92)	(217)
Results of operations	**1,261**	(192)	(515)

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

Costs incurred in property acquisitions, exploration and development activities

millions of Canadian dollars	**2019**	2018	2017
Property costs (c)			
Proved	**-**	-	-
Unproved	**2**	-	32
Exploration costs	**47**	19	40
Development costs	**1,176**	966	214
Total costs incurred in property acquisitions, exploration and development activities	**1,225**	985	286

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

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

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

Capitalized costs

millions of Canadian dollars	**2019**	2018
Property costs (a)		
Proved	**2,236**	2,296
Unproved	**2,342**	2,372
Producing assets	**38,975**	38,695
Incomplete construction	**1,640**	1,214
Total capitalized cost	**45,193**	44,577
Accumulated depreciation and depletion	**(15,695)**	(14,897)
Net capitalized costs	**29,498**	29,680

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

Standardized measure of discounted future cash flows

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

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

millions of Canadian dollars	**2019**	2018	2017
Future cash flows	**166,801**	174,326	72,325
Future production costs	**(127,911)**	(124,316)	(44,822)
Future development costs	**(24,759)**	(25,507)	(14,640)
Future income taxes	**(3,960)**	(5,232)	(3,916)
Future net cash flows	**10,171**	19,271	8,947
Annual discount of 10 percent for estimated timing of cash flows	**(4,660)**	(10,537)	(3,811)
Discounted future cash flows	**5,511**	8,734	5,136

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

millions of Canadian dollars	**2019**	2018	2017
Balance at beginning of year	**8,734**	5,136	2,746
Changes resulting from:			
Sales and transfers of oil and gas produced, net of production costs	**(2,441)**	(1,117)	(1,516)
Net changes in prices, development costs and production costs (a)	**(3,117)**	1,395	4,231
Extensions, discoveries, additions and improved recovery, less related costs	**169**	259	81
Development costs incurred during the year	**1,016**	923	376
Revisions of previous quantity estimates	**(168)**	2,157	110
Accretion of discount	**643**	584	290
Net change in income taxes	**675**	(603)	(1,182)
Net change	**(3,223)**	3,598	2,390
Balance at end of year	**5,511**	8,734	5,136

(a) SEC rules require the company's reserves to be calculated on the basis of average first-day-of-the-month oil and natural gas prices during the reporting year. Future net cash flows are determined based on the net proved reserves as outlined in the Net Proved Reserves table.

Net proved reserves (a)

	Liquids (b)	Natural gas	Synthetic oil	Bitumen	Total oil-equivalent basis (c)
	millions of barrels	billions of cubic feet	millions of barrels	millions of barrels	millions of barrels
Beginning of year 2017	35	495	564	701	1,382
Revisions	4	115	(70)	332	286
Improved recovery	-	1	-	6	6
(Sale) purchase of reserves in place	4	28	-	-	9
Discoveries and extensions	2	43	-	-	9
Production	(1)	(41)	(21)	(93)	(122)
End of year 2017	44	641	473	946	1,570
Revisions	4	(66)	15	2,313	2,321
Improved recovery	-	-	-	-	-
(Sale) purchase of reserves in place	-	-	-	-	-
Discoveries and extensions	16	110	-	-	34
Production	(2)	(46)	(22)	(93)	(125)
End of year 2018	62	639	466	3,166	3,800
Revisions	(20)	(33)	(27)	(134)	(187)
Improved recovery	-	-	-	-	-
(Sale) purchase of reserves in place	-	(24)	-	-	(4)
Discoveries and extensions	4	51	-	-	13
Production	(5)	(52)	(24)	(93)	(130)
End of year 2019	**41**	**581**	**415**	**2,939**	**3,492**
Net proved developed reserves included above, as of					
January 1, 2017	19	263	564	436	1,063
December 31, 2017	9	282	473	591	1,120
December 31, 2018	24	273	466	2,861	3,396
December 31, 2019	**22**	**291**	**415**	**2,609**	**3,095**
Net proved undeveloped reserves included above, as of					
January 1, 2017	16	232	-	265	319
December 31, 2017	35	359	-	355	450
December 31, 2018	38	366	-	305	404
December 31, 2019	**19**	**290**	**-**	**330**	**397**

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

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

(c) Gas converted to oil-equivalent at six million cubic feet per one thousand barrels.

The information above describes changes during the years and balances of proved oil and gas reserves at year-end 2017, 2018 and 2019. The definitions used are in accordance with the U.S. Securities and Exchange Commission's Rule 4-10 (a) of Regulation S-X.

Proved oil and natural gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations – prior to the time at which contracts providing the right to operate expire. In some cases, substantial new investments in additional wells and other facilities will be required to recover these proved reserves.

In accordance with SEC rules, the year-end reserves volumes, as well as the reserves change categories shown in the proved reserves tables are required to be calculated on the basis of average prices during the

12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period. These reserves quantities were also used in calculating unit-of-production depreciation rates and in calculating the standardized measure of discounted net cash flow.

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-day-of-the-month oil and natural gas prices and / or costs that are used in the estimation of reserves. Revisions can result from significant changes in either development strategy or production equipment / facility capacity.

At year-end 2016, downward revisions of proved developed and undeveloped bitumen reserves were a result of low prices. The entire 2.5 billion barrels of bitumen at Kearl and approximately 0.2 billion barrels of bitumen at Cold Lake no longer qualified as proved reserves under the U.S. Securities and Exchange Commission definition of proved reserves.

At year-end 2017, an additional 0.3 billion barrels of bitumen at Kearl and Cold Lake qualified as proved reserves resulting from improved prices in the year. Downward revisions of proved developed synthetic oil reserves were a result of higher royalty obligations driven by higher pricing and mine plan updates.

As a result of improved prices in 2018, an additional 2.3 billion barrels of bitumen at Kearl qualified as proved reserves at year-end 2018.

In 2019, downward revisions to proved bitumen reserves were driven by technical and development plan updates at Kearl, resulting in a decrease of 0.2 billion barrels, partially offset by an increase of 0.1 billion barrels at Cold Lake associated with an end of field life change driven by pricing. Downward revisions to proved synthetic oil reserves were a result of higher royalty obligations at Syncrude driven by pricing. Changes to liquids and natural gas proved reserves were the result of updated development plans at the Montney and Duvernay unconventional assets and the divestment of conventional properties.

Under the terms of certain contractual arrangements or government royalty regimes, lower prices can also increase proved reserves attributable to Imperial. The company's operating decisions and its outlook for future production volumes are not impacted by proved reserves as disclosed under the U.S. Securities and Exchange Commission (SEC) definition.

Net proved reserves are determined by deducting the estimated future share of mineral owners or governments or both. For liquids and natural gas, net proved reserves are based on estimated future royalty rates as of the date the estimate is made incorporating the applicable governments’ oil and gas royalty regimes. For bitumen, net proved reserves are based on the company’s best estimate of average royalty rates over the remaining life of each of the Cold Lake and Kearl fields, and they incorporate the Alberta government's oil sands royalty regime. For synthetic oil, net proved reserves are based on the company’s best estimate of average royalty rates over the remaining life of the project, and they incorporate the Alberta government’s oil sands royalty regime. In all cases, actual future royalty rates may vary with production, price and costs.

Net proved developed reserves are those volumes that are expected to be recovered through existing wells and facilities with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well or facility. Net proved undeveloped reserves are those volumes that are expected to be recovered as a result of future investments to drill new wells, to recomplete existing wells and/or to install facilities to collect and deliver the production from existing and future wells and facilities.

Quarterly financial data (a)

	2019 three months ended				2018 three months ended			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**	Dec. 31	Sept. 30	June 30	Mar. 31
Financial data (millions of Canadian dollars)								
Total revenues and other income	**8,122**	**8,736**	**9,261**	**7,982**	7,890	9,732	9,543	7,934
Total expenses	**7,757**	**8,182**	**8,532**	**7,584**	6,804	8,706	9,279	7,237
Income (loss) before income taxes	**365**	**554**	**729**	**398**	1,086	1,026	264	697
Income taxes	**94**	**130**	**(483)**	**105**	233	277	68	181
Net income (loss)	**271**	**424**	**1,212**	**293**	853	749	196	516
Net income (loss) (millions of Canadian dollars)								
Upstream	**96**	**209**	**985**	**58**	(310)	222	(6)	(44)
Downstream	**225**	**221**	**258**	**257**	1,142	502	201	521
Chemical	**(2)**	**38**	**38**	**34**	55	69	78	73
Corporate and other	**(48)**	**(44)**	**(69)**	**(56)**	(34)	(44)	(77)	(34)
Net income (loss)	**271**	**424**	**1,212**	**293**	853	749	196	516
Per share information (Canadian dollars)								
Net income (loss) per common share - basic (b)	**0.36**	**0.56**	**1.58**	**0.38**	1.08	0.94	0.24	0.62
Net income (loss) per common share - diluted (b)	**0.36**	**0.56**	**1.57**	**0.38**	1.08	0.94	0.24	0.62
Dividends per common share - declared	**0.22**	**0.22**	**0.22**	**0.19**	0.19	0.19	0.19	0.16

(a) Quarterly data has not been audited by the company's independent auditors.

(b) Computed using the average number of shares outstanding during each period. The sum of the four quarters may not add to the full year.

Imperial

Esso Mobil