MANAGEMENT'S DISCUSSION AND ANALYSIS

1.0 Financial Summary

Selected Annual Information *($ millions, except where indicated)*	2017	2016	2015
Gross revenues and Marketing and other	**18,946**	13,224	16,801
Net earnings (loss) by business segment			
Upstream	**260**	1,091	(4,254)
Downstream	**448**	342	660
Corporate	**78**	(511)	(256)
Net earnings (loss)	**786**	922	(3,850)
Net earnings (loss) per share – basic	**0.75**	0.88	(3.95)
Net earnings (loss) per share – diluted	**0.75**	0.88	(4.01)
Adjusted net earnings (loss)(1)	**882**	(655)	149
Cash flow – operating activities	**3,704**	1,971	3,760
Funds from operations(1)	**3,306**	2,198	3,333
Ordinary dividends per common share(2)	**0.075**	—	0.900
Dividends per cumulative redeemable preferred share, series 1	**0.60**	0.73	1.11
Dividends per cumulative redeemable preferred share, series 2	**0.57**	0.42	—
Dividends per cumulative redeemable preferred share, series 3	**1.13**	1.13	1.19
Dividends per cumulative redeemable preferred share, series 5	**1.13**	1.25	0.90
Dividends per cumulative redeemable preferred share, series 7	**1.15**	1.15	0.62
Total assets	**32,927**	32,260	33,056
Net debt(3)	**2,927**	4,020	6,686

(1) *Adjusted net earnings and funds from operations are non-GAAP measures. The calculation of funds from operations changed in the second quarter of 2017. Prior periods have been revised to conform with the current period presentation. Refer to Section 9.3 for a reconciliation to the GAAP measures.*

(2) *Dividends declared for the third quarter of 2015 were issued in the form of common shares. The quarterly common share dividend was suspended in respect of the fourth quarter of 2015, but was reinstated during the first quarter of 2018. On February 28, 2018, the Board of Directors declared a quarterly dividend of $0.075 per common share for the three-month period ended December 31, 2017. The dividend will be payable on April 2, 2018 to shareholders of record at the close of business on March 20, 2018.*

(3) *Net debt is a non-GAAP measure. Refer to Section 9.3 for a reconciliation to the GAAP measure.*

2.0 Husky Business Overview

Husky Energy Inc. ("Husky" or the "Company") is one of Canada's largest integrated energy companies and is based in Calgary, Alberta. The Company's common shares are listed on the Toronto Stock Exchange ("TSX") under the symbol "HSE" and the Cumulative Redeemable Preferred Shares Series 1, Series 2, Series 3, Series 5 and Series 7 are listed under the symbols "HSE.PR.A", "HSE.PR.B", "HSE.PR.C", "HSE.PR.E" and "HSE.PR.G", respectively. The Company operates in Canada, the United States and the Asia Pacific region with Upstream and Downstream business segments.

2.1 Corporate Strategy

The Company's business strategy is to focus on returns from investment in a deep portfolio of opportunities that can generate increased funds from operations and free cash flow.

The Company has two main businesses: (i) an integrated Canada-U.S. Upstream and Downstream corridor ("Integrated Corridor"); and (ii) production located offshore the east coast of Canada ("Atlantic") and offshore China and Indonesia ("Asia Pacific") (Atlantic and Asia Pacific collectively, "Offshore").

Integrated Corridor

The Company's business in the Integrated Corridor includes crude oil, bitumen, natural gas and natural gas liquids ("NGL") production from Western Canada, the Lloydminster upgrading and asphalt refining complex, the Prince George Refinery, Husky Midstream Limited Partnership (35 percent working interest and operatorship), and the Lima, Toledo and Superior refineries in the U.S. midwest. Natural gas production from the Western Canada portfolio is closely aligned with the Company's energy requirements for refining and thermal bitumen production and acts as a natural hedge.

Offshore

The Company's Offshore business includes operations, development and exploration in Asia Pacific and Atlantic. Each area generates high-netback production, with near and long-term investment potential.

2.2 Operations Overview and 2017 Highlights

Upstream Operations

Upstream operations in the Integrated Corridor and Offshore include exploration for, and development and production of, crude oil, bitumen, natural gas and NGL ("Exploration and Production") and marketing of the Company's and other producers' crude oil, natural gas, NGL, sulphur and petroleum coke, pipeline transportation, the blending of crude oil and natural gas and storage of crude oil, diluent and natural gas ("Infrastructure and Marketing"). Infrastructure and Marketing markets and distributes products to customers on behalf of Exploration and Production and is grouped in the Upstream business segment based on the nature of its interconnected operations. The Company's Upstream operations are located primarily in Western Canada, Asia Pacific and Atlantic.

Exploration and Production

Thermal Developments

The Company is building on its thermal expertise by expanding its Lloyd thermal bitumen projects, and ramping up both the Tucker Thermal Project and the Sunrise Energy Project. The Company continued to advance its inventory of thermal projects in 2017. These long-life developments are being built with modular, repeatable designs and require low sustaining capital once brought online.

Total bitumen production, including Lloyd thermal projects, the Tucker Thermal Project and the Sunrise Energy Project, averaged 119,100 bbls/day in 2017.

Lloyd Thermal Projects

The Company expects to bring on 60,000 bbls/day of long-life thermal bitumen production over the next four years.

Development continued at the 10,000 bbls/day Rush Lake 2 Thermal Project. Construction of the central processing facility is progressing ahead of schedule (65 percent complete as of the end of 2017) and drilling of the 12 Steam-Assisted Gravity Drainage ("SAGD") injector-producer well pairs was completed in February 2018. First production is expected in the first quarter of 2019.

In late 2016, the Company sanctioned three Lloyd thermal projects with a total design capacity of 30,000 bbls/day at Dee Valley, Spruce Lake North and Spruce Lake Central. Regulatory approval for all three projects was received in 2017. Site clearing was completed at Dee Valley in the fourth quarter of 2017 and construction will commence in 2018. Site clearing and construction will start at Spruce Lake Central in 2018, and at Spruce Lake North site clearing will start in 2018 with construction commencing in 2019. First production for all three projects is expected in 2020.

In November 2017, the Company sanctioned two new 10,000 bbls/day thermal projects at Westhazel and Edam Central. First production for these two projects is expected in the second half of 2021.

Tucker Thermal Project

First oil was achieved at a new eight-well pad in the first quarter of 2017. Steaming commenced on a new 15-well pad drilled in the second quarter of 2017, with production expected to ramp up through the first half of 2018. Total production at the Tucker Thermal Project is expected to reach its 30,000 bbls/day design capacity by the end of 2018. In support of this, planned work to de-bottleneck the field and plant infrastructure is expected to be completed in the third quarter of 2018.

Sunrise Energy Project

Average annual production in 2017 was approximately 40,200 bbls/day (20,100 bbls/day Husky working interest), while December 2017 production averaged 47,100 bbls/day (23,550 bbls/day Husky working interest). The project is expected to reach its nameplate capacity of 60,000 bbls/day by the end of 2018.

14 previously drilled well pairs were tied in during 2017, with 13 well pairs on production in late 2017 and the remaining well pair on production in early 2018.

Western Canada

Western Canada continues to execute its resource play strategy to advance developments in the Spirit River (predominantly Wilrich) and Montney formations.

Oil and Natural Gas Resource Plays

A 16-well drilling program targeting the Spirit River formation in the Ansell and Kakwa areas was completed in the fourth quarter of 2017. 10 of the 16 wells drilled during the year were producing prior to the end of 2017. The remaining six wells will start production in early 2018. Due to improved operating efficiencies, drilling times were reduced by 30 percent during 2017, contributing to a 22 percent reduction in per-well drilling costs.

A drilling program targeting the oil and liquids-rich Montney formation in the Wembley and Karr areas is continuing. At Wembley, three wells were drilled in 2017, of which one well was producing prior to the end of 2017 and the other two wells are expected to be on production in 2018. At Karr, two wells were drilled and producing by the end of 2017.

Non-Thermal Developments

The Company is managing the natural decline in Cold Heavy Oil Production with Sand ("CHOPS") operations with an active optimization program as well as using Waterflooding and Polymer injection technology.

Enhanced Oil Recovery

In 2017, the Company operated five carbon dioxide ("CO_2") injection enhanced oil recovery ("EOR") pilot projects and a CO_2 capture and liquefaction plant at the Lloydminster Ethanol Plant. The liquefied CO_2 is used in the ongoing EOR piloting program. The Company is also piloting several types of CO_2 capture technology at the Lashburn facility in Saskatchewan.

Asia Pacific

Asia Pacific consists of the Liwan 3-1, Liuhua 34-2 and Liuhua 29-1 fields on Block 29/26 located in the South China Sea. The Madura Strait, offshore Indonesia, consists of the operating BD field, the MDA, MBH, MDK and MAC developments and three additional discoveries. The Company has rights to additional exploration blocks in the South China Sea, offshore Taiwan and Indonesia.

The Company continues to develop its fixed-price natural gas business offshore China and Indonesia, further protecting the Company from commodity price instability.

China

Block 29/26

Gross production from Liwan 3-1 and Liuhua 34-2 averaged 65,900 boe/day (32,300 boe/day Husky working interest) in 2017. Production consists of gross natural gas production of 312 mmcf/day and NGL production of 13,900 bbls/day. In comparison, 2016 production averaged 48,800 boe/day (24,800 boe/day Husky working interest), consisting of gross natural gas production of 224 mmcf/day and NGL production of 11,500 bbls/day.

A gas sales agreement was reached for future gas production from Liuhua 29-1, the third deepwater gas field at the Liwan Gas Project. The project was sanctioned in the fourth quarter of 2017. Construction is scheduled to begin in 2018 and first production is expected in 2021.

Blocks 15/33 and 16/25

On April 10, 2017, the Company signed a new production sharing contract ("PSC") for a new exploration block offshore China, Block 16/25, with China National Offshore Oil Corporation ("CNOOC"). Block 16/25 is located in the Pearl River Mouth Basin, about 150 kilometres southeast of the Hong Kong Special Administrative Region.

The Company expects to drill two exploration wells on the shallow water Block 16/25 during the 2018 timeframe, which are planned to be drilled in conjunction with the two planned exploration wells at the nearby exploration Block 15/33. The Company is the operator of both blocks during the exploration phase, with a working interest of 100 percent. In the event of a commercial discovery, CNOOC may assume a participating partnership interest of up to 51 percent in either or both blocks for the development and production phases.

Block DW-1

During 2017, on Block DW-1 offshore Taiwan, the Company completed the acquisition of three-dimensional seismic survey data. Analysis of the data has commenced to identify potential drilling prospects on the block.

Wenchang

The Company's participation in the Wenchang oilfields petroleum contract expired in November 2017 and the Company will not be entitled to any further production rights. The Company's share of light oil production averaged 5,300 bbls/day in 2017 compared to 6,600 bbls/day in 2016.

The Company had deposited funds of $95 million related to the Wenchang field for decommissioning and disposal expenses.

Indonesia

Madura Strait

Progress continued on the natural gas developments in the Madura Strait block. Total gross sales volumes from the BD Project, MDA-MBH and MDK fields are expected to be approximately 250 mmcf/day of natural gas (100 mmcf/day Husky working interest) and 6,000 bbls/day (2,400 bbls/day Husky working interest) of associated NGL once production is fully ramped up.

First gas production from the BD Project was achieved during the third quarter of 2017 and the first lifting of NGL occurred in mid-October. Gas is being sold from the onshore gas distribution facility in East Java under a fixed-price gas contract. NGL are produced and stored in the purpose built floating production, storage and offloading vessel ("FPSO"). Gross natural gas production averaged 20 mmcf/day (8 mmcf/day Husky working interest) and gross NGL production averaged 1,600 bbls/day (600 bbls/day Husky working interest) in 2017. The project is expected to ramp up in 2018 towards full sales gas rates, with a gross daily sales target of 100 mmcf/day of natural gas (40 mmcf/day Husky working interest) and 6,000 bbls/day of associated NGL (2,400 bbls/day Husky working interest).

Construction and installation of the shallow water jackets and subsea pipelines for the MDA-MBH fields were completed in the second quarter of 2017. The contract for a leased floating production unit has been signed and planning for the build has commenced. Drilling of five MDA field production wells and two MBH field production wells is planned for the first half of 2018, with first gas expected in the 2019 timeframe. The additional MDK shallow water field is expected to be tied in during the same period.

Pre-engineering activities progressed at the MAC field, where an approved Plan of Development is in place. Additional discoveries in the region are being evaluated for potential development.

Anugerah

During 2015, the Company acquired two-dimensional and three-dimensional seismic survey data on the contract area. An analysis of the data continues to be evaluated to determine the potential for future drilling opportunities.

Atlantic

The Company's Atlantic portfolio has short and long-term opportunities that provide for high return production growth.

White Rose Field and Satellite Extensions

In the second quarter of 2017, the Company and its partners announced plans to move ahead with the West White Rose Project offshore Newfoundland and Labrador. The project was sanctioned in May 2017 and will be developed using a fixed drilling platform, which has received regulatory approval. Contracts were awarded in the third quarter of 2017 and early development work commenced. Preparations for construction of the concrete gravity structure to support the topsides began in the fourth quarter of 2017 at the purpose-built graving dock in Argentia, Newfoundland and Labrador ("NL").The platform will leverage existing offshore infrastructure, including the *SeaRose* FPSO vessel. First oil is expected in 2022 with an expected ramp-up to gross peak production capacity of 75,000 bbls/day (52,500 bbls/day Husky working interest) in 2025 as development wells are drilled and brought online.

The Company continues to offset natural reservoir declines through infill and development well drilling at the White Rose field and satellite extensions. At North Amethyst, an infill well commenced production during the first quarter of 2017 with peak production of approximately 12,500 bbls/day (8,600 bbls/day Husky working interest). At South White Rose, an oil production well and a supporting water injection well were completed during the third quarter of 2017. An additional infill well was completed during the fourth quarter of 2017 drilled from the South White Rose field targeting the main White Rose field. All wells are tied back to the *SeaRose* FPSO, providing for improved capital efficiencies.

Atlantic Exploration

A new discovery at Northwest White Rose was announced in May 2017, and evaluation of results is ongoing. A potential development could leverage the *SeaRose* FPSO vessel, existing subsea infrastructure, and the West White Rose wellhead platform. The Company has a 93.232 percent ownership interest in the discovery.

In the first half of 2017, the Company and its partner drilled two exploration wells in the Flemish Pass that did not encounter economic quantities of hydrocarbons. The Company continues to evaluate the results of recent drilling programs in the Flemish Pass where it holds a 35 percent non-operated working interest in each of the Bay du Nord, Bay de Verde, Baccalieu, Harpoon and Mizzen discoveries. The Canada-Newfoundland and Labrador Offshore Petroleum Board ("C-NLOPB") issued a significant discovery licence for Bay du Nord in November 2017, which covers an area of 13,149 hectares.

In November 2017, the C-NLOPB announced that the Company was the successful bidder on a parcel of land in its 2017 land sale (50 percent Husky working interest). The lands cover an area of 121,453 hectares in the Jeanne d'Arc Basin. The lands are adjacent to the Company's other exploration licences in the basin.

Infrastructure and Marketing

Husky Midstream Limited Partnership

On July 15, 2016, the Company completed the sale of 65 percent of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan for gross proceeds of $1.69 billion in cash. The assets are held by Husky Midstream Limited Partnership ("HMLP"), of which the Company owns 35 percent, Power Assets Holdings Limited ("PAH") owns 48.75 percent and CK Infrastructure Holdings Limited ("CKI") owns 16.25 percent. The Company remains the operator of HMLP's assets.

HMLP has approximately 1,900 kilometres of pipeline in the Lloydminster region, storage at Hardisty and Lloydminster, and other ancillary assets. The pipeline systems transport blended heavy crude oil to Lloydminster, accessing markets through Husky's Upgrader and Asphalt Refinery. The Hardisty Terminal acts as the exclusive blending hub for Western Canada Select. HMLP is in the process of diversifying its operations beyond the Lloydminster and Hardisty area and has commercial support to enter the natural gas processing segment.

LLB Direct - Cold Lake Gathering System to Hardisty

During the year, HMLP commenced the construction of a new 150-kilometres pipeline system in Alberta, which creates additional pipeline capacity to handle the expected growth in the Company's thermal operations in Alberta and Saskatchewan. The construction is currently ahead of schedule and is expected to be completed in 2018.

Rush Lake 2 Line

Phase two of the Saskatchewan Gathering System Expansion commenced with construction activities on the Rush Lake 2 line. The multi-year expansion program is underway on several fronts and will provide transportation of diluent and heavy oil blend for several additional thermal plants.

Natural Gas Storage Facilities

The Company has operated a 25 bcf natural gas storage facility at Hussar, Alberta since 2000.

Commodity Marketing

The Company has developed its commodity marketing operations to include the acquisition of third-party volumes to enhance the value of its midstream assets. The Company also markets both its own and third-party production of crude oil, synthetic crude oil, NGL, natural gas and sulphur. Additionally, the Company markets petroleum coke, a by-product from the Lloydminster Upgrader, and its Ohio and Wisconsin refineries.

Downstream Operations

Downstream operations in the Integrated Corridor include upgrading of heavy crude oil feedstock into synthetic crude oil in Canada ("Upgrading"), refining crude oil in Canada, marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products, and production of ethanol ("Canadian Refined Products"). It also includes refining in the U.S. of primarily crude oil to produce and market diesel fuels, gasoline, jet fuel and asphalt that meet U.S. clean fuels standards ("U.S. Refining and Marketing"). Upgrading, Canadian Refined Products and U.S. Refining and Marketing all process and refine natural resources into marketable products and are grouped together as the Downstream business segment due to the similar nature of their products and services.

The Company's Downstream operations target three primary objectives: increasing feedstock flexibility to bring the best-priced crude to the Company's refineries, improving flexibility in the range of its products to capitalize on opportunities and enhancing market access to achieve the best returns. The Company's focused integration strategy helps to capture the margin on refined product pricing for its Western Canada heavy oil, bitumen and light oil production and assists in mitigating market volatility.

Upgrading

The heavy oil upgrading facility, located in Lloydminster, Saskatchewan, has a throughput capacity of 82,000 bbls/day. The Lloydminster Upgrader produces synthetic crude oil, diluent and ultra low sulphur diesel. It is designed to process blended heavy crude oil feedstock into high quality, low sulphur synthetic crude oil. Synthetic crude oil is used as refinery feedstock for the production of transportation fuels in Canada and the U.S. In addition, the Lloydminster Upgrader recovers diluent, which is blended with the heavy crude oil and bitumen prior to pipeline transportation to reduce viscosity and facilitate its movement, and returns it to the field to be reused. The Upgrader's current rated production capacity is 82,000 bbls/day of synthetic crude oil, diluent and ultra low sulphur diesel.

In the second quarter of 2017, a major turnaround was completed at the facility.

Canadian Refined Products

Lloydminster Asphalt Refinery
The Company is the largest marketer of paving asphalt in Western Canada. The Lloydminster Asphalt Refinery in Lloydminster, Alberta, has a throughput capacity of 29,000 bbls/day and is integrated with the local heavy oil and bitumen production, as well as transportation and upgrading infrastructure.

In the second quarter of 2017, a major turnaround was completed at the Asphalt Refinery.

A final investment decision for the potential expansion of the Lloydminster Asphalt Refinery has now been deferred to post-2020, in light of the Superior Refinery acquisition. The investment decision was initially planned for 2018.

Ethanol Plants
The Company is the largest producer of ethanol in Western Canada. The Company has two ethanol plants, one in Lloydminster, Saskatchewan and one in Minnedosa, Manitoba, with combined capacity of 260 million litres per year.

Prince George Refinery
The Prince George Refinery in British Columbia has a throughput capacity of 12,000 bbls/day and produces low sulphur gasoline and ultra-low sulphur diesel.

Branded Petroleum Product Outlets, Commercial Distribution and Truck Transportation Network
The Company is a major regional motor fuel marketer with an average of 518 retail marketing locations in 2017, including bulk plants and travel centres, with strategic land positions in Western Canada and Ontario.

In the third quarter of 2017, the Company and Imperial Oil closed their previously announced transaction to create a single expanded truck transport network of approximately 160 sites. As a result, the Company now has one of the largest cardlock networks in Canada.

U.S. Refining and Marketing

Lima Refinery

The Lima Refinery in Ohio has a throughput capacity of 165,000 bbls/day and produces low sulphur gasoline, gasoline blend stocks, ultra-low sulphur diesel, jet fuel, petrochemical feedstock and other by-products.

In 2016, the Company completed the first stage of the crude oil flexibility project and the refinery is now able to process up to 10,000 bbls/day of heavy crude oil feedstock. The project is designed to allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada when completed, providing the ability to swing between light and heavy crude oil feedstock.

The timing of completion for the crude oil flexibility project, which was expected to be completed around the end of 2018, has been updated and is expected to be completed in phases over a two-year period through 2018 and 2019. This revised schedule coordinates project work with normal maintenance to provide higher levels of sustained production.

BP-Husky Toledo Refinery

The BP-Husky Toledo Refinery in Ohio has a name plate throughput capacity of 160,000 bbls/day and produces low sulphur gasoline, ultra-low sulphur diesel, aviation fuels, propane and asphalt. The crude oil refinery is owned 50 percent by the Company and 50 percent by BP Corporation North America Inc ("BP"), and is operated by BP. The Company and its partner completed a feedstock optimization project in 2016, allowing the refinery to process approximately 55,000 to 70,000 bbls/day of high content naphthenic acids ("high-TAN") crude oil to support production from the Sunrise Energy Project. The refinery's overall nameplate capacity remained unchanged.

Superior Refinery

On November 8, 2017, the Company completed the purchase of the Superior Refinery, a 50,000 bbls/day permitted capacity facility located in Superior, Wisconsin, U.S., from Calumet Specialty Products Partners, L.P. ("Calumet") for $670 million (US$527 million) in cash, which includes $108 million (US$85 million) of working capital, subject to final adjustments. The refinery produces gasoline, diesel, asphalt and heavy fuel oils.

A project to increase the heavy oil processing capacity at the Superior Refinery is expected to be completed in the first half of 2018.

2.3 Financial Strategic Plan

The Company is committed to ensuring sufficient liquidity, financial flexibility and access to long-term capital to fund its growth. The Company maintains undrawn committed term credit facilities with a portfolio of creditworthy financial institutions and other sources of liquidity to provide timely access to funding to supplement cash flow.

The Company intends to continue maintaining a healthy balance sheet to provide financial flexibility. The Company's target is to maintain a debt to funds from operations ratio of less than 2.0 times and a debt to capital employed ratio of less than 25 percent. Debt to funds from operations and debt to capital employed are both non-GAAP measures (refer to Sections 6.4 and 9.3). The Company is committed to retaining its investment grade credit ratings to support access to debt capital markets. The Company has taken measures to strengthen its financial position and navigate through commodity cycles. Past measures included, but were not limited to, a reduction of budgeted capital spending, the suspension of the quarterly common share dividend, the sale of non-core assets in Western Canada and the continued transition to higher return production. Refer to Section 6.0 for additional information on the Company's liquidity and capital resources.

In 2017, the Company:

- Issued $750 million in notes maturing March 10, 2027, with a coupon of 3.60 percent.
- Repaid the maturing 6.20 percent notes issued under a trust indenture dated September 11, 2007. The amount paid to note holders was $365 million, including $11 million of interest.
- Completed the sale of select assets in Western Canada, representing approximately 20,200 boe/day for gross proceeds of approximately $185 million.

3.0 The 2017 Business Environment

The Company's operations are significantly influenced by domestic and international factors including, but not limited to, the following:

- The global crude oil market continued to rebalance, with production reductions by certain members of the Organization of the Petroleum Exporting Countries ("OPEC") and non-OPEC members, leading to higher key crude oil benchmarks in 2017. The production cuts were partially offset by increased production from OPEC members not bound to the production restrictions and growth in U.S. shale oil production.
- The U.S. Energy Information Administration ("EIA") estimated that global demand for crude oil increased by an estimated 1.6 mmboe/day in 2017 and is forecasted to increase by 1.7 mmboe/day in 2018.
- North American natural gas benchmarks continued to be weak in 2017 due to an oversupply of natural gas in North America, which is largely the result of technological advances in horizontal drilling and hydraulic fracturing that have unlocked significant reserves.
- The cost of the U.S. Renewable Fuels Standard legislation has become a material economic factor for refineries in the U.S. U.S. refiners observed significant volatility in the price of Renewable Identification Numbers ("RINs") in 2017.
- The Canadian dollar strengthened against the U.S. dollar in 2017 compared to 2016.
- Alternative and improved extraction methods have rapidly evolved in North American and international onshore and offshore activity.
- A continuing emphasis on environmental, the impacts of climate change, health and safety, enterprise risk management, resource sustainability and corporate social responsibility concerns.
- The income tax effects related to the reduction in the U.S. Federal corporate tax rate that will take effect in 2018.
- Transportation constraints on crude oil produced in western Canada. The oil and gas industry continues to work with stakeholders to develop a strong network of transportation infrastructure including pipelines, rail, marine and trucks. The development of a strong infrastructure network continues to be an important challenge for the industry in order to obtain market access for the growing supply of crude oil from the western Canadian oil sands.

Major business factors are considered in the formulation of the Company's short and long term business strategy.

The Company is exposed to a number of risks inherent in the exploration, development, production, marketing, transportation, storage and sale of crude oil, liquids-rich natural gas and related products. For a discussion on Risk and Risk Management, see Section 5.0 and the Company's Annual Information Form for the year ended December 31, 2017.

Average Benchmarks

Commodity prices, refining crack spreads and foreign exchange rates are some of the most significant factors that affect the results of the Company's operations. The following average benchmarks have been provided to assist in understanding the Company's financial results.

Average Benchmarks Summary		2017	2016
West Texas Intermediate ("WTI") crude oil[(1)]	(US$/bbl)	**50.95**	43.32
Brent crude oil[(2)]	(US$/bbl)	**54.28**	43.69
Light sweet at Edmonton	($/bbl)	**62.91**	52.99
Daqing[(3)]	(US$/bbl)	**51.78**	40.86
Western Canada Select at Hardisty[(4)]	(US$/bbl)	**38.98**	29.48
Lloyd heavy crude oil at Lloydminster	($/bbl)	**44.36**	32.61
WTI/Lloyd crude blend differential	(US$/bbl)	**11.76**	13.70
Condensate at Edmonton	(US$/bbl)	**51.57**	42.47
NYMEX natural gas[(5)]	(US$/mmbtu)	**3.11**	2.46
Nova Inventory Transfer ("NIT") natural gas	($/GJ)	**2.30**	1.98
Chicago Regular Unleaded Gasoline	(US$/bbl)	**66.22**	56.07
Chicago Ultra-low Sulphur Diesel	(US$/bbl)	**69.05**	56.48
Chicago 3:2:1 crack spread	(US$/bbl)	**16.31**	12.74
U.S./Canadian dollar exchange rate	(US$)	**0.771**	0.755
Canadian Equivalents[(6)]			
WTI crude oil	($/bbl)	**66.08**	57.38
Brent crude oil	($/bbl)	**70.40**	57.87
Daqing	($/bbl)	**67.16**	54.12
Western Canada Select at Hardisty	($/bbl)	**50.56**	39.05
WTI/Lloyd crude blend differential	($/bbl)	**15.25**	18.15
NYMEX natural gas	($/mmbtu)	**4.03**	3.26

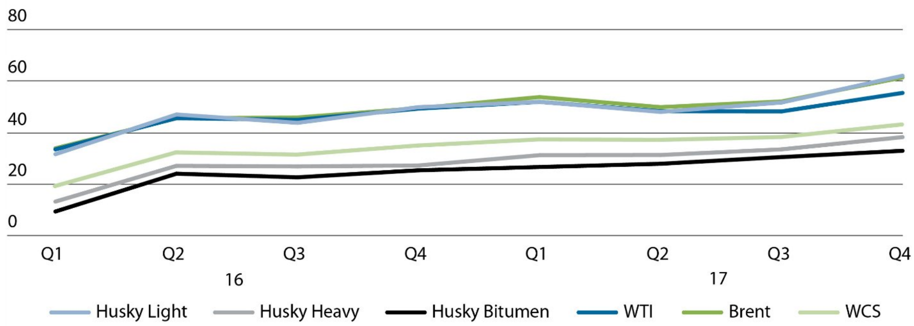
(1) *Calendar Month Average of settled prices for West Texas Intermediate at Cushing, Oklahoma.*
(2) *Calendar Month Average of settled prices for Dated Brent.*
(3) *Calendar Month Average of settled prices for Daqing.*
(4) *Western Canadian Select is a heavy blended crude oil, comprised of conventional and bitumen crude oils, blended with diluent, which terminals at Hardisty, Alberta. Quoted prices are indicative of the Index for Western Canadian Select at Hardisty, Alberta, set in the month prior to delivery.*
(5) *Prices quoted are average settlement prices during the period.*
(6) *Prices quoted are calculated using U.S. dollar benchmark commodity prices and U.S./Canadian dollar exchange rates.*

As an integrated producer, the Company's profitability is largely determined by realized prices for crude oil and natural gas, marketing margins on committed pipeline capacity and refinery margins, as well as the effect of changes in the U.S./Canadian dollar exchange rate. All of the Company's crude oil production and the majority of its natural gas production receives the prevailing market price. The price realized for crude oil is determined by North American and global factors. The price realized for natural gas production from Western Canada is determined primarily by North American fundamentals since virtually all natural gas production in North America is consumed by North American customers. In Asia Pacific, the natural gas price is determined by fixed long-term sales contracts.

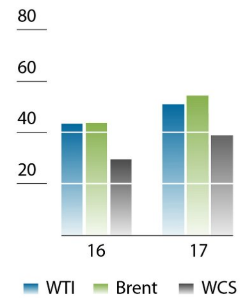
The Downstream segment is heavily impacted by the price of crude oil and natural gas, as the largest cost factor in the Downstream segment is crude oil feedstock, a portion of which is heavy crude oil and bitumen. In the Upgrading business, heavy crude oil feedstock is processed into light synthetic crude oil. The Company's U.S. Refining and Marketing business processes a mix of different types of crude oil from various sources, but the mix is primarily light sweet crude oil at the Lima Refinery and approximately 55 percent heavy crude oil and bitumen feedstock at the BP-Husky Toledo Refinery. The Company's Canadian Refined Products business relies primarily on purchased refined products for resale in the retail distribution network. Refined products are acquired, under supply contracts, from other Canadian refiners or gasoline and diesel production from the Prince George Refinery and diesel production from the Lloydminster Upgrader.

Crude Oil Benchmarks

West Texas Intermediate, Brent, Western Canada Select and Husky Average Crude Oil Prices
(US$/bbl)



Average WTI, Brent and WCS
(US$/bbl)



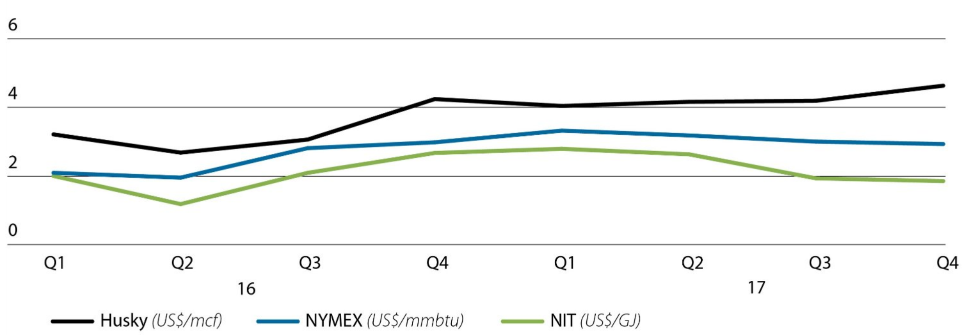
Global crude oil benchmarks strengthened in 2017 primarily due to the production reductions made by certain members of OPEC and some key non-OPEC producers, along with global demand growth of an estimated 1.6 mmboe/day per the EIA. The production cuts were partially offset by increased production from OPEC members not bound to the production restrictions and growth in U.S. shale oil production. WTI averaged US$50.95/bbl in 2017 compared to US$43.32/bbl in 2016. Brent averaged US$54.28/bbl in 2017 compared to US$43.69/bbl in 2016.

The price received by the Company for crude oil production from Western Canada is primarily driven by the price of WTI, adjusted to Western Canada. The price received by the Company for crude oil production from Atlantic is primarily driven by the price of Brent and the price received by the Company for crude oil and NGL production from Asia Pacific is primarily driven by the price of Daqing. The majority of the Company's crude oil production from Western Canada is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In 2017, approximately 70 percent of the Company's crude oil and NGL production was heavy crude oil or bitumen compared to approximately 66 percent in 2016.

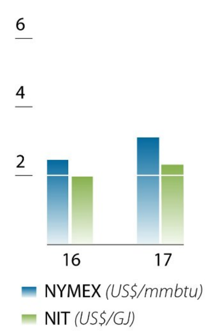
The Company's heavy crude oil and bitumen production is blended with diluent (condensate) in order to facilitate its transportation through pipelines. Therefore, the price received for a barrel of blended heavy crude oil or bitumen is impacted by the prevailing market price for condensate. The price of condensate at Edmonton increased in 2017 primarily due to the increase in crude oil benchmark pricing.

Natural Gas Benchmarks

NYMEX Natural Gas, NIT Natural Gas and Husky Average Natural Gas Prices



Average NYMEX and NIT



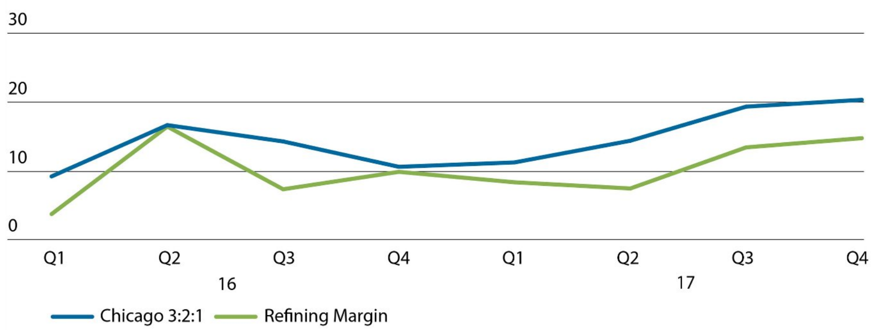
North American natural gas benchmarks continued to be weak in 2017 due to the continued oversupply of natural gas in North America. The oversupply is largely the result of technological advances in horizontal drilling and hydraulic fracturing that have unlocked significant reserves that were not economical under previously applied extraction methods. The NIT natural gas price benchmark increased in 2017 compared to 2016 due to a temporary decline in natural gas demand from Canadian oil sands operations in 2016, resulting from the wildfire at Fort McMurray, Alberta.

The price received by the Company for natural gas production from Western Canada is primarily driven by the NIT near-month contract price of natural gas, while the price received by the Company for production from Asia Pacific is largely set through fixed long-term sales contracts.

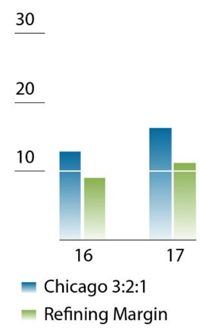
North American natural gas is consumed internally by the Company's Upstream and Downstream operations, helping to mitigate the impact of weak North American natural gas benchmark prices on the Company's results.

Refining Benchmarks

Chicago Average Crack Spread and Husky Realized U.S. Refining Margin
(US$/bbl)



Average Crack Spread
(US$/bbl)

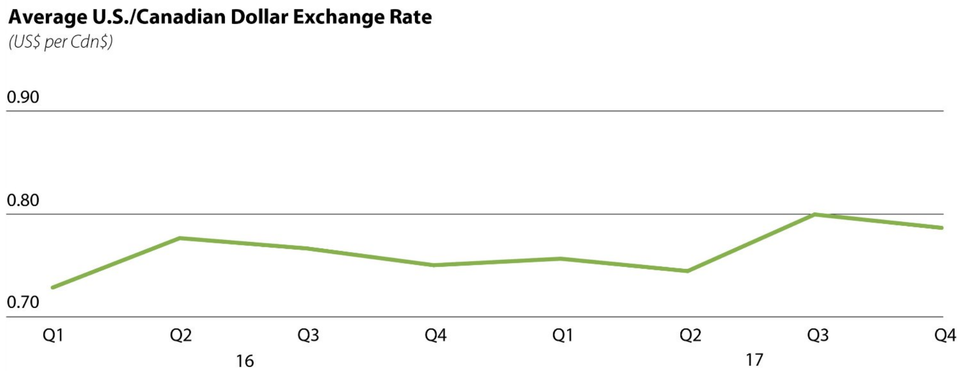


The Chicago 3:2:1 crack spread is the key indicator for U.S. refining margins and reflects refinery gasoline output that is approximately twice the distillate output, and is calculated as the price of two-thirds of a barrel of gasoline plus one-third of a barrel of distillate fuel less one barrel of crude oil. Market crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel and do not reflect the actual crude purchase costs or the product configuration of a specific refinery. The Chicago Regular Unleaded Gasoline and the Chicago Ultra-low Sulphur Diesel average benchmark prices are the standard products included in the Chicago 3:2:1 crack spread. The Chicago 3:2:1 crack spread is based on last in first out ("LIFO") accounting.

The cost of the U.S. Renewable Fuels Standard legislation has become a material economic factor for refineries in the U.S. The Chicago 3:2:1 crack spread is a gross margin based on the prices of unblended fuels. The cost of purchasing RINs or physical biofuel blending into a final gasoline or diesel has not been deducted from the Chicago 3:2:1 gross margin. The market value of gasoline or distillate that has been blended may be lower than the value of unblended petroleum products given the value a buyer of unblended petroleum can gain by generating a RIN through blending. The Company sells both blended fuels and unblended fuels with the goal of maximizing margins net of RINs purchases.

The Company's realized refining margins are affected by the product configuration of its refineries, crude oil feedstock, product slates, transportation costs to benchmark hubs and the time lag between the purchase and delivery of crude oil. The product slates produced at the Lima, BP-Husky Toledo and Superior refineries contain approximately 10 to 30 percent of other products that are sold at discounted market prices compared to gasoline and distillate. The Company's realized refining margins are accounted for on a first in first out ("FIFO") basis in accordance with International Financial Reporting Standards ("IFRS").

Foreign Exchange



The majority of the Company's revenues are received in U.S. dollars from the sale of oil and gas commodities and refined products whose prices are determined by reference to U.S. benchmark prices. The majority of the Company's non-hydrocarbon related expenditures are denominated in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. In addition, changes in foreign exchange rates impact the translation of U.S. Downstream and Asia Pacific operations and U.S. dollar-denominated debt. In 2017, the Canadian dollar averaged US$0.771 compared to US$0.755 in 2016.

The Company's long-term sales contracts in China are priced in Chinese Yuan ("RMB") and, therefore, an increase in the value of RMB relative to the Canadian dollar will increase the revenues received in Canadian dollars from the sale of these natural gas commodities in the region. The Canadian dollar averaged RMB 5.208 in 2017 compared to RMB 5.012 in 2016.

Sensitivity Analysis

The following table is indicative of the impact of changes in certain key variables in 2017 on earnings before income taxes and net earnings. The table below reflects what the expected effect would have been on the financial results for 2017 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2017. Each separate item in the sensitivity analysis shows the approximate effect of an increase in that variable only; all other variables are held constant. While these sensitivities are indicative for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or upon greater magnitudes of change.

Sensitivity Analysis	2017 Average	Increase	Effect on Earnings before Income Taxes[(1)]		Effect on Net Earnings[(1)]	
			($ millions)	*($/share)*[(2)]	*($ millions)*	*($/share)*[(2)]
WTI benchmark crude oil price[(3)(4)]	**50.95**	*US$1.00/bbl*	**101**	**0.10**	**73**	**0.07**
NYMEX benchmark natural gas price[(5)]	**3.11**	*US$0.20/mmbtu*	**9**	**0.01**	**7**	**0.01**
WTI/Lloyd crude blend differential[(6)]	**11.76**	*US$1.00/bbl*	**(9)**	**(0.01)**	**(6)**	**(0.01)**
Canadian asphalt margins	**19.96**	*Cdn $1.00/bbl*	**10**	**0.01**	**7**	**0.01**
Canadian light oil margins	**0.052**	*Cdn $0.005/litre*	**13**	**0.01**	**10**	**0.01**
Chicago 3:2:1 crack spread	**16.31**	*US$1.00/bbl*	**123**	**0.12**	**78**	**0.08**
Exchange rate (US $ per Cdn $)[(3)(7)]	**0.771**	*US$0.01*	**(64)**	**(0.06)**	**(46)**	**(0.05)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 1,005.1 million common shares outstanding as of December 31, 2017.*
(3) *Does not include gains or losses on inventory.*
(4) *Includes impacts related to Brent-based production.*
(5) *Includes impact of natural gas consumption.*
(6) *Revised to reflect the impact of Infrastructure and Marketing. Excludes impact on Canadian asphalt operations.*
(7) *Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.*

4.0 Results of Operations

4.1 Segment Earnings

Segmented Earnings	Earnings (Loss) before Income Taxes		Net Earnings (Loss)		Capital Expenditures[1]	
($ millions)	**2017**	2016	**2017**	2016	**2017**	2016
Upstream						
Exploration and Production	**239**	(298)	**174**	(217)	**1,476**	872
Infrastructure and Marketing	**118**	1,430	**86**	1,308	**—**	54
Downstream						
Upgrading	**151**	241	**110**	175	**230**	51
Canadian Refined Products	**142**	151	**104**	110	**87**	52
U.S. Refining and Marketing	**371**	90	**234**	57	**313**	623
Corporate	**(597)**	(664)	**78**	(511)	**114**	53
Total	**424**	950	**786**	922	**2,220**	1,705

[1] *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*

4.2 Upstream

Exploration and Production

Exploration and Production Earnings Summary *($ millions)*	**2017**	2016
Gross revenues	**4,978**	4,036
Royalties	**(363)**	(305)
Net revenues	**4,615**	3,731
Purchases of crude oil and products	**—**	32
Production, operating and transportation expenses	**1,650**	1,760
Selling, general and administrative expenses	**265**	232
Depletion, depreciation, amortization and impairment ("DD&A")	**2,237**	1,815
Exploration and evaluation expenses	**146**	188
Gain on sale of assets	**(42)**	(192)
Other – net	**6**	53
Share of equity investment (gain) loss	**(12)**	1
Financial items	**126**	140
Provisions for (recovery) of income taxes	**65**	(81)
Net earnings (loss)	**174**	(217)

Exploration and Production net revenues increased by $884 million in 2017 compared to 2016, primarily due to higher realized global commodity prices combined with increased production from the Company's thermal development projects and increased production in Asia Pacific. The increase was partially offset by lower oil and natural gas production in Western Canada due to the disposition of select legacy assets in 2016 and 2017.

Selling, general and administrative expenses increased by $33 million in 2017 compared to 2016 primarily due to an increase in employee costs and contract services.

Gain on sale of assets decreased by $150 million in 2017 compared to 2016 primarily due to the decrease in asset dispositions in 2017.

Provisions for income taxes increased by $146 million in 2017 compared to 2016 primarily due to higher earnings before income taxes in 2017 compared to 2016.

Average Sales Prices Realized

Average Sales Prices Realized	2017	2016
Crude oil and NGL *($/bbl)*		
Light & Medium crude oil	**67.36**	52.40
NGL	**44.18**	38.01
Heavy crude oil	**43.38**	30.50
Bitumen	**38.20**	27.63
Total crude oil and NGL average	**46.09**	35.78
Natural gas average *($/mcf)* (1)	**5.52**	4.40
Total average *($/boe)*	**42.47**	33.08

(1) Reported average natural gas prices include Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.

The average sales prices realized by the Company for crude oil and NGL production increased by 29 percent in 2017 compared to 2016, reflecting an increase in global crude oil benchmarks.

The average sales prices realized by the Company for natural gas increased by 25 percent in 2017 compared to 2016. The increase was primarily due to a higher percentage of fixed-priced natural gas production from the Liwan and BD gas projects relative to total natural gas production.

Daily Gross Production

Daily Gross Production	2017	2016
Crude oil and NGL *(mbbls/day)*		
Western Canada		
Light & Medium crude oil	**12.1**	23.4
NGL	**10.5**	8.0
Heavy crude oil	**44.4**	54.1
Bitumen(1)	**119.1**	97.4
	186.1	182.9
Atlantic		
White Rose and satellite extensions – light crude oil	**30.0**	28.8
Terra Nova – light crude oil	**4.0**	4.3
	34.0	33.1
Asia Pacific		
Wenchang – light crude oil	**5.3**	6.6
Liwan and Wenchang – NGL(2)	**7.0**	6.0
Madura – NGL(3)	**0.6**	—
	12.9	12.6
	233.0	228.6
Natural gas *(mmcf/day)*		
Western Canada	**378.2**	442.4
Asia Pacific		
Liwan(2)	**152.9**	113.5
Madura(3)	**8.0**	—
	160.9	113.5
	539.1	555.9
Total *(mboe/day)*	**322.9**	321.2

(1) Bitumen consists of production from thermal developments in Lloydminster, the Tucker Thermal Project located near Cold Lake, Alberta and the Sunrise Energy Project.
(2) Reported production volumes include Husky's working interest production from the Liwan Gas Project (49 percent).
(3) Reported production volumes include Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.

Crude Oil and NGL Production

Crude oil and NGL production increased by 4.4 mbbls/day, or two percent, in 2017 compared to 2016. The increase was primarily due to the continued production ramp-up at the Sunrise Energy Project, new production from the Edam West, Vawn and Edam East thermal developments, and increased NGL production in Asia Pacific and Western Canada. This was partially offset by lower crude oil production from Western Canada due to the disposition of select legacy assets in 2016 and 2017.

Natural Gas Production

Natural gas production decreased by 16.8 mmcf/day, or three percent, in 2017 compared to 2016. In Western Canada, natural gas production decreased by 64.2 mmcf/day, primarily due to the disposition of select legacy assets during 2016 and 2017, natural reservoir declines from mature properties and strategic shut-ins due to unfavourable economics. In Asia Pacific, natural gas production increased by 47.4 mmcf/day, primarily due to increased gas demand at the Liwan Gas Project and new production from the BD Project in 2017.

Exploration and Production Revenue Mix *(Percentage of Upstream Net Revenues)*	**2017**	2016
Crude oil and NGL		
Light & Medium crude oil	**25%**	32%
NGL	**6%**	5%
Heavy crude oil	**14%**	15%
Bitumen	**33%**	25%
Crude oil and NGL	**78%**	77%
Natural gas	**22%**	23%
Total	**100%**	100%

2018 Production Guidance and 2017 Actual

	Guidance	**Year ended December 31**	Guidance
Gross Production	2018	**2017**	2017
Canada			
Light & Medium crude oil *(mbbls/day)*	46 - 49	**46**	46 - 48
NGL *(mbbls/day)*	10 - 11	**10**	8 - 9
Heavy crude oil & bitumen *(mbbls/day)*	174 - 181	**164**	167 - 173
Natural gas *(mmcf/day)*	280 - 290	**378**	345 - 353
Canada total *(mboe/day)*	277 - 289	**283**	278 - 288
Asia Pacific			
Light crude oil *(mbbls/day)*	0 - 0	**5**	5 - 6
NGL *(mbbls/day)*	10 - 11	**8**	8 - 10
Natural gas *(mmcf/day)*[(1)]	200 - 210	**161**	171 - 182
Asia Pacific total *(mboe/day)*	43 - 46	**40**	42 - 46
Total *(mboe/day)*	320 - 335	**323**	320 - 335

[(1)] *Includes Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.*

Total production for the year ended December 31, 2017 was within the production guidance. The expected total production volumes in 2018 will remain comparable to 2017 after factoring in the Western Canada dispositions during the year. The 2018 production guidance reflects the ramp up of the Tucker Thermal Project, Sunrise Energy Project, and BD Project. The increases are anticipated to be offset by continued natural declines from mature properties in Atlantic and Western Canada, and decline in light crude oil production from Asia Pacific, as the PSC for the Wenchang field expired in 2017.

Factors that could potentially impact the Company's production performance in 2018 include, but are not limited to:

- changes in crude oil and natural gas prices such as increases in commodity pricing, which may result in the decision to accelerate near-term growth projects, or decreases in commodity pricing, which may result in the decision to temporarily shut-in production or delay capital expenditures.
- performance of recently commissioned facilities, new wells brought onto production and unanticipated reservoir response from existing fields.
- potential divestment of certain producing crude oil or natural gas properties in Western Canada.
- unplanned or extended maintenance and turnarounds at any of the Company's operated or non-operated facilities, upgrading, refining, pipeline or offshore assets.
- business interruptions due to unexpected events such as severe weather, fires, blowouts, freeze-ups, equipment failures, unplanned and extended pipeline shutdowns and other similar events.
- defaults by contracting parties whose services, goods or facilities are necessary for the Company's production.
- operations and assets which are subject to a number of political, economic and socio-economic risks.

Royalties

Royalty rates as a percentage of gross revenues averaged seven percent in 2017 compared to eight percent in 2016. Royalty rates in Western Canada averaged seven percent in both 2017 and 2016. Royalty rates in Atlantic averaged nine percent in 2017 compared to 15 percent in 2016, primarily due to production shifting to lower rate fields in 2017 combined with higher eligible costs. Royalty rates in Asia Pacific averaged six percent in both 2017 and 2016.

Operating Costs

Operating Costs *($ millions)*	**2017**	2016
Western Canada	**1,331**	1,413
Atlantic	**213**	224
Asia Pacific	**94**	92
Total	**1,638**	1,729
Per unit operating costs *($/boe)*	**13.93**	14.04

Total Exploration and Production operating costs were $1,638 million in 2017 compared to $1,729 million in 2016. Total Upstream unit operating costs averaged $13.93/boe in 2017 compared to $14.04/boe in 2016 with the decrease primarily attributable to lower unit operating costs per boe in Atlantic and Asia Pacific.

Per unit operating costs in Western Canada averaged $14.67/boe in 2017 compared to $14.21/boe in 2016. The increase in unit operating costs per boe was primarily attributable to higher energy costs and lower production in 2017, partially offset by cost savings initiatives realized in 2017.

Per unit operating costs in Atlantic averaged $17.12/boe in 2017 compared to $18.48/boe in 2016. The decrease in unit operating costs per boe was primarily due to higher production and lower subsea maintenance costs in 2017.

Per unit operating costs in Asia Pacific averaged $6.47/boe in 2017 compared to $8.01/boe in 2016. The decrease in unit operating costs per boe was primarily attributable to higher production at the Liwan Gas Project and cost saving initiatives.

Exploration and Evaluation Expenses

Exploration and Evaluation Expenses *($ millions)*	**2017**	2016
Seismic, geological and geophysical	**113**	78
Expensed drilling	**22**	66
Expensed land	**11**	44
Total	**146**	188

Exploration and evaluation expenses were $146 million in 2017 compared to $188 million in 2016. The increase in seismic, geological and geophysical expense of $35 million was primarily due to increased seismic operations in Asia Pacific. The decrease in expensed drilling was primarily attributable to lower daily drilling rates for the two unsuccessful exploration wells in the Flemish Pass in 2017 relative to 2016. The decrease in expensed land was primarily attributable to the 2016 pre-tax write off of $35 million of land in Western Canada.

Depletion, Depreciation, Amortization and Impairment

DD&A expense increased by $422 million in 2017 compared to 2016 primarily due to the recognition of a pre-tax impairment charge of $173 million on assets located in Western Canada due to changes in development plans and reinforced by market transactions in 2017. In 2016, the Company recognized a net pre-tax impairment reversal of $261 million on assets located in Western Canada due to the acceleration of forecasted production and revised operational economics, based on recent production performance and market transactions. In 2017, total DD&A excluding impairment averaged $17.61/boe compared to $17.67/boe in 2016.

Exploration and Production Capital Expenditures

Exploration and Production capital expenditures were higher in 2017 compared to 2016 reflecting increased investment in thermal developments, Atlantic and Western Canada. Exploration and Production capital expenditures were as follows:

Exploration and Production Capital Expenditures[1] *($ millions)*	**2017**	2016
Exploration		
Western Canada	**63**	18
Thermal developments	**8**	6
Atlantic	**67**	18
Asia Pacific[2]	**10**	4
	148	46
Development		
Western Canada	**196**	116
Thermal developments	**534**	312
Non-thermal developments	**106**	51
Atlantic	**417**	226
Asia Pacific[2]	**2**	114
	1,255	819
Acquisitions		
Western Canada	**25**	—
Thermal developments	**48**	7
	73	7
	1,476	872

(1) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*

(2) *Capital expenditures in Asia Pacific exclude amounts related to the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for consolidated financial statement purposes.*

Western Canada

During 2017, $284 million (19 percent) was invested in Western Canada compared to $134 million (15 percent) in 2016. Capital expenditures in 2017 related primarily to resource play development drilling targeting the Spirit River formation in the Ansell and Kakwa areas and the Montney formation in the Karr and Wembley areas.

Thermal Developments

During 2017, $590 million (40 percent) was invested in thermal developments compared to $325 million (37 percent) in 2016. Capital expenditures in 2017 related primarily to the Rush Lake 2 thermal development, a new 15-well pad at the Tucker Thermal Project and continued investment in the Sunrise Energy Project.

Non-Thermal Developments

During 2017, $106 million (seven percent) was invested in non-thermal developments compared to $51 million (six percent) in 2016. Capital expenditures in 2017 related primarily to sustainment activities.

Atlantic

During 2017, $484 million (33 percent) was invested in Atlantic compared to $244 million (28 percent) in 2016. Capital expenditures in 2017 related primarily to satellite extension developments at North Amethyst, the South White Rose Extension and the West White Rose Project as well as delineation drilling northwest of the main White Rose field.

Asia Pacific

During 2017, $12 million (one percent) was invested in Asia Pacific compared to $118 million (14 percent) in 2016. The decrease in capital expenditures in 2017 compared to 2016 reflects the installation of a second deepwater production pipeline at Liwan Gas Project in 2016.

Exploration and Production Wells Drilled

Onshore drilling activity

The following table discloses the number of wells drilled in thermal developments, non-thermal developments and Western Canada during 2017 and 2016:

	2017		2016	
Wells Drilled *(wells)*[1]	Gross	Net	Gross	Net
Thermal developments[2]	**64**	**64**	70	70
Non-thermal developments	**29**	**27**	5	5
Western Canada	**36**	**33**	3	2
	129	**124**	78	77

[1] *Excludes service/stratigraphic test wells for evaluation purposes.*
[2] *Includes producer and injector wells.*

Thermal developments consisted of drilling and completion activity related to the Rush Lake 2 development and a new 15-well pad at the Tucker Thermal Project. Western Canada drilling and completion activity increased due to the 16-well program targeting the Spirit River formation in the Ansell and Kakwa areas, as well as a drilling program targeting the Montney formation in the Karr and Wembley areas.

Offshore drilling activity

The following table discloses the Company's offshore drilling activity during 2017:

Region	Well	Working Interest	Well Type
Atlantic	North Amethyst G-25 10	68.875 percent	Development
Atlantic	South White Rose J-05 5	68.875 percent	Development
Atlantic	South White Rose J-05 7	72.500 percent	Development
Atlantic	White Rose A-78	93.232 percent	Exploration
Atlantic	Bonaventure O-96	35 percent	Exploration
Atlantic	Portugal Cove E-38	35 percent	Exploration

2018 Upstream Capital Expenditures Program

2018 Upstream Capital Expenditures Program *($ millions)*	
Thermal developments	**895 - 930**
Non-thermal developments	**85 - 90**
Western Canada	**270 - 285**
Atlantic	**750 - 775**
Asia Pacific[1]	**130 - 150**
Total Upstream capital expenditures	**2,130 - 2,230**

[1] *Capital expenditures in Asia Pacific exclude amounts related to the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for consolidated financial statement purposes.*

The 2018 Upstream capital expenditures program reflects a focus on short and medium-cycle projects in the Integrated Corridor business, including further growing the Lloyd thermal bitumen portfolio and the Ansell resource play in Western Canada. In the Offshore business, the capital expenditures program will support the start of construction at the Liuhua 29-1 field offshore China and the West White Rose Project in Atlantic.

The Company has budgeted $895 - $930 million in thermal developments for 2018, primarily for the development of Rush Lake 2, Dee Valley, Spruce Lake North and Spruce Lake Central. Capital expenditures will also take place in support of environmental and regulatory work on Westhazel and Edam Central, which were projects sanctioned in the fourth quarter of 2017. The Company is making progress in its strategy to transition a greater percentage of production to long-life thermal bitumen production and the 2018 Upstream capital expenditures program will continue to build on this momentum.

The Company has budgeted $85 - $90 million in non-thermal developments for 2018, primarily for sustainment activities.

The Company has budgeted $270 - $285 million in Western Canada for 2018, primarily for the planned drilling activities in the Spirit River formation in the Ansell and Kakwa areas as well as the Montney formation.

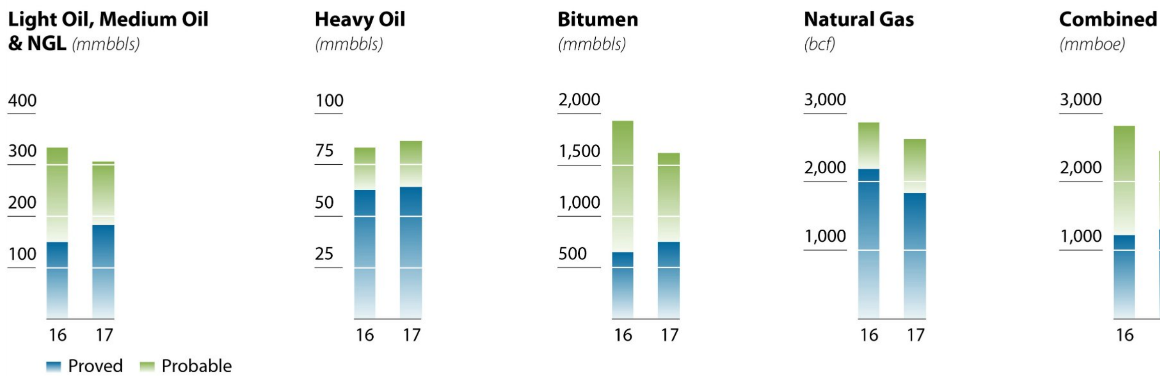
The Company has budgeted $750 - $775 million in Atlantic for 2018, primarily for the construction of the West White Rose Project.

The Company has budgeted $130 - $150 million in Asia Pacific in 2018, primarily for the continued development of the third field of the Liwan Gas Project, Liuhua 29-1.

Oil and Gas Reserves

The Company's reserves disclosure was prepared in accordance with Canadian Securities Administrators' National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") effective December 31, 2017 with a preparation date of January 31, 2018.

Proved and Probable Reserves at December 31:



Note: All Lloydminster thermal reserves are classified as bitumen.

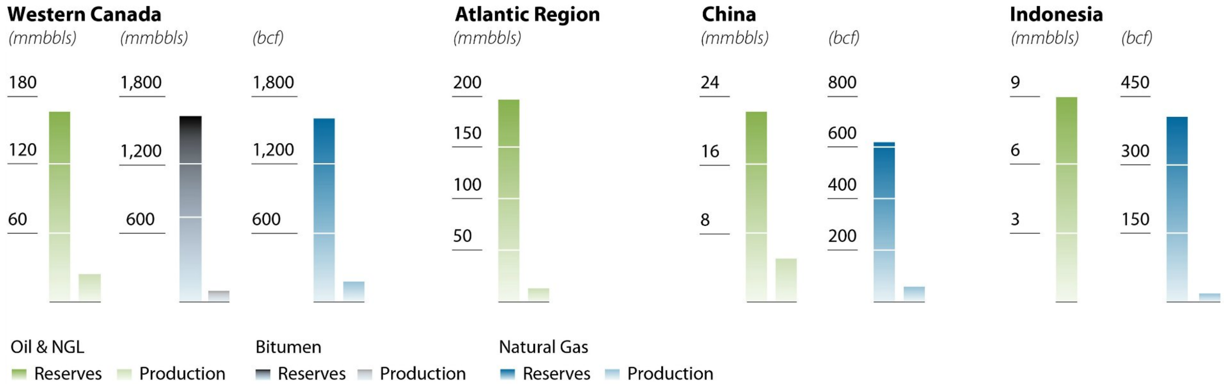
The Company's complete oil and gas reserves disclosure, prepared in accordance with NI 51-101 is contained in the Company's Annual Information Form, which is available at www.sedar.com, and certain supplementary oil and gas reserves disclosure prepared in accordance with U.S. disclosure requirements is contained in the Company's Form 40-F, which is available at www.sec.gov or on the Company's website at www.huskyenergy.com.

Sproule Associates Ltd. ("Sproule"), an independent firm of qualified oil and gas reserves evaluation engineers, was engaged to conduct an audit of the Company's crude oil, natural gas and NGL reserves estimates. Sproule issued an audit opinion on January 31, 2018. stating that the Company's internally generated proved and probable reserves and net present values based on forecast and constant price assumptions are, in aggregate, reasonable and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices as set out in the Canadian Oil and Gas Evaluation Handbook.

At December 31, 2017, the Company's proved oil and gas reserves were 1,301 mmboe, compared to 1,224 mmboe at the end of 2016. The Company's 2017 reserves replacement ratio, defined as net additions divided by total production during the period, was 167 percent excluding economic revisions (165 percent including economic revisions). The 2017 reserves replacement ratio, excluding disposition/acquisition and economic factors, was 219 percent (217 percent including economic factors). Major changes to proved reserves in 2017 included:

- The disposition of Western Canada assets resulted in a total divestiture of 62 mmboe.
- Extensions and improved recovery additions of 220 mmbbls including 109 mmbbls for three new Lloyd thermal bitumen SAGD projects, 65 mmbbls with the sanctioning of the West White Rose Project, 27 mmbbls at the Sunrise Energy Project from new locations, and 14 mmboe in Ansell from new locations.
- Technical revisions of 36 mmboe including 12 mmboe in China due to strong gas performance, 20 mmbbls from improved CHOPS performance and Lloyd thermal bitumen performance additions of 3 mmbbls offset by negative performance of 6 mmboe for wells or facilities close to the end of their economic lives.

Proved Plus Probable Reserves and Production at December 31, 2017:



Reconciliation of Proved Reserves

	Canada					International		Total		
	Western Canada				Atlantic					
(forecast prices and costs before royalties)	Light/ Medium Crude Oil & NGL *(mmbbls)*	Heavy Crude Oil *(mmbbls)* [1]	Bitumen *(mmbbls)*[1]	Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Crude Oil, Bitumen & NGL *(mmbbls)*	Natural Gas *(bcf)*	Equivalent Units *(mmboe)*
Proved reserves										
December 31, 2016	79	63	648	1,517	47	23	668	860	2,185	1,224
Technical revisions	4	17	6	—	(3)	3	53	27	53	36
Acquisitions	—	—	—	1	—	—	—	—	1	—
Dispositions	(12)	(1)	—	(294)	—	—	—	(13)	(294)	(62)
Discoveries, extensions and improved recovery	3	1	137	97	65	—	—	206	97	222
Economic factors	—	—	—	(9)	—	—	—	—	(9)	(2)
Production	(8)	(16)	(44)	(138)	(12)	(5)	(59)	(85)	(197)	(118)
Proved reserves December 31, 2017	**66**	**64**	**747**	**1,174**	**97**	**21**	**662**	**995**	**1,836**	**1,301**
Proved and probable reserves December 31, 2017	**80**	**86**	**1,609**	**1,597**	**196**	**31**	**1,014**	**2,002**	**2,611**	**2,437**
December 31, 2016	95	83	1,923	1,940	207	29	926	2,337	2,866	2,815

(1) *Lloydminster thermal property reserves are classified as bitumen.*

Reconciliation of Proved Developed Reserves

	Canada					International		Total		
	Western Canada				Atlantic					
(forecast prices and costs before royalties)	Light/ Medium Crude Oil & NGL *(mmbbls)*	Heavy Crude Oil *(mmbbls)* [1]	Bitumen *(mmbbls)*[1]	Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Crude Oil, Bitumen & NGL *(mmbbls)*	Natural Gas *(bcf)*	Equivalent Units *(mmboe)*
Proved developed reserves										
December 31, 2016	75	63	160	1,183	42	23	567	363	1,750	654
Technical revisions	4	18	6	—	(2)	3	53	29	53	38
Transfer from proved undeveloped	1	—	40	55	5	—	—	46	55	55
Acquisitions	—	—	—	1	—	—	—	—	1	—
Dispositions	(12)	(1)	—	(294)	—	—	—	(13)	(294)	(62)
Discoveries, extensions and improved recovery	2	—	—	25	4	—	—	6	25	10
Economic factors	—	—	—	(9)	—	—	—	—	(9)	(2)
Production	(8)	(16)	(44)	(138)	(12)	(5)	(59)	(85)	(197)	(118)
December 31, 2017	**62**	**64**	**162**	**823**	**37**	**21**	**561**	**346**	**1,384**	**575**

(1) *Lloydminster thermal property reserves are classified as bitumen.*

Infrastructure and Marketing

Infrastructure and Marketing Earnings Summary *($ millions, except where indicated)*	**2017**	2016
Gross revenues	**1,976**	955
Purchases of crude oil and products	**1,855**	857
Infrastructure gross margin	**121**	98
Marketing and other	**(40)**	(88)
Total Infrastructure and Marketing gross margin	**81**	10
Production, operating and transportation expenses	**13**	20
Selling, general and administrative expenses	**4**	5
Depletion, depreciation, amortization and impairment	**2**	13
Loss (gain) on sale of assets	**1**	(1,439)
Other – net	**(8)**	(3)
Share of equity investment gain	**(49)**	(16)
Provisions for income taxes	**32**	122
Net earnings	**86**	1,308

Infrastructure and Marketing gross revenues and purchases of crude oil products increased by $1,021 million and $998 million, respectively, in 2017 compared to 2016, primarily due to increased volumes and prices.

Marketing and other loss decreased by $48 million in 2017 compared to 2016 primarily due to crude oil marketing gains from widening price differentials between Canada and the U.S. during 2017. This was partially offset by unrealized crude oil mark-to-market losses as a result of falling forward heavy differentials towards the end of 2017.

The Company recorded a loss on sale of assets of $1 million in 2017 compared to a gain of $1,439 million in 2016. The gain on sale of assets in 2016 was due to the sale of ownership interest in select midstream assets.

Share of equity investment gain increased by $33 million in 2017 compared to 2016 due to the pipeline spill costs incurred in 2016 and the formation of HMLP in mid-2016. Refer to Note 11 of the Consolidated Financial Statements.

Provisions for income taxes decreased by $90 million in 2017 compared to 2016 due to the tax associated with the sale of ownership interest in select midstream assets in 2016.

4.3 Downstream

Upgrading

Upgrading Earnings Summary *($ millions, except where indicated)*	**2017**	2016
Gross revenues	**1,440**	1,324
Purchases of crude oil and products	**983**	808
Gross margin	**457**	516
Production, operating and transportation expenses	**197**	168
Selling, general and administrative expenses	**9**	4
Depletion, depreciation, amortization and impairment	**99**	103
Other – net	**—**	(1)
Financial items	**1**	1
Provisions for income taxes	**41**	66
Net earnings	**110**	175
Upgrading throughput *(mbbls/day)*[(1)]	**68.5**	72.5
Total sales *(mbbls/day)*	**68.5**	72.8
Synthetic crude oil sales *(mbbls/day)*	**49.8**	55.2
Upgrading differential *($/bbl)*	**18.66**	20.74
Unit margin *($/bbl)*	**18.28**	19.37
Unit operating cost *($/bbl)*[(2)]	**7.88**	6.33

(1) *Throughput includes diluent returned to the field.*
(2) *Based on throughput.*

The Upgrading operations add value by processing heavy crude oil into high value synthetic crude oil and low sulphur distillates. The Upgrading profitability is primarily dependent on the differential between the cost of heavy crude oil feedstock and the sales price of synthetic crude oil.

Gross revenues increased by $116 million in 2017 compared to 2016 primarily due to higher realized prices for synthetic crude oil, partially offset by lower sales volumes resulting from a planned major turnaround in the second quarter of 2017. The price of Husky Synthetic Blend averaged $67.05/bbl in 2017 compared to $57.54/bbl in 2016. Sales volumes decreased by 4.3 mbbls/day, or five percent, and throughput decreased by 4.0 mbbls/day, or six percent, compared to 2016 due to the planned major turnaround in 2017.

Upgrading feedstock purchases increased by $175 million in 2017 compared to 2016 primarily due to higher Lloyd Heavy Blend pricing, which averaged $48.39/bbl in 2017 compared to $36.79/bbl in 2016.

Gross margin decreased by $59 million in 2017 compared to 2016 primarily due to the tightening light/heavy differentials, lowering the average upgrading differentials in 2017. The upgrading differential averaged $18.66/bbl in 2017, a decrease of $2.08/bbl or 10 percent compared to 2016. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend.

Production, operating and transportation expenses increased by $29 million in 2017 compared to 2016 primarily due to higher maintenance, labour and energy costs related to the planned major turnaround in the second quarter of 2017.

Provisions for income taxes decreased by $25 million in 2017 compared to 2016 primarily due to lower earnings before income taxes in 2017.

Canadian Refined Products

Canadian Refined Products Earnings Summary *($ millions, except where indicated)*	2017	2016
Gross revenues	**2,787**	2,301
Purchases of crude oil and products	**2,219**	1,770
Gross margin	**568**	531
Fuel	**139**	136
Refining	**174**	123
Asphalt	**201**	217
Ancillary	**54**	55
	568	531
Production, operating and transportation expenses	**256**	241
Selling, general and administrative expenses	**53**	43
Depletion, depreciation, amortization and impairment	**111**	102
Gain on sale of assets	**(5)**	(3)
Other – net	**(1)**	(10)
Financial items	**12**	7
Provisions for income taxes	**38**	41
Net earnings	**104**	110
Number of fuel outlets(1)	**518**	481
Fuel sales volume, including wholesale		
Fuel sales *(millions of litres/day)*	**7.3**	6.6
Fuel sales per outlet *(thousands of litres/day)*	**12.1**	11.8
Refinery throughput		
Prince George Refinery *(mbbls/day)*	**11.2**	9.4
Lloydminster Refinery *(mbbls/day)*	**26.8**	27.8
Ethanol production *(thousands of litres/day)*	**804.8**	820.6

(1) *Average number of fuel outlets for period indicated.*

Canadian Refined Products gross revenues increased by $486 million in 2017 compared to 2016 primarily due to higher commodity pricing, and higher sales volumes at the Prince George Refinery, where a major planned turnaround was completed in 2016. The increase was partially offset by lower throughput volumes at the Lloydminster Refinery, due to a planned turnaround in the second quarter of 2017, and lower asphalt margins due to market oversupply related to weather delays.

Purchases of crude oil and products increased by $449 million in 2017 compared to 2016 primarily due to higher commodity pricing, partially offset by the lower volumes at the Lloydminster Refinery due to a planned turnaround in the second quarter of 2017.

Refining gross margins increased by $51 million in 2017 compared to 2016 primarily due to higher sales volumes at the Prince George Refinery and the Minnedosa Ethanol Plant combined with higher ethanol pricing.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary *($ millions, except where indicated)*	**2017**	2016
Gross revenues	**9,355**	5,995
Purchases of crude oil and products	**8,059**	5,188
Gross margin	**1,296**	807
Production, operating and transportation expenses	**563**	535
Selling, general and administrative expenses	**15**	13
Depletion, depreciation, amortization and impairment	**354**	342
Other – net	**(21)**	(176)
Financial items	**14**	3
Provisions for income taxes	**137**	33
Net earnings	**234**	57
Selected operating data:		
Lima Refinery throughput *(mbbls/day)*	**172.2**	138.2
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**76.6**	62.2
Superior Refinery throughput *(mbbls/day)*(1)	**5.5**	—
Refining margin *(US$/bbl crude throughput)*	**11.09**	8.94
Refinery inventory *(mmbbls)*(2)	**9.2**	10.8

(1) *The Superior Refinery was acquired on November 8, 2017.*
(2) *Feedstock and refined products are included in refinery inventory.*

U.S. Refining and Marketing gross revenues increased by $3,360 million in 2017 compared to 2016. The increase was primarily due to the higher finished goods sales prices and higher sales volume as a result of stronger operations in 2017, and scheduled major turnarounds at both the Lima and BP-Husky Toledo Refineries in 2016.

Purchases of crude oil and products increased by $2,871 million in 2017 compared to 2016 primarily due to higher crude oil feedstock costs and increased throughput at both the Lima and BP-Husky Toledo refineries. Throughput increased at the Lima Refinery by 34.0 mbbls/day and at the BP-Husky Toledo Refinery by 14.4 mbbls/day compared to 2016 primarily due to the planned major turnarounds at both the Lima and BP-Husky Toledo refineries in 2016 and the isocracker at Lima being fully in service in 2017.

Gross margin increased by $489 million in 2017 compared to 2016 primarily due to a higher Chicago 3:2:1 crack spread and higher sales volumes.

Other – net income decreased by $155 million in 2017 compared to 2016 primarily due to reduced insurance recoveries associated with the isocracker unit fire in 2016.

Provisions for income taxes increased by $104 million in 2017 compared to 2016 primarily due to higher earnings before income taxes in 2017.

The Chicago 3:2:1 crack spread benchmark is based on LIFO accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI, while crude oil feedstock costs included in realized margins are based on FIFO accounting, which reflects purchases made in previous months. The estimated FIFO impact was an increase in net earnings of approximately $58 million in 2017 compared to an increase of $50 million in 2016.

Downstream Capital Expenditures

In 2017, Downstream capital expenditures totalled $630 million compared to $726 million in 2016. The decrease in Downstream capital expenditures was primarily due to the completion of major planned turnarounds at the Lima and BP-Husky Toledo refineries and the feedstock optimization project in U.S. Refining and Marketing in 2016.

In Canada, capital expenditures of $317 million were primarily related to the scheduled major turnarounds at the Lloydminster Upgrader and Lloydminster Refinery in the second quarter of 2017.

In the U.S., capital expenditures of $313 million were primarily related to the crude oil flexibility project and various reliability, safety and environmental protection initiatives at the Lima Refinery. Capital expenditures of $95 million at the BP-Husky Toledo Refinery (Husky working interest) were primarily related to reliability, safety and environmental protection initiatives.

4.4 Corporate

Corporate Summary *($ millions) income (expense)*	**2017**	2016
Selling, general and administrative expenses	**(304)**	(247)
Depletion, depreciation, amortization and impairment	**(79)**	(87)
Other – net	**(6)**	(110)
Net foreign exchange gain (loss)	**(6)**	13
Finance income	**32**	12
Finance expense	**(234)**	(245)
Recovery of income taxes	**675**	153
Net earnings (loss)	**78**	(511)

The Corporate segment reported net earnings of $78 million in 2017 compared to a net loss of $511 million in 2016. Recovery of income taxes increased primarily due to the recognition of $436 million in deferred tax recovery related to the reduction in the U.S. Federal corporate tax rate that will take effect in 2018. Selling, general and administrative expenses increased by $57 million in 2017 primarily due to increases in employee costs and stock-based compensation expenses. Other – net expense decreased by $104 million in 2017 relates primarily to losses on the Company's short-term hedging program which concluded in June 2016. Finance income increased by $20 million primarily due to interest on short-term investments. Net foreign exchange gain (loss) decreased by $19 million due to the items noted below.

Foreign Exchange Summary *($ millions, except exchange rate amounts)*	**2017**	2016
Non-cash working capital gain (loss)	**(3)**	4
Other foreign exchange gain (loss)	**(3)**	9
Net foreign exchange gain (loss)	**(6)**	13
U.S./Canadian dollar exchange rates:		
At beginning of year	**US$0.745**	US$0.723
At end of year	**US$0.799**	US$0.745

Included in other foreign exchange gain (loss) are realized and unrealized foreign exchange gains and losses on working capital and intercompany financing. The foreign exchange gains and losses on these items can vary significantly due to the large volume and timing of transactions through these accounts in the period. The Company manages its exposure to foreign currency fluctuations in order to minimize the impact of foreign exchange gains and losses on the Consolidated Financial Statements.

Consolidated Income Taxes

Consolidated Income Taxes *($ millions)*	**2017**	2016
Provisions for (recovery of) income taxes	**(362)**	28
Cash income taxes received	**(41)**	(3)

Consolidated income taxes were a recovery of $362 million in 2017 compared to an income tax expense of $28 million in 2016. The recovery of consolidated income taxes was primarily due to the recognition of $436 million in deferred tax recovery related to the reduction in the U.S. Federal corporate tax rate that will take effect in 2018.

5.0 Risk and Risk Management

5.1 Enterprise Risk Management

The Company's enterprise risk management program supports decision-making via comprehensive and systematic identification and assessment of risks that could materially impact the results of the Company. Through this framework, the Company builds risk management and mitigation into strategic planning and operational processes for its business units through the adoption of standards and best practices. The Company has developed an enterprise risk matrix to identify risks to its people, the environment, its assets and its reputation, and to systematically mitigate these risks to an acceptable level.

The Company attempts to mitigate its financial, operational and strategic risks to an acceptable level through a variety of policies, systems and processes. The following provides a list of the most significant risks relating to the Company and its operations.

5.2 Significant Risk Factors

Operational, Environmental and Safety Incidents

The Company's businesses are subject to inherent operational risks with respect to safety and the environment that require continuous vigilance. The Company seeks to minimize these operational risks by carefully designing and building its facilities and conducting its operations in a safe and reliable manner using Husky Operational Integrity Management System, its integrated management system that considers environmental requirements and process and occupational safety. Failure to manage the risks effectively could result in potential fatalities, serious injury, interruptions to activities or use of assets, damage to assets, environmental impact or loss of licence to operate. Enterprise risk management, emergency preparedness, business continuity and security policies and programs are in place for all operating areas and are adhered to on an ongoing basis. The Company, in accordance with industry practice, maintains insurance coverage against losses from certain of these risks. Nonetheless, insurance proceeds may not be sufficient to cover all losses, and insurance coverage may not be available for all types of operational risks.

Commodity Price Volatility

The Company's results of operations and financial condition are dependent on the prices received for its refined products, crude oil, NGL and natural gas production. Lower prices for crude oil, NGL and natural gas could adversely affect the value and quantity of the Company's oil and gas reserves. The Company's reserves include significant quantities of heavier grades of crude oil that trade at a discount to light crude oil. Heavier grades of crude oil are typically more expensive to produce, process, transport and refine into high value refined products. Refining and transportation capacity for heavy crude oil and bitumen is limited and planned increases of North American heavy crude oil and bitumen production may create the need for additional heavy oil and bitumen refining and transportation capacity. Wider price differentials between heavier and lighter grades of crude oil could have a material adverse effect on the Company's results of operations and financial condition, reduce the value and quantities of the Company's heavier crude oil reserves and delay or cancel projects that involve the development of heavier crude oil resources. There is no guarantee that pipeline development projects will provide sufficient transportation capacity and access to refining capacity to accommodate expected increases in North American heavy crude oil and bitumen production.

Prices for refined products and crude oil are based on world supply and demand. Supply and demand can be affected by a number of factors including, but not limited to, actions taken by OPEC, non-OPEC crude oil supply, social conditions in oil producing countries, the occurrence of natural disasters, general and specific economic conditions, technological developments, prevailing weather patterns, government regulation and policies and the availability of alternate sources of energy.

The Company's natural gas production is currently located in Western Canada and Asia Pacific. Western Canada's natural gas production is subject to North American market forces. North American natural gas supply and demand is affected by a number of factors including, but not limited to, the amount of natural gas available to specific market areas either from the well head of existing or accessible conventional or unconventional sources (such as from shale), or from storage facilities, technological developments, prevailing weather patterns, the U.S. and Canadian economies, the occurrence of natural disasters and pipeline restrictions.

In certain instances, the Company will use derivative instruments to manage exposure to price volatility on a portion of its refined product, oil and gas production, inventory or volumes in long-distance transit. The Company may also use firm commitments for the purchase or sale of crude oil and natural gas.

The fluctuations in refined products, crude oil and natural gas prices are beyond the Company's control and could have a material adverse effect on the Company's results of operations and financial condition.

Reservoir Performance Risk

Lower than projected reservoir performance on the Company's key growth projects could have a material adverse effect on the Company's results of operations, financial condition, business strategy and reserves. Inaccurate appraisal of large project reservoirs could result in missed production, revenue and earnings targets and negatively affect the Company's reputation, investor confidence and the Company's ability to deliver on its growth strategy.

In order to maintain the Company's future production of crude oil, natural gas and NGL and maintain the value of the reserves portfolio, additional reserves must be added through discoveries, extensions, improved recovery, performance related revisions and acquisitions. The production rate of oil and gas properties tends to decline as reserves are depleted while the associated unit operating costs increase. In order to mitigate the effects of this, the Company must undertake successful exploration and development programs, increase the recovery factor from existing properties through applied technology and identify and execute strategic acquisitions of proved developed and undeveloped properties and unproved prospects. Maintaining an inventory of projects that can be developed depends upon, but is not limited to, obtaining and renewing rights to explore, develop and produce oil and natural gas, drilling success, completion of long lead time capital intensive projects on budget and on schedule and the application of successful exploitation techniques on mature properties.

Restricted Market Access and Pipeline Interruptions

The Company's results depend upon the Company's ability to deliver products to the most attractive markets. The Company's results of operations could be materially adversely affected by restricted market access resulting from a lack of pipeline or other transportation alternatives to attractive markets as well as regulatory and/or other marketplace barriers. Interruptions and restrictions may be caused by the inability of a pipeline to operate, or they can be related to capacity constraints as the supply of feedstock into the system exceeds the infrastructure capacity. With growing oil production across North America and the limited availability of infrastructure to carry the Company's products to the marketplace, oil and natural gas transportation capacity is expected to be restricted in the next few years. Restricted market access may potentially have a material adverse effect on the Company's results of operations, financial condition and business strategy. Unplanned shutdowns and closures of its refineries or Upgrader may limit the Company's ability to deliver product with a material adverse effect on sales and results of operations.

Security and Terrorist Threats

Security threats and terrorist or activist activities may impact the Company's personnel, which could result in injury, death, extortion, hostage situations and/or kidnapping, including unlawful confinement. A security threat, terrorist attack or activist incident targeted at a facility, office or offshore vessel/installation owned or operated by the Company could result in the interruption or cessation of key elements of the Company's operations. Outcomes of such incidents could have a material adverse effect on the Company's results of operations, financial condition and business strategy.

International Operations

International operations can expose the Company to uncertain political, economic and other risks. The Company's operations in certain jurisdictions may be materially adversely affected by political, economic or social instability or events. These events may include, but are not limited to, onerous fiscal policy, renegotiation or nullification of agreements and treaties, imposition of onerous regulation, changes in laws governing existing operations, financial constraints, including currency restrictions and exchange rate fluctuations, unreasonable taxation and behaviour of public officials, joint venture partners or third-party representatives that could result in lost business opportunities for the Company. This could materially adversely affect the Company's interest in its foreign operations, results of operations and financial condition.

Major Project Execution

The Company manages a variety of oil and gas projects ranging from Upstream to Downstream assets. The risks associated with project development and execution include, among others, the Company's ability to obtain necessary environmental and regulatory approvals. This may result in extended stakeholder consultation, environmental assessments and public hearings. Additionally, there are risks involved with commissioning and integration of new assets to existing facilities. All of these and other risks can impact the economic feasibility of the Company's projects. Project risks can manifest through cost overruns, schedule delays and commodity price decreases. Some project risks can impact the Company's safety and environmental records thereby negatively affecting the Company's reputation.

Litigation, Administrative Proceedings and Regulatory Actions

The Company may be subject to litigation, claims, administrative proceedings and regulatory actions, which may be material. Such claims could relate to environmental damage, failure to comply with applicable laws and regulations, breach of contract, tax, bribery and employment matters, which could result in an unfavourable decision, including fines, sanctions, monetary damages, temporary suspensions of operations or the inability to engage in certain operations or transactions. The outcome of such claims can be difficult to assess or quantify and may have a material adverse effect on the Company's reputation, financial condition and results of operations. The defence to such claims may be costly and could divert management's attention away from day-to-day operations.

Partner Misalignment

Joint venture partners operate a portion of the Company's assets in which the Company has an ownership interest. This can reduce the Company's control and ability to manage risks. The Company is at times dependent upon its partners for the successful execution of various projects. If a dispute with partners were to occur over the development and operation of a project or if partners were unable to fund their contractual share of the capital expenditures, a project could be delayed and the Company could be partially or totally liable for its partner's share of the project.

Reserves Data, Future Net Revenue and Resource Estimates

The reserves data contained or referenced in the MD&A represent estimates only. The accurate assessment of oil and gas reserves is critical to the continuous and effective management of the Company's Upstream assets. Reserves estimates support various investment decisions about the development and management of oil and gas properties. In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flow therefrom are based upon a number of variable factors and assumptions, such as product prices, future operating and capital costs, historical production from the properties and the effects of regulation by government agencies, including with respect to royalty payments, all of which may vary considerably from actual results. The Company uses all available information at the effective date of the evaluation and qualified reserves evaluators to prepare the reserves estimates. The Company also has a number of quality control measures in its reserves process including seeking the opinion of an independent reserves auditor on the Company's reserves. However, given the best technical information and evaluation techniques, all such estimates are still to some degree uncertain. All reserves estimates involve a degree of ambiguity and, at times, rely on indirect measurement techniques to estimate the size and recoverability of the resource. While new technologies have increased the accuracy of these techniques, there remains the potential for human or systemic error in recording and reporting the magnitude of the Company's oil and gas reserves. Estimates of the economically recoverable oil and gas reserves attributable to any particular property or group of properties, and estimates of future net revenues expected therefrom, may differ substantially from actual results even though the total company reserves are shown to be reliable through the historical total company technical reserves revisions. The Company has a diverse portfolio of assets by product type, reservoir type and location which is a factor in mitigating specific property risks. Inaccurate appraisal of large project reservoirs could result in missed production, revenue and earnings targets and could have a material adverse effect on the Company's reputation, investor confidence and ability to deliver on its growth business strategy.

Government Regulation

Given the scope and complexity of the Company's operations, the Company is subject to regulation and intervention by governments at the federal, provincial, state and municipal levels in the countries in which it conducts its operations, development or exploratory activities. As these governments continually balance competing demands from different interest groups and stakeholders, the Company recognizes that the magnitude of regulatory risks has the potential to change over time. Changes in government policy, legislation or regulation could impact the Company's existing and planned projects as well as impose costs of compliance and increase capital expenditures and operating expenses. Examples of the Company's regulatory risks include, but are not limited to, uncertain or negative interactions with governments, uncertain energy policies, uncertain climate policies, uncertain environmental and safety policies, penalties, taxes, royalties, government fees, reserves access, limitations or increases in costs relating to the exportation of commodities, restrictions on the acquisition of exploration and production rights and land tenure, expropriation or cancellation of contract rights, limitations on control over the development and abandonment of fields and loss of licences to operate.

Environmental Regulation

Changes in environmental regulation could have a material adverse effect on the Company's results of operations, financial condition and business strategy by requiring increased capital expenditures and operating costs or by impacting the quality, formulation or demand of products, which may or may not be offset through market pricing.

The Company anticipates further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liabilities, increased compliance costs and approval delays for critical licences and permits, which could have a material adverse effect on the Company's results of operations, financial condition and business strategy through increased capital and operating costs.

Climate Change Regulation

Climate change regulations may become more onerous over time as governments implement policies to further reduce greenhouse gases ("GHG") emissions. As part of long range planning, the Company assesses future costs associated with regulation of GHG emissions in its operations and the evaluation of future projects, based on the Company's outlook for carbon pricing under current and pending regulations. Although the impact of emerging regulations is uncertain, they could have a material adverse effect on the Company's financial condition and results of operation through increased capital and operating costs and change in demand for refined products such as transportation fuels. The Company continues to monitor international and domestic efforts to address climate change, including international low carbon fuel standards and regulations and other emerging regulations in the jurisdictions in which the Company operates.

The Alberta Climate Leadership Plan began to be implemented in 2017. This plan includes an economy-wide carbon levy, rising to $30 per tonne in 2018 which applies to the Lloydminster Refinery as well as a Carbon Competitiveness Incentive Regulation ("CCIR") that will manage emissions at large final emitting facilities ("LFEs") including the Tucker Thermal Project and Sunrise Energy Project. Under the Specified Gas Emitters Regulation, which expired at the end of 2017, the Tucker Thermal Project generated over 250,000 tonnes of credits due to improved emission intensity performance. These credits are eligible to offset future compliance obligations under the CCIR. These regulations are not anticipated to have a material impact over the duration of the Company's five year long range plan. The CCIR is due for review in 2020, along with the federal "backstop". Uncertainty regarding future regulation, including carbon price and the details of implementing the oil sands emission limit, make it difficult to predict the potential future impact on the Company.

Saskatchewan's "Prairie Resilience" policy paper, released in December 2017, includes a number of proposals related to climate change including a performance standard for facilities which emit over 25kt of carbon dioxide equivalent each year. This would include the Company's Lloydminster Upgrader, ethanol plant and thermal projects. Climate change regulations are expected to be developed in 2018 and may materially adversely affect the Company's results of operations in the province. The impact on the Company is unknown at this time.

The cost of compliance with British Columbia's $30 per tonne carbon tax (increasing to $35 per tonne on April 1, 2018) and the Renewable and Low Carbon Fuel Requirements Regulation may materially adversely affect the Company's Prince George Refinery. Additionally, future regulations in support of British Columbia's commitment under its Climate Leadership Plan are uncertain.

Consultation continues regarding Manitoba's Climate and Green Plan with implementation expected in 2018. Resulting regulations are not yet certain but may materially adversely affect the Company's Minnedosa ethanol plant in Manitoba

Climate change regulations for the NL offshore are currently being developed as part of a consultation process involving the four offshore operators via Canadian Association of Petroleum Producers ("CAPP"). These regulations will have to meet equivalency standards with the Government of Canada. The details of the regulations are not yet known, and so the impact on the Company's operations offshore of NL is uncertain. Note that the Government of NL currently has no jurisdiction to regulate offshore GHG emissions, but discussions are underway to amend the Atlantic Accord to give NL jurisdiction to regulate offshore GHG emissions.

Within the mandate of the Pan-Canadian Framework on Clean Growth and Climate Change, in May 2017, the Government of Canada released a technical paper on the federal Carbon Pricing Backstop introducing two key elements: a carbon levy applied to gas that the Company uses at its facilities as well as retail fuel ($10 per tonne starting in 2018 and increasing by $10 annually to $50 per tonne in 2022), and an output-based pricing system for industrial facilities emitting GHGs above 50 kt per year. A federal Clean Fuel Standard Discussion Paper was also released in 2017. The impact of the Clean Fuel Standard is still uncertain.

The Company's U.S. refining business may be materially adversely affected by the implementation of the Environmental Protection Agency's ("EPA") climate change rules or, by future U.S. GHG legislation that applies to the oil and gas industry or the consumption of petroleum products and by other U.S. climate change statutes at the federal or state level or by regulations imposed by other federal agencies or at the state or local level. Such legislation or regulation could require the Company's U.S. refining operations to significantly reduce emissions and/or purchase emission credits, thereby increasing operating and capital costs, and could change the demand for refined products which may have a material adverse effect on the Company's financial condition and results of operation.

The U.S. Renewable Fuel Standard ("RFS") program, through the U.S. EPA specified renewable volume obligation ("RVO"), requires refiners to add annually increasing amounts of renewable fuels to their petroleum products or to purchase RINs in lieu of such blending. Due to regulatory uncertainty and in part due to the U.S. fuel supply reaching the "blend wall" (the 10 percent limit prescribed by most automobile warranties), the price and availability of RINs has been volatile.

The Company complies with the RFS program in the U.S. by blending renewable fuels manufactured by third parties and by purchasing RINs on the open market. The Company cannot predict the future prices of RINs and renewable fuel blendstocks, and the costs to obtain the necessary RINs and blendstocks could be material. The Company's financial position and results of operations could be adversely affected if it is unable to pass the costs of compliance on to its customers and if the Company pays significantly higher prices for RINs or blendstocks to comply with the RFS mandated standards.

Competition

The energy industry is highly competitive with respect to gaining access to the resources required to increase oil and gas reserves and production, and gaining access to markets. The Company competes with others to acquire prospective lands, retain drilling capacity and field operating and construction services, obtain sufficient pipeline and other transportation capacity, gain access to and retain adequate markets for its products and services and gain access to capital markets. The Company's ability to successfully complete development projects could be materially adversely affected if it is unable to acquire economic supplies and services due to competition. Subsequent increases in the cost of or delays in acquiring supplies and services could result in uneconomic projects. The Company's competitors comprise all types of energy companies, some of which have greater resources.

General Economic Conditions

General economic conditions may have a material adverse effect on the Company's results of operations and financial condition. A decline in economic activity will reduce demand for petroleum products and adversely affect the price the Company receives for its commodities. The Company's cash flow could decline, assets could be impaired, future access to capital could be restricted and major development projects could be delayed or abandoned.

Cost or Availability of Oil and Gas Field Equipment

The cost or availability of oil and gas field equipment may adversely affect the Company's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services and construction materials. These materials and services may not be available when required at reasonable prices. Without compromising safety, overall quality and environmental impacts, the Company continually develops its approved suppliers base to provide undisrupted access to materials, equipment and services, while maintaining a competitive cost baseline via cost escalation mitigation strategies.

Climatic Conditions

Extreme climatic conditions may have material adverse effects on financial condition and results of operations. Weather and climate affect demand, and therefore, the predictability of the demand for energy is affected to a large degree by the predictability of weather and climate. In addition, the Company's exploration, production and construction operations, and the operations of major customers and suppliers, can be affected by extreme weather. This may result in cessation or diminishment of production, delay of exploration and development activities or delay of plant construction.

The Company operates in some of the harshest environments in the world, including offshore in Atlantic. Climate change may increase the frequency of severe weather conditions in these locations including winds, flooding and variable temperatures, which are contributing to the melting of northern ice and increased creation of icebergs. Icebergs off the coast of NL may threaten offshore oil production facilities, cause damage to equipment and possible production disruptions, spills, asset damage and human impacts. The Company has in place a number of policies to protect people, equipment and the environment in the event of extreme weather conditions and ice melt conditions.

The Company's Atlantic operations has a robust ice management program, which uses a range of resources including a dedicated ice surveillance aircraft, as well as synergistic relationships with government agencies including Environment and Climate Change Canada, the Coast Guard and Canadian Ice Service. Regular ice surveillance flights commence in February and continue until the risk has abated. In addition, Atlantic operators employ a series of supply and support vessels to actively manage ice and icebergs. These vessels are equipped with a variety of ice management tools including towing ropes, towing nets and water cannons. The Company also maintains a series of ad-hoc relationships with contractors, allowing the quick mobilization of additional resources as required. The Company regularly assesses all aspects of its ice management program in order to ensure that the program continues to evolve as more information about the characteristics of ice and icebergs in the Atlantic becomes available and as new technologies are developed.

Financial Controls

While the Company has determined that its disclosure controls and procedures and internal controls over financial reporting are effective, such controls can only provide reasonable assurance with respect to financial statement preparation and disclosure. Failure to prevent, detect and correct misstatements could have a material adverse effect on the Company's results of operations and financial condition.

Cybersecurity Threats

As an oil and gas producer, the Company's ability to operate effectively is dependent upon developing and maintaining information systems and infrastructure that support the financial and general operating aspects of the business. Concurrently, the oil and gas industry has become the subject of increased levels of cybersecurity threats.

The Company has security measures, policies and controls designed to protect and secure the integrity of its information technology systems. The Company takes a proactive approach by continuing to invest in technology, processes and people to help minimize the impact of the changing cyber landscape and enhance the Company's resilience to cyber incidents. However, cybersecurity threats frequently change and require ongoing monitoring and detection capabilities. Such cybersecurity threats include unauthorized access to information technology systems due to hacking, viruses and other causes for purposes of misappropriating assets or sensitive information, corrupting data or causing operational disruption. Cyber-attacks could result in the loss or exposure of confidential information related to retail credit card information, personnel files, exploration activities, corporate actions, executive officer communications and financial results. The significance of any such event is difficult to quantify, but if the breach is material in nature, it could adversely affect the financial performance of the Company, its operations, its reputation and standing and expose it to regulatory consequences and claims of third-party damage, all of which could materially adversely affect the Company's results of operations and financial condition if the situation is not resolved in a timely manner, or if the financial impact of such adverse effects is not alleviated through insurance policies.

Although to date the Company has not experienced any material losses relating to cyber attacks or other information security breaches, there can be no assurance that the Company will not incur such losses in the future. The Company's risk and exposure to these matters cannot be fully mitigated because of, among other things, the evolving nature of these threats. The Audit Committee of the Company's Board of Directors has oversight of the Company's risk mitigation strategies related to cybersecurity.

Skilled Workforce Shortage

Successful execution of the Company's strategy is dependent on ensuring the Company's workforce possesses the appropriate skill level. There is a risk that the Company may have difficulty attracting and retaining personnel with the required skill levels. Failure to attract and retain personnel with the required skill levels could have a material adverse effect on the Company's financial condition and results of operations.

Aviation Incidents

The Company's offshore operations in Canada and China rely on regular travel by helicopter. There is a risk of a helicopter crash due to mechanical failure or human error resulting in a significant safety incident and subsequent facility shutdown and regulatory action. This risk is mitigated through a robust management process, maintenance program and regular auditing of Husky's aviation service providers. Helicopters chartered to support Husky offshore operations are designed to adapt to the anticipated environmental challenges i.e., anti-icing and floatation systems aligned to maximum sea height limits. Helicopters are also fitted with multiple redundant systems to address a wide range of in-flight emergencies. Pilots are trained to address these situations through regular real-time and simulator training aligned with and surpassing industry best practice.

5.3 Financial Risks

The Company's financial risks are largely related to commodity price risk, foreign currency risk, interest rate risk, counterparty credit risk and liquidity risk. From time to time, the Company uses derivative financial instruments to manage its exposure to these risks. These derivative financial instruments are not intended for trading or speculative purposes.

Fair Value of Financial Instruments

The Company's financial assets and liabilities that are recorded at fair value on a recurring basis have been categorized into one of three categories based upon the fair value hierarchy. Level 1 fair value measurements are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair value measurements of assets and liabilities in Level 2 include valuations using inputs other than quoted prices but for which all significant outputs are observable, either directly or indirectly. Level 3 fair value measurements are based on inputs that are unobservable and significant to the overall fair value measurement.

The Company's financial instruments include cash and cash equivalents, accounts receivable, restricted cash, accounts payable and accrued liabilities, short-term debt, long-term debt, contribution payable, derivatives, portions of other assets and other long-term liabilities.

For the year ended December 31, 2017, the Company recognized a $46 million unrealized loss on its crude oil and natural gas risk management positions which was recorded in marketing and other. In addition, the Company recognized a $30 million realized loss recorded in net foreign currency forwards. Refer to Note 24 to the 2017 Consolidated Financial Statements.

Commodity Price Risk

The Company uses derivative commodity instruments from time to time to manage exposure to price volatility on a portion of its crude oil and natural gas production, and it also uses firm commitments for the purchase or sale of crude oil and natural gas. These contracts meet the definition of a derivative instrument and have been recorded at their fair value in accounts receivable, inventory, other assets, accounts payable and accrued liabilities and other long-term liabilities.

The Company's results will be impacted by a decrease in the price of crude oil and natural gas inventory. The Company has crude oil inventories that are feedstock, held at terminals or part of the in-process inventories at its refineries and at offshore sites. The Company also has natural gas inventory that could have an impact on earnings based on changes in natural gas prices. All these inventories are subject to a lower of cost or net realizable value test at each reporting period.

Foreign Currency Risk

The Company's results are affected by the exchange rates between various currencies including the Canadian and U.S. dollars. The majority of the Company's expenditures are in Canadian dollars while most of the Company's revenues are received in U.S. dollars from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. In addition, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in the Company's U.S. dollar-denominated debt and related interest expense, as expressed in Canadian dollars. The fluctuations in exchange rates are beyond the Company's control and could have a material adverse effect on the Company's results of operations and financial condition.

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollar denominated revenue to hedge against these potential fluctuations. The Company also designates its U.S denominated debt as a hedge of the Company's net investment in selected foreign operations with a U.S. dollar functional currency.

Interest Rate Risk

Interest rate risk is the impact of fluctuating interest rates on financial condition. In order to manage interest rate risk and the resulting interest expense, the Company mitigates some of its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt through the use of its credit facilities and various financial instruments. The optimal mix maintained will depend on market conditions. The Company may also enter into interest rate swaps from time to time as an additional means of managing current and future interest rate risk.

Counterparty Credit Risk

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties in a transaction fail to meet or discharge their obligation to the Company. The Company actively manages this exposure to credit and contract execution risk from both a customer and a supplier perspective. Internal credit policies govern the Company's credit portfolio and limit transactions according to a counterparty's and a supplier's credit quality. Counterparties for financial derivatives transacted by the Company are generally major financial institutions or counterparties with investment grade credit ratings.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. The Company's process for managing liquidity risk includes ensuring, to the extent possible, that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facilities and capacity to raise capital from various debt and equity capital markets under its shelf prospectuses. The availability of capital under its shelf prospectuses is dependent on market conditions at the time of sale.

Credit Rating Risk

Credit ratings affect the Company's ability to obtain both short-term and long-term financing and the cost of such financing. Additionally, the ability of the Company to engage in ordinary course derivative or hedging transactions and maintain ordinary course contracts with customers and suppliers on acceptable terms depends on the Company's credit ratings. A reduction in the current rating on the Company's debt by one or more of its rating agencies, particularly a downgrade below investment grade ratings, or a negative change in the Company's ratings outlook could adversely affect the Company's cost of financing and its access to sources of liquidity and capital. Credit ratings are intended to provide investors with an independent measure of credit quality of any issuer of securities. The credit ratings accorded to the Company's securities by the rating agencies are not recommendations to purchase, hold or sell the securities in as much as such ratings do not comment as to market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

The Company is committed to retaining investment grade credit ratings to support access to capital markets and currently has the following credit ratings:

	Standard and Poor's Rating Services	Moody's Investor Service ("Moody's")	Dominion Bond Rating Services Limited
Outlook/Trend	Stable	Stable	Stable
Senior Unsecured Debt	BBB+	Baa2	A(low)
Series 1 Preferred Shares	P-2(low)		Pfd-2(low)
Series 2 Preferred Shares	P-2(low)		Pfd-2(low)
Series 3 Preferred Shares	P-2(low)		Pfd-2(low)
Series 5 Preferred Shares	P-2(low)		Pfd-2(low)
Series 7 Preferred Shares	P-2(low)		Pfd-2(low)
Commercial Paper			R-1(low)

Debt Covenants

The Company's credit facilities include financial covenants, which contain a debt to capital covenant. If the Company does not comply with the covenants under these credit facilities, there is a risk that repayment could be accelerated.

6.0 Liquidity and Capital Resources

6.1 Summary of Cash Flow

Cash Flow Summary *($ millions)*	**2017**	2016
Cash flow		
Operating activities	**3,704**	1,971
Financing activities	**363**	(1,362)
Investing activities	**(2,789)**	632

Cash Flow from Operating Activities

Cash flow generated from operating activities increased by $1,733 million in 2017 compared to 2016. The increase was primarily due to higher realized global commodity prices combined with increased production from the Company's thermal bitumen developments and Asia Pacific operations, and a higher Chicago 3:2:1 crack spread and sales volumes in the U.S. Refining and Marketing operations.

Cash Flow from (used for) Financing Activities

Cash flow generated from financing activities increased by $1,725 million in 2017 compared to 2016. The increase was primarily due to the net issuance of $385 million in long-term debt in 2017, compared to the net repayment of $520 million of short-term debt and $768 million of long-term debt in 2016.

Cash Flow from (used for) Investing Activities

Cash flow used for investing activities increased by $3,421 million in 2017 compared to 2016. The increase was primarily due to increased capital expenditures and corporate acquisitions in 2017, compared to cash proceeds from asset sales of $2,935 million in 2016.

6.2 Working Capital Components

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2017, the Company's working capital was $2,109 million compared to $1,125 million at December 31, 2016. A reconciliation of the Company's working capital is as follows:

Working Capital *($ millions)*	**December 31, 2017**	December 31, 2016	Change
Cash and cash equivalents	**2,513**	1,319	1,194
Accounts receivable	**1,186**	1,036	150
Income taxes receivable	**164**	186	(22)
Inventories	**1,513**	1,558	(45)
Prepaid expenses	**145**	135	10
Restricted cash	**95**	84	11
Accounts payable and accrued liabilities	**(3,033)**	(2,226)	(807)
Short-term debt	**(200)**	(200)	—
Long-term debt due within one year	**—**	(403)	403
Contribution payable	**—**	(146)	146
Asset retirement obligations	**(274)**	(218)	(56)
Net working capital	**2,109**	1,125	984

The increase in cash and cash equivalents was primarily due to stronger operational performance resulting from the higher global commodity prices in 2017. Fluctuations in accounts receivable and accounts payable were due to the timing of settlements in 2017 compared to 2016. The decrease in income taxes receivable was due to the timing of expected tax refunds. The decrease in long-term debt due within one year was due to the timing of debt maturities. The decrease in contribution payable was due to the contribution being fully repaid in 2017.

6.3 Sources of Liquidity

Liquidity describes a company's ability to access cash. Sources of liquidity include funds from operations, proceeds from the issuance of equity, proceeds from the issuance of short and long-term debt, availability of short and long-term credit facilities and proceeds from asset sales. Since the Company operates in the Upstream oil and gas industry, it requires significant cash to fund capital programs necessary to maintain or increase production, develop reserves, acquire strategic oil and gas assets and repay maturing debt.

During times of low oil and gas prices, a portion of capital programs can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining the Company's production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, the Company frequently evaluates the options available with respect to sources of short and long-term capital resources. The Company believes that it has sufficient liquidity to sustain its operations, fund capital programs and meet non-cancellable contractual obligations and commitments in the short and long-term principally by cash generated from operating activities, cash on hand, the issuance of equity, the issuance of debt, borrowings under committed and uncommitted credit facilities and cash proceeds from asset sales. The Company is continually examining its options with respect to sources of long and short-term capital resources to ensure it retains financial flexibility.

At December 31, 2017, the Company had the following available credit facilities:

Credit Facilities *($ millions)*	Available	Unused
Operating facilities[(1)]	**850**	**428**
Syndicated credit facilities[(2)]	**4,000**	**3,800**
	4,850	**4,228**

(1) Consists of demand credit facilities and letter of credit.
(2) Commercial paper outstanding is supported by the Company's syndicated credit facilities.

At December 31, 2017, the Company had $4,228 million of unused credit facilities of which $3,800 million are long-term committed credit facilities and $428 million are short-term uncommitted credit facilities. A total of $422 million of the Company's short-term uncommitted borrowing credit facilities was used in support of outstanding letters of credit and $200 million of the Company's long-term committed borrowing credit facilities was used in support of commercial paper. At December 31, 2017, the Company had no direct borrowing against committed credit facilities. The Company's ability to renew existing bank credit facilities and raise new debt is dependent upon maintaining an investment grade debt rating and the condition of capital and credit markets. Credit ratings may be affected by the Company's level of debt, from time to time.

The Company's share capital is not subject to external restrictions. The Company's leverage covenant under both of its revolving syndicated credit facilities is debt to capital and calculated as total debt (long-term debt including long-term debt due within one year and short-term debt) and certain adjusting items specified in the agreement divided by total debt, shareholders' equity and certain adjusting items specified in the agreement. This covenant is used to assess the Company's financial strength. If the Company does not comply with the covenants under the syndicated credit facilities, there is the risk that repayment could be accelerated. The Company was in compliance with the syndicated credit facility covenants at December 31, 2017, and assessed the risk of non-compliance to be low.

The Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million available for general purposes. The Company's proportionate share is $5 million. There were no amounts drawn on this demand credit facility at December 31, 2017.

On December 22, 2015, the Company filed a universal short form base shelf prospectus (the "2015 U.S. Shelf Prospectus") with the Alberta Securities Commission and a related U.S. registration statement containing the 2015 U.S. Shelf Prospectus with the SEC that enabled the Company to offer up to US$3.0 billion of debt securities, common shares, preferred shares, subscription receipts, warrants and units of the Company in the United States up to and including January 22, 2018. During the 25-month period that the 2015 U.S. Shelf Prospectus and the related U.S registration statement were effective, securities could be offered in amounts, at prices and on terms set forth in a prospectus supplement.

In March 2016, holders of 1,564,068 Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Preferred Shares") exercised their option to convert their shares, on a one-for-one basis, to Cumulative Redeemable Preferred Shares, Series 2 (the "Series 2 Preferred Shares") and receive a floating rate quarterly dividend. The dividend rate applicable to the Series 2 Preferred Shares for the three month period commencing September 30, 2017, to, but excluding December 31, 2017, is equal to the sum of the Government of Canada 90 day treasury bill rate on August 31, 2017, plus 1.73 percent, being 2.472 percent. The floating rate quarterly dividend applicable to the Series 2 Preferred Shares will be reset every quarter. The dividend rate applicable to the Series 1 Preferred Shares for the five year period commencing March 31, 2016, to, but excluding March 31, 2021, is equal to the sum of the Government of Canada five year bond yield on March 1, 2016, plus 1.73 percent, being 2.404 percent. Both rates were calculated in accordance with the articles of amendment of the Company creating the Series 1 Preferred Shares and Series 2 Preferred Shares dated March 11, 2011.

On March 9, 2016, the maturity date for one of the Company's $2.0 billion revolving syndicated credit facilities, previously set to expire on December 14, 2016, was extended to March 9, 2020. In addition, the Company's leverage covenant under both of its revolving syndicated credit facilities ($2.0 billion maturing June 19, 2018, and $2.0 billion maturing March 9, 2020) was modified to a debt to capital covenant. At December 31, 2017, the Company was in compliance with the syndicated credit facility covenants and assesses the risk of non-compliance to be low.

On November 15, 2016, the Company repaid the maturing 7.55 percent notes issued under a trust indenture dated October 31, 1996. The amount paid to noteholders was $280 million, including $10 million of interest.

On March 10, 2017, the Company issued $750 million of 3.60 percent notes due March 10, 2027. The notes are redeemable at the option of the Company at any time, subject to a make-whole premium unless the notes are redeemed in the three month period prior to maturity. Interest is payable semi-annually on March 10 and September 10 of each year, beginning September 10, 2017. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness.

On March 30, 2017, the Company filed a universal short form base shelf prospectus (the "2017 Canadian Shelf Prospectus") with applicable securities regulators in each of the provinces of Canada that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and other units in Canada up to and including April 30, 2019.

On September 15, 2017, the Company repaid the maturing 6.20 percent notes issued under a trust indenture dated September 11, 2007. The amount paid to note holders was $365 million, including $11 million of interest.

At December 31, 2017, the Company had unused capacity of $3.0 billion under the 2017 Canadian Shelf Prospectus and US$3.0 billion in unused capacity under the 2015 U.S. Shelf Prospectus and related U.S. registration statement.

On January 29, 2018, the Company filed a universal short form base shelf prospectus (the "2018 U.S. Shelf Prospectus") with the Alberta Securities Commission. On January 30, 2018, the Company's related U.S. registration statement with the SEC containing the 2018 U.S. Shelf Prospectus became effective which enables the Company to offer up to US$3.0 billion of debt securities, common shares, preferred shares, subscription receipts, warrants and units of the Company in the U.S. up to and including February 29, 2020. During the 25-month period that the 2018 U.S. Shelf Prospectus and the related U.S registration statement are effective, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement. The 2018 U.S. Shelf Prospectus replaced the 2015 U.S. Shelf Prospectus. The ability of the Company to utilize the capacity under the 2017 Canadian Shelf Prospectus and the 2018 U.S. Shelf Prospectus and related U.S. registration statement is subject to market conditions at the time of sale.

Net Debt

Net debt, a non-GAAP measure (see Section 9.3), is calculated as total debt less cash and cash equivalents. The Company had total debt of $5,440 million and cash and cash equivalents of $2,513 million at December 31, 2017 compared to total debt of $5,339 million and cash and cash equivalents of $1,319 million at December 31, 2016. The Company's net debt at December 31, 2017 decreased by $1,093 million when compared to December 31, 2016:

Net Debt[1] *($ millions)*	**December 31, 2017**	December 31, 2016
Net debt at beginning of period	**(4,020)**	(6,686)
Change in net debt due to:		
Funds from operations[1]	**3,306**	2,198
Capital expenditures	**(2,220)**	(1,705)
Corporate acquisitions	**(670)**	—
Cash dividends paid on preferred shares	**(34)**	(27)
Change in non-cash working capital	**570**	(568)
Proceeds from asset sales	**192**	2,935
Effect of exchange rates on cash and cash equivalents	**(84)**	8
Effect of exchange rates on long-term debt	**284**	130
Contribution payable	**(142)**	(193)
Contribution to joint ventures	**(81)**	(102)
Other	**(28)**	(10)
	1,093	2,666
Net debt at end of period	**(2,927)**	(4,020)

(1) *Net debt and funds from operations are non-GAAP measures. Refer to Section 9.3 for a reconciliation to the GAAP measure.*

During the years ended December 31, 2017 and 2016, the Company's capital expenditures were funded by funds from operations. The Company's funds from operations are dependent on a number of factors, including commodity prices, production and sales volumes, refining and marketing margins, operating expenses, taxes, royalties and foreign exchange rates. Management prepares capital expenditure budgets annually which are regularly monitored and updated to adapt to changes in market factors. In addition, the Company requires authorizations for capital expenditures on projects, which assists with the management of capital.

The common share dividend was suspended by the Board of Directors in respect of the fourth quarter of 2015 with the persistent downward pressure on oil prices and the extended "lower for longer" outlook to provide the Company with further financial flexibility to achieve its business and financial objectives. The Board of Directors carefully considers numerous factors including earnings, commodity price outlook, future capital requirements, and the financial condition of the Company when it reviews the Common

Share dividend policy. On February 28, 2018, the Board of Directors declared a quarterly dividend of $0.075 per common share for the three-month period ended December 31, 2017. The dividend will be payable on April 2, 2018 to shareholders of record at the close of business on March 20, 2018.

6.4 Capital Structure

Capital Structure *($ millions)*	**December 31, 2017 Outstanding**
Total debt[(1)]	**5,440**
Shareholders' equity	**17,967**

[(1)] *Total debt is defined as long-term debt including long-term debt due within one year and short-term debt.*

The Company's objectives when managing capital are to maintain a flexible capital structure, which optimizes the cost of capital at acceptable risk, and to maintain investor, creditor and market confidence to sustain the future development of the business. The Company manages its capital structure and makes adjustments as economic conditions and the risk characteristics of its underlying assets change. The Company considers its capital structure to include shareholders' equity and debt, which was $23.4 billion at December 31, 2017 (December 31, 2016 – $23.0 billion). To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt and/or adjust its capital spending to manage its current and projected debt levels.

The Company monitors its capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of debt to capital employed and debt to funds from operations (refer to section 9.3). The Company's objective is to maintain a debt to capital employed target of less than 25 percent and a debt to funds from operations ratio of less than 2.0 times. At December 31, 2017, debt to capital employed was 23.2 percent (December 31, 2016 – 23.2 percent) and debt to funds from operations was 1.6 times (December 31, 2016 – 2.4 times), within the Company's targets.

The decrease in debt to funds from operations ratio as at December 31, 2017 was attributed to higher funds from operations due in large part to higher global commodity prices. To facilitate the management of these ratios, the Company prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The annual budget is approved by the Board of Directors.

6.5 Contractual Obligations, Commitments and Off-Balance Sheet Arrangements

Contractual Obligations and Other Commercial Commitments

In the normal course of business, the Company is obligated to make future payments. The following summarizes known non-cancellable contracts and other commercial commitments:

Contractual Obligations

Payments due by period ($ millions)	**2018**	**2019-2020**	**2021-2022**	**Thereafter**	**Total**
Long-term debt and interest on fixed rate debt	260	2,122	911	3,661	6,954
Operating leases[(1)]	164	230	247	1,540	2,181
Firm transportation agreements[(1)]	451	929	945	4,306	6,631
Unconditional purchase obligations[(2)]	1,965	3,103	2,155	6,675	13,898
Lease rentals and exploration work agreements	94	139	136	973	1,342
Obligations to fund equity investee[(3)]	51	132	140	451	774
Finance lease obligations[(4)]	69	138	120	993	1,320
Asset retirement obligations[(5)]	274	330	304	8,763	9,671
	3,328	7,123	4,958	27,362	42,771

[(1)] *Included in the total of operating leases and firm transportation agreements are blending and storage agreements and transportation commitments of $0.9 billion and $2.0 billion respectively with HMLP.*

[(2)] *Includes processing services, distribution services, insurance premiums, drilling services, natural gas purchases and the purchase of refined petroleum products, which includes agreements entered into during the year totaling an incremental $385 million per year for a term of 15 years related to the expanded Canadian truck transportation network.*

[(3)] *Equity investee refers to the Company's investment in Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for consolidated financial statement purposes*

[(4)] *Refer to Note 17 in the 2017 Consolidated Financial Statements.*

[(5)] *Asset retirement obligation amounts represent the undiscounted future payments for the estimated cost of abandonment, removal and remediation associated with retiring the Company's assets. The amounts are inclusive of $192 million of cash deposited into restricted accounts for funding of future asset retirement obligations in Asia Pacific.*

The Company updated its estimates for asset retirement obligations ("ARO") as outlined in Note 16 to the 2017 Consolidated Financial Statements. On an undiscounted and inflated basis, the ARO decreased from $11.4 billion as at December 31, 2016 to $9.7 billion as at December 31, 2017, primarily due to dispositions in Western Canada.

Other Obligations

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that decisions in any pending or threatened proceedings related to these and other matters, or any amount which it may be required to pay, would have a material adverse impact on its financial position, results of operations or liquidity.

The Company has income tax filings that are subject to audit and potential reassessment. The findings may impact the tax liability of the Company. The final results are not reasonably determinable at this time. Management believes that it has adequately provided for current and deferred income taxes.

During 2017, the Company completed a series of transactions related to the Canadian defined benefit pension plan, which was closed to new entrants in 1991. The Company recognized an $8 million loss on settlement related to the inactive plan members and a $3 million (net of tax of $1 million) loss in other comprehensive ("OCI") income for an annuity that was purchased to offset the defined benefit obligation for the active plan members. The Company also maintains a small defined benefit pension plan for the employees of the Superior Refinery which is closed to new entrants. Refer to Note 22 in the 2017 Consolidated Financial Statements.

In accordance with the provisions of the regulations of the People's Republic of China, the Company is required to deposit funds in separate accounts restricted to future decommissioning and disposal obligations. The funds will be used for decommissioning and disposal expenses upon the expiry or termination of the contracts for Asia Pacific. As at December 31, 2017, the Company has deposited funds of $192 million into the restricted cash accounts, of which $95 million relates to the Wenchang field and has been classified as current. The Company's participation in the Wenchang field expired in November 2017, and the amount of the decommissioning and disposal expenses was finalized in January 2018.

The Company is also subject to various contingent obligations that become payable only if certain events or rulings occur. The inherent uncertainty surrounding the timing and financial impact of these events or rulings prevents any meaningful measurement, which is necessary to assess their impact on future liquidity. Such obligations include environmental contingencies, contingent consideration and potential settlements resulting from litigation.

The Company has a number of contingent environmental liabilities, which individually have been estimated to be immaterial. These contingent environmental liabilities are primarily related to the migration of contamination at fuel outlets and certain legacy sites where the Company had previously conducted operations. The contingent environmental liabilities involved have been considered in aggregate and based on reasonable estimates the Company does not believe they will result, in aggregate, in a material adverse effect on its financial position, results of operations or liquidity.

Off-Balance Sheet Arrangements

The Company does not believe it has any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future effect on the Company's financial condition, results of operations, liquidity or capital expenditures.

Standby Letters of Credit

On occasion, the Company issues letters of credit in connection with transactions in which the counterparty requires such security.

6.6 Transactions with Related Parties

The Company performs management services as the operator of the assets held by HMLP for which it earns a management fee. The Company is also the contractor for HMLP and constructs its assets on a cost recovery basis with certain restrictions. HMLP charges an access fee to the Company for the use of its pipeline systems in performing the Company's blending business, and the Company also pays for transportation and storage services. These transactions are related party transactions, as the Company has a 35 percent ownership interest in HMLP and the remaining ownership interests in HMLP belong to PAH and CKI, which are affiliates of one of the Company's principal shareholders. For the year ended December 31, 2017, the Company charged HMLP $412 million related to construction and management services. For the year ended December 31, 2017, the Company had purchases from HMLP of $203 million related to the use of the pipeline for the Company's blending activities, transportation and storage activities, received distributions of $25 million and paid capital contributions of $17 million. As at December 31, 2017, the Company had $67 million due from HMLP.

The Company sells natural gas to and purchases steam from the Meridian Limited Partnership ("Meridian"), owner of the Meridian cogeneration facility, for use at the facility, Upgrader and Lloydminster ethanol plant. In addition, the Company provides facilities services and personnel for the operations of the Meridian cogeneration facility, which are primarily measured and reimbursed at cost, which equates to fair value. These transactions are related party transactions, as Meridian is an affiliate of one of the Company's principal shareholders, and have been measured at fair value. For the year ended December 31, 2017, the amount of natural gas sales to Meridian totalled $45 million. For the year ended December 31, 2017, the amount of steam purchased by the Company from Meridian totalled $15 million. For the year ended December 31, 2017, the total cost recovery by the Company for facilities services was $11 million. At December 31, 2017, the Company had $1 million due from Meridian with respect to these transactions.

At December 31, 2017, $31 million of the May 11, 2009, 7.25 percent senior notes were held by a related party, Ace Dimension Limited, and are included in long-term debt in the Company's consolidated balance sheet. The related party transaction was measured at fair market value at the date of the transaction and has been carried out on the same terms as applied with unrelated parties.

6.7 Outstanding Share Data

Authorized:

- unlimited number of common shares
- unlimited number of preferred shares

Issued and outstanding: February 23, 2017

• common shares	1,005,120,012
• cumulative redeemable preferred shares, series 1	10,435,932
• cumulative redeemable preferred shares, series 2	1,564,068
• cumulative redeemable preferred shares, series 3	10,000,000
• cumulative redeemable preferred shares, series 5	8,000,000
• cumulative redeemable preferred shares, series 7	6,000,000
• stock options	22,158,469
• stock options exercisable	12,760,000

7.0 Critical Accounting Estimates and Key Judgments

The Company's consolidated financial statements have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB"). Significant accounting policies are disclosed in Note 3 to the 2017 Consolidated Financial Statements. Certain of the Company's accounting policies require subjective judgment and estimation about uncertain circumstances.

7.1 Accounting Estimates

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and on a prospective basis. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the consolidated financial statements. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained, and as the Company's operating environment changes. Specifically, amounts recorded for depletion, depreciation, amortization and impairment, asset retirement obligations, assets and liabilities measured at fair value, employee future benefits, income taxes and reserves and contingencies are based on estimates.

Depletion, Depreciation, Amortization and Impairment

Eligible costs associated with oil and gas activities are capitalized on a unit of measure basis. Depletion expense is subject to estimates including petroleum and natural gas reserves, future petroleum and natural gas prices, estimated future remediation costs, future interest rates as well as other fair value assumptions. The aggregate of capitalized costs, net of accumulated DD&A, less estimated salvage values, is charged to DD&A over the life of the proved developed reserves using the unit of production method, except in the case of assets whose useful life is shorter or longer than the lifetime of the proved developed reserves of that field, in which case the straight-line method or a unit-of-production method based on total proved plus probable reserves is applied.

Impairment and Reversals of Impairment of Non-Financial Assets

The carrying amounts of the Company's non-financial assets are reviewed at the end of each reporting period to determine whether there is any indication of impairment or reversal of impairment. Determining whether there are any indications of impairment, or reversal of impairment, requires significant judgment of external factors, such as an extended change in prices or margins for oil and gas commodities or products, a significant change in an asset's market value, a significant change and revision of estimated volumes, revision of future development costs, a change in the entity's market capitalization or significant changes in the technological, market, economic or legal environment that would have an adverse impact on the entity. If impairment, or reversal of impairments, is indicated the amount by which the carrying value is different from the estimated fair value of the long-lived asset is charged to net earnings.

The determination of the recoverable amount for impairment, or reversal of impairment, involves the use of numerous assumptions and estimates. Estimates of future cash flows used in the evaluation of assets are made using management's forecasts of commodity prices, operating costs and future capital expenditures, marketing supply and demand, forecasted crack spreads, growth rate, discount rate and, in the case of oil and gas properties, expected production volumes. Expected production volumes take into account assessments of field reservoir performance and include expectations about proved and probable volumes and where applicable economically recoverable resources associated with interests in certain Husky properties which are risk-weighted utilizing geological, production, recovery, market price and economic projections. Either the cash flow estimates or the discount rate is risk-adjusted to reflect local conditions as appropriate. Future revisions to these assumptions impact the recoverable amount.

Impairment losses recognized for other assets in prior years are assessed at the end of each reporting period for indications that the impairment has decreased or no longer exists. An impairment loss is reversed only to the extent that the carrying amount of the asset or cash generating units ("CGUs") does not exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, if no impairment loss had been recognized.

Asset Retirement Obligations

Estimating ARO requires that the Company estimates costs that are many years in the future. Restoration technologies and costs are constantly changing, as are regulatory, political, environment, safety and public relations considerations. Inherent in the calculation of ARO are numerous assumptions and estimates, including the ultimate settlement amounts, future third-party pricing, inflation factors, credit-adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. Future revisions to these assumptions may result in changes to the ARO.

Fair Value of Financial Instruments

The fair values of derivatives are determined using valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. These estimates are also subject to change with fluctuations in commodity prices, interest rates, foreign currency exchange rates and estimates of non-performance. The actual settlement of a derivative instrument could differ materially from the fair value recorded and could impact future results.

Employee Future Benefits

The determination of the cost of the defined benefit pension plan and the other post-retirement benefit plans reflects a number of estimates that affect expected future benefit payments. These estimates include, but are not limited to, attrition, mortality, the rate of return on pension plan assets, salary escalations for the defined benefit pension plan and expected health care cost trends for the post-retirement health and dental care plan. The fair value of the plan assets is used for the purposes of calculating the expected return on plan assets.

Income Taxes

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. Estimates that require significant judgments are also made with respect to the timing of temporary difference reversals, the realizability of tax assets and in circumstances where the transaction and calculations for which the ultimate tax determination are uncertain. All tax filings are subject to audit and potential reassessment, often after the passage of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Legal, Environmental Remediation and Other Contingent Matters

The Company is required to determine both whether a loss is probable based on judgment and interpretation of laws and regulations and whether the loss can be reasonably estimated. When a loss is determined it is charged to net earnings. The Company must continually monitor known and potential contingent matters and make appropriate provisions by charges to net earnings when warranted by circumstances.

7.2 Key Judgments

Management makes judgments regarding the application of IFRS for each accounting policy. Critical judgments that have the most significant effect on the amounts recognized in the consolidated financial statements include determination of technical feasibility and commercial viability, impairment assessments, the determination of CGUs, changes in reserve estimates, the determination of a joint arrangement, the designation of the Company's functional currency and the fair value of related party transactions.

Exploration and Evaluation Costs

Costs directly associated with an exploration well are initially capitalized as exploration and evaluation assets. Expenditures related to wells that do not find reserves or where no future activity is planned are expensed as exploration and evaluation expenses. Exploration and evaluation costs are excluded from costs subject to depletion until technical feasibility and commercial viability is assessed or production commences. At that time, costs are either transferred to property, plant and equipment or their value is impaired. Impairment is charged directly to net earnings. Drilling results, required operating costs and capital expenditure and estimated reserves are important judgments when making this determination and may change as new information becomes available.

Impairment of Financial Assets

A financial asset is assessed at the end of each reporting period to determine whether it is impaired based on objective evidence indicating that one or more events have had a negative effect on the estimated future cash flows of that asset. Objective evidence used by the Company to assess impairment of financial assets includes quoted market prices for similar financial assets and historical collection rates for loans and receivables. The calculations for the net present value of estimated future cash flows related to derivative financial assets requires the use of estimates and assumptions, including forecasts of commodity prices, marketing supply and demand, product margins and expected production volumes, and it is possible that the assumptions may change, which may require a material adjustment to the carrying value of financial assets.

Cash Generating Units

The Company's assets are grouped into respective CGUs, which is the smallest identifiable group of assets, liabilities and associated goodwill that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The determination of the Company's CGUs is subject to management's judgment.

Reserves

Oil and gas reserves are evaluated internally and audited by independent qualified reserve engineers. The estimation of reserves is an inherently complex process and involves the exercise of professional judgment. Estimates are based on projected future rates of production, estimated commodity prices, engineering data and the timing of future expenditures, all of which are subject to uncertainty. Changes in reserve estimates can have an impact on reported net earnings through revisions to depletion, depreciation and amortization expense, in addition to determining possible impairments and reversal of impairments of property, plant and equipment.

Net reserves represent the Company's undivided gross working interest in total reserves after deducting crown, freehold and overriding royalty interests. Assumptions reflect market and regulatory conditions, as applicable, as at the balance sheet date and could differ significantly from other points in time throughout the year or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Joint Arrangements

Joint arrangements represent activities where the Company has joint control established by a contractual agreement. Joint control requires unanimous consent for financial and operational decisions. A joint arrangement is either a joint operation, whereby the parties have rights to the assets and obligations for the liabilities, or a joint venture, whereby the parties have rights to the net assets.

Classification of a joint arrangement as either joint operation or joint venture requires judgment. Management's considerations include, but are not limited to, determining if the arrangement is structured through a separate vehicle and whether the legal form and contractual arrangements give the entity direct rights to the assets and obligations for the liabilities within the normal course of business. Other facts and circumstances are also assessed by management, including the entity's rights to the economic benefits of assets and its involvement and responsibility for settling liabilities associated with the arrangement.

Functional and Presentation Currency

Functional currency is the currency of the primary economic environment in which the Company and its subsidiaries operate and is normally the currency in which the entity primarily generates and expends cash. The designation of the Company's functional currency is a management judgment based on the composition of revenues and costs in the locations in which it operates.

Related Party Judgments and Estimates

The Company entered into transactions and agreements in the normal course of business with certain related parties, joint arrangements and associates. These transactions are on terms equivalent to those that prevail in arm's-length transactions. Proceeds for disposition of assets to related parties are recognized at fair value, based on discounted cash flow forecast from those assets. Independent opinions of the fair value may be obtained. Changes in the assumptions used to determine these fair values may result in a material difference in the proceeds and any gain or loss on disposition.

8.0 Recent Accounting Standards and Changes in Accounting Policies

Recent Accounting Standards

The Company has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective.

Leases

In January 2016, the IASB issued IFRS 16 Leases, which replaces the current IFRS guidance on leases. Under the current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the balance sheet while operating leases are recognized in the Consolidated Statements of Income when the expense is incurred. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. The recognition of the present value of minimum lease payments for certain contracts currently classified as operating leases will result in increases to assets, liabilities, depletion, depreciation and amortization, and finance expense, and a decrease to production, operating and transportation expense upon implementation. An optional exemption to not recognize certain short-term leases and leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged. The standard will be effective for annual periods beginning on or after January 1, 2019. Early adoption is permitted, provided IFRS 15 Revenue from Contracts with Customers, has been applied, or is applied at the same date as IFRS 16.

Implementation of IFRS 16 consists of four phases:

- Project awareness and engagement - This phase includes identifying and engaging the appropriate members of the finance and operations teams, as well as communicating the key requirements of IFRS 16 to stakeholders, and creating a project steering committee.
- Scoping - This phase focuses on identifying and categorizing the Company's contracts, performing a high-level impact assessment and determining the adoption approach and which optional recognition exemptions will be applied by the Company. This phase also includes identifying the systems impacted by the new accounting standard and evaluating potential system solutions.
- Detailed analysis and solution development - This phase includes assessing which agreements contain leases and determining the expected conversion differences for leases currently accounted for as operating leases under the existing standard. This phase also includes selection of the system solution.
- Implementation - This phase includes implementing the changes required for compliance with IFRS 16. The focus of this phase is the approval and implementation of any new accounting and tax policies, processes, systems and controls, as required, as well as the execution of customized training programs and preparation of disclosures under IFRS 16.

The Company is currently in the detailed analysis and solutions development phase of implementing IFRS 16. The impact on the Company's consolidated financial statements upon adoption of IFRS 16 is currently being assessed.

Revenue from Contracts with Customers

In September 2015, the IASB published an amendment to IFRS 15, deferring the effective date of the standard by one year to annual periods beginning on or after January 1, 2018. IFRS 15 replaces existing revenue recognition guidance with a single comprehensive accounting model. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive when control is transferred to the purchaser. Early adoption is permitted.

Implementation of IFRS 15 consists of four phases:

- Project awareness and engagement - This phase includes identifying and engaging the appropriate members of the finance and operations teams, as well as communicating the key requirements of IFRS 15 to stakeholders.
- Scoping - This phase focuses on identifying the Company's major revenue streams, determining how and when revenue is currently recognized and determination of whether any changes are expected upon adoption.
- Detailed analysis and solution development - Steps in this phase include addressing any potential differences in revenue recognition identified in the scoping phase, according to the priority assigned. This involves detailed analysis of the IFRS 15 revenue recognition criteria, review of contracts with customers to ensure revenue recognition practices are in accordance with IFRS 15 and evaluating potential changes to revenue processes and systems.
- Implementation - This phase includes implementing the changes required for compliance with IFRS 15. The focus of this phase is the approval and implementation of any new accounting and tax policies, processes, systems and controls, as required, as well as the execution of customized training programs and preparation of disclosures under IFRS 15.

The Company has completed the assessment of IFRS 15 and is currently in the implementation phase. The Company will retrospectively adopt the standard on January 1, 2018. The adoption of IFRS 15 does not require any material changes to the amounts recorded in the consolidated financial statements; however, it will require additional disclosures.

Financial Instruments

In July 2014, the IASB issued IFRS 9, "Financial Instruments" to replace IAS 39, which provides a single model for classification and measurement based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial instruments. For financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in OCI rather than net earnings, unless this creates an accounting mismatch. IFRS 9 includes a new, forward-looking 'expected loss' impairment model that will result in a more timely recognition of expected credit losses. In addition, IFRS 9 provides a substantially-reformed approach to hedge accounting. The standard is effective for annual periods beginning on or after January 1, 2018, with required retrospective application and early adoption permitted.

Implementation of IFRS 9 consists of four phases:

- Project awareness and engagement - This phase includes identifying and engaging the appropriate members of the finance and operations teams, as well as communicating the key requirements of IFRS 9 to stakeholders.
- Scoping - This phase focuses on identifying the Company's financial instruments, determining accounting treatment for in-scope financial instruments under IFRS 9, and determination of whether any changes are expected upon adoption.
- Detailed analysis and solution development - This phase includes addressing differences in accounting for financial instruments. Steps in this phase involve detailed analysis of the IFRS 9 recognition impacts, measurement and disclosure requirements, and evaluating potential changes to accounting processes.
- Implementation - This phase includes implementing the changes required for compliance with IFRS 9. The focus of this phase is the approval and implementation of any new accounting and tax policies, processes, systems and controls, as required, as well as the preparation of disclosures under IFRS 9.

The Company has completed the assessment of IFRS 9 and is currently in the implementation phase. The Company will retrospectively adopt the standard on January 1, 2018. The adoption of IFRS 9 does not require any material changes to the consolidated financial statements.

Amendments to the IFRS 2 Share-based Payment

In June 2016, the IASB issued amendments to IFRS 2 to be applied prospectively for annual periods beginning on or after January 1, 2018 with early adoption permitted. The amendments clarify how to account for certain types of share-based payment arrangements. The adoption of the amendments does not have a material impact on the Company's consolidated financial statements.

Change in Accounting Policy

The Company has applied the following amendments to accounting standards issued by the IASB for the first time for the annual reporting period commencing January 1, 2017:

Amendments to IAS 7 Statement of Cash Flows

The amendments require disclosure of information enabling users of financial statements to evaluate changes in liabilities arising from financing activities. The adoption of this amended standard resulted in the disclosure of a reconciliation to changes in liabilities from financing activities. Refer to Note 15 of the Consolidated Financial Statements.

Amendments to IAS 12

The amendments clarify the recognition of deferred tax assets for unrealized losses on debt instruments measured at fair value. The adoption of the amendments has no material impact on the Company's consolidated financial statements.

9.0 Reader Advisories

9.1 Forward-Looking Statements

Certain statements in this document are forward-looking statements and information (collectively, "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The forward-looking statements contained in this document are forward-looking and not historical facts.

Some of the forward-looking statements may be identified by statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result", "are expected to", "will continue", "is anticipated", "is targeting", "is estimated", "intend", "plan", "projection", "could", "aim", "vision", "goals", "objective", "target", "scheduled" and "outlook"). In particular, forward-looking statements in this document include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally: the Company's general strategic plans and growth strategies; the Company's 2018 production guidance, including guidance for specified areas and product types; the Company's objective of maintaining stated debt to funds from operations and debt to capital employed ratio targets; and the Company's 2018 Upstream capital expenditure program;

- with respect to the Company's thermal developments: anticipated timing of first production from and design capacity of the Company's Rush Lake 2 thermal development and its three Lloyd thermal projects at Dee Valley, Spruce Lake North and Spruce Lake Central; the timing of commencement of construction at Dee Valley; the timing of commencement of site clearing and construction at Spruce Lake Central and Spruce Lake North; the expected timing of first production from, and design capacity of, the two new thermal projects at Westhazel and Edam Central; the expected volume of long-life thermal production expected to be brought on by the Company in the next four years; the expected timing of ramp up of production and expected 2018 production volumes from the Tucker Thermal Project; and expected timing to reach nameplate capacity at the Sunrise Energy Project;

- with respect to the Company's Western Canada resource plays: the Company's strategic and drilling plans for its Western Canada portfolio; and expected timing that six wells in the Spirit River formation and two wells at Wembley will start production;

- with respect to the Company's Offshore business in Asia Pacific: the expected timing of commencement of construction at, and first production from, Liuhua 29-1; the Company's drilling plans at Block 15/33 and Block 16/25 offshore China; expected total gross daily sales volumes of natural gas and NGL once production is fully ramped up at the BD Project and the MDA-MBH and MDK fields; the expected timing of drilling of five MDA field production wells and two MBH field production wells, and the expected timing of first gas therefrom; and the expected timing of tie-in of the additional MDK shallow water field;

- with respect to the Company's Offshore business in the Atlantic: the expected timing of first oil and the expected timing and volume of gross peak production at the West White Rose Project; and the potential new development at Northwest White Rose;

- with respect to the Company's Infrastructure and Marketing business, the expected timing of completion of construction of HMLP's new 150-kilometre pipeline system; and

- with respect to the Company's Downstream operating segment: the expected timing of a final investment decision on the potential expansion of the Company's Lloydminster Asphalt Refinery; the expected timing of completion of the crude oil flexibility project at the Lima Refinery; and the expected timing of completion of a project to increase the heavy oil processing capacity at the Superior Refinery.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary from reserves and production estimates.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this document are reasonable, the Company's forward-looking statements have been based on assumptions and factors concerning future events, including the timing of regulatory approvals, that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources, including third party consultants, suppliers and regulators, among others.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. Some of these risks, uncertainties and other factors are similar to those faced by other oil and gas companies and some are unique to the Company.

The Company's Annual Information Form for the year ended December 31, 2017 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

New factors emerge from time to time and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon management's assessment of the future considering all information available to it at the relevant time. Any forward-looking statement speaks only as of the date on which such statement is made and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events.

9.2 Oil and Gas Reserves Reporting

Disclosure of Oil and Gas Reserves and Other Oil and Gas Information

Unless otherwise indicated: (i) reserves estimates have been prepared by internal qualified reserves evaluators in accordance with the Canadian Oil and Gas Evaluation Handbook, have an effective date of December 31, 2017 and represent the Company's working interest share; (ii) projected and historical production volumes provided represent the Company's working interest share before royalties; and (iii) historical production volumes provided are for the year ended December 31, 2017.

The Company uses the term barrels of oil equivalent ("boe"), which is consistent with other oil and gas companies' disclosures, and is calculated on an energy equivalence basis applicable at the burner tip whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. The term boe is used to express the sum of the total company products in one unit that can be used for comparisons. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is used for consistency with other oil and gas companies but does not represent value equivalency at the wellhead.

The Company uses the term reserves replacement ratio, which is consistent with other oil and gas companies' disclosures. Reserves replacement ratios for a given period are determined by taking the Company's incremental proved reserves additions for that period divided by the Company's Upstream gross production for the same period. The reserves replacement ratio measures the amount of reserves added to a company's reserves base during a given period relative to the amount of oil and gas produced during that same period. A company's reserves replacement ratio must be at least 100 percent for the company to maintain its reserves. The reserves replacement ratio only measures the amount of reserves added to a company's reserve base during a given period. Reserves replacement ratios that exclude economic factors will exclude the impacts that changing oil and gas prices have.

Note to U.S. Readers

The Company reports its reserves information in accordance with Canadian practices and specifically in accordance with National Instrument 51-101, "Standards of Disclosure for Oil and Gas Disclosure", adopted by the Canadian securities regulators. Because the Company is permitted to prepare its reserves information in accordance with Canadian disclosure requirements, it may use certain terms in that disclosure that U.S. oil and gas companies generally do not include or may be prohibited from including in their filings with the Securities and Exchange Commission (the "SEC") .

9.3 Non-GAAP Measures

Disclosure of non-GAAP Measures

The Company uses measures primarily based on IFRS and also uses some secondary non-GAAP measures. The non-GAAP measures included in this MD&A and related disclosures are: adjusted net earnings (loss), funds from operations, free cash flow, net debt, operating netback, debt to capital employed, debt to funds from operations and LIFO. None of these measures is used to enhance the Company's reported financial performance or position. There are no comparable measures in accordance with IFRS for operating netback, debt to capital employed or debt to funds from operations. These are useful complementary measures in assessing the Company's financial performance, efficiency and liquidity. The non-GAAP measures do not have standardized meanings prescribed by IFRS and therefore are unlikely to be comparable to similar measures presented by other issuers. They are common in the reports of other companies but may differ by definition and application. All non-GAAP measures are defined below.

Adjusted Net Earnings (Loss)

Adjusted net earnings (loss) is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "net earnings (loss)" as determined in accordance with IFRS, as an indicator of financial performance. Adjusted net earnings (loss) is comprised of net earnings (loss) and excludes items such as after-tax property, plant and equipment impairment charges (reversals), goodwill impairment charges, exploration and evaluation asset write-downs, inventory write-downs and loss (gain) on sale of assets which are not considered to be indicative of the Company's ongoing financial performance. Adjusted net earnings (loss) is a complementary measure used in assessing the Company's financial performance through providing comparability between periods. Adjusted net earnings (loss) was redefined in the second quarter of 2016. Previously, adjusted net earnings (loss) was defined as net earnings (loss) plus after-tax property, plant and equipment impairment charges (reversals), goodwill impairment charges, exploration and evaluation asset write-downs and inventory write-downs.

The following table shows the reconciliation of net earnings (loss) to adjusted net earnings (loss) for the three months and years ended December 31:

Adjusted Net Earnings	Three months ended Dec. 31,		Year ended Dec. 31,		
($ millions)	**2017**	2016	**2017**	2016	2015
Net earnings (loss)	**672**	186	**786**	922	(3,850)
Impairment (impairment reversal) of property, plant and equipment, net of tax	**3**	(202)	**126**	(190)	3,664
Impairment of goodwill	**—**	—	**—**	—	160
Exploration and evaluation asset write-downs, net of tax	**—**	41	**4**	63	177
Inventory write-downs, net of tax	**—**	6	**—**	6	14
Gain on sale of assets, net of tax	**(10)**	(37)	**(34)**	(1,456)	(16)
Adjusted net earnings (loss)	**665**	(6)	**882**	(655)	149

Debt to Capital Employed

Debt to capital employed is a non-GAAP measure and is equal to long-term debt, long-term debt due within one year, and short-term debt divided by capital employed. Capital employed is equal to long-term debt, long-term debt due within one year, short-term debt and shareholders' equity. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

Debt to Funds from Operations

Debt to funds from operations is a non-GAAP measure and is equal to long-term debt, long-term debt due within one year and short-term debt divided by funds from operations. Funds from operations is equal to cash flow – operating activities plus change in non-cash working capital. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

The following table shows the calculation of debt to funds from operations for the periods ended December 31, 2017, 2016 and 2015:

Debt to funds from operations *($ millions)*	**December 31, 2017**	December 31, 2016	December 31, 2015
Total debt	**5,440**	5,339	6,756
Funds from operations	**3,306**	2,198	3,333
Debt to funds from operations	**1.6**	2.4	2.0

Funds from Operations and Free Cash Flow

Funds from operations is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "cash flow – operating activities" as determined in accordance with IFRS, as an indicator of financial performance. Funds from operations is presented in the Company's financial reports to assist management and investors in analyzing operating performance of the Company in the stated period. Funds from operations equals cash flow – operating activities plus change in non-cash working capital.

Funds from operations has been restated in the second quarter of 2017 in order to be more comparable to similar non-GAAP measures presented by other companies. Changes from prior period presentation include the removal of adjustments for settlement of asset retirement obligations and deferred revenue. Prior periods have been restated to conform to current presentation.

Free cash flow is a non-GAAP measure, which should not be considered an alternative to, or more meaningful than, "cash flow – operating activities" as determined in accordance with IFRS, as an indicator of financial performance. Free cash flow is presented to assist management and investors in analyzing operating performance by the business in the stated period. Free cash flow equals funds from operations less capital expenditures.

The following table shows the reconciliation of cash flow – operating activities to funds from operations and free cash flow, and related per share amounts for the three months and years ended December 31:

Reconciliation of Cash Flow	Three months ended Dec. 31,		Year ended Dec. 31,		
($ millions)	**2017**	2016	**2017**	2016	2015
Net earnings (loss)	**672**	186	**786**	922	(3,850)
Items not affecting cash:					
Accretion	**28**	30	**112**	126	121
Depletion, depreciation, amortization and impairment	**647**	405	**2,882**	2,462	8,644
Inventory write-down to net realizable value	**—**	9	**—**	9	22
Exploration and evaluation expenses	**—**	56	**6**	86	242
Deferred income taxes (recoveries)	**(360)**	45	**(359)**	29	(1,827)
Foreign exchange (gain) loss	**1**	(29)	**(4)**	(4)	27
Stock-based compensation	**25**	3	**45**	33	(39)
Gain on sale of assets	**(13)**	(52)	**(46)**	(1,634)	(22)
Unrealized market to market loss (gain)	**57**	26	**56**	38	(14)
Share of equity investment loss (gain)	**(1)**	(38)	**(61)**	(15)	5
Other	**8**	29	**16**	24	20
Settlement of asset retirement obligations	**(45)**	(31)	**(136)**	(87)	(98)
Deferred revenue	**(5)**	23	**(16)**	209	102
Distribution from joint ventures	**25**	—	**25**	—	—
Change in non-cash working capital	**337**	(18)	**398**	(227)	427
Cash flow – operating activities	**1,376**	644	**3,704**	1,971	3,760
Change in non-cash working capital	**(337)**	18	**(398)**	227	(427)
Funds from operations	**1,039**	662	**3,306**	2,198	3,333
Capital expenditures	**(745)**	(391)	**(2,220)**	(1,705)	(3,005)
Free cash flow	**294**	271	**1,086**	493	328
Funds from operations – basic	**1.03**	0.66	**3.29**	2.19	3.39
Funds from operations – diluted	**1.03**	0.66	**3.29**	2.19	3.39

LIFO

The Chicago 3:2:1 market crack spread benchmark is based on LIFO inventory costing, a non-GAAP measure, which assumes that crude oil feedstock costs are based on the current month price of WTI, while on a FIFO basis, the comparable GAAP measure, crude oil feedstock costs included in realized margins reflect purchases made in previous months. Management believes that comparisons between LIFO and FIFO inventory costing assist management and investors in assessing differences in the Company's realized refining margins compared to the Chicago 3:2:1 market crack spread benchmark.

Net Debt

Net debt is a non-GAAP measure that equals total debt less cash and cash equivalents. Total debt is calculated as long-term debt, long-term debt due within one year and short-term debt. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

The following table shows the reconciliation of total debt to net debt as at December 31, 2017, 2016 and 2015:

Net Debt *($ millions)*	**December 31, 2017**	December 31, 2016	December 31, 2015
Short-term debt	**200**	200	720
Long-term debt due within one year	**—**	403	277
Long-term debt	**5,240**	4,736	5,759
Total debt	**5,440**	5,339	6,756
Cash and cash equivalents	**(2,513)**	(1,319)	(70)
Net debt	**2,927**	4,020	6,686

Operating Netback

Operating netback is a common non-GAAP metric used in the oil and gas industry. Management believes this measurement assists management and investors to evaluate the specific operating performance by product at the oil and gas lease level. Operating netback is calculated as gross revenue less royalties, production and operating and transportation costs on a per unit basis.

9.4 Additional Reader Advisories

Intention of Management's Discussion and Analysis

This Management's Discussion and Analysis is intended to provide an explanation of financial and operational performance compared with prior periods and the Company's prospects and plans. It provides additional information that is not contained in the Company's Consolidated Financial Statements.

Review by the Audit Committee

This Management's Discussion and Analysis was reviewed by the Company's Audit Committee and approved by the Board of Directors on February 28, 2018. Any events subsequent to that date could materially alter the veracity and usefulness of the information contained in this document.

Additional Husky Documents Filed with Securities Commissions

This Management's Discussion and Analysis dated February 28, 2018, should be read in conjunction with the 2017 Consolidated Financial Statements and related notes. Readers are also encouraged to refer to the Company's interim reports filed for 2017, which contain Management's Discussion and Analysis and Consolidated Financial Statements, and the Company's Annual Information Form for the year ended December 31, 2017, filed separately with Canadian regulatory agencies, and annual Form 40-F filed with the SEC, the U.S. federal securities regulatory agency. These documents are available at www.sedar.com, at www.sec.gov and www.huskyenergy.com. Husky's Management's Discussion and Analysis for the interim period ended December 31, 2017, is incorporated herein by reference.

Use of Pronouns and Other Terms

"Husky" and "the Company" refer to Husky Energy Inc. on a consolidated basis.

Standard Comparisons in this Document

Unless otherwise indicated, comparisons of results are for the years ended December 31, 2017 and 2016 and the Company's financial position at December 31, 2017 and 2016.

Reclassifications and Materiality for Disclosures

Certain prior year amounts have been reclassified to conform to current year presentation. Materiality for disclosures is determined on the basis of whether the information omitted or misstated would cause a reasonable investor to change his or her decision to buy, sell or hold Husky's securities.

Additional Reader Guidance

Unless otherwise indicated:

- Financial information is presented in accordance with IFRS as issued by the IASB.
- All dollar amounts are in Canadian dollars, unless otherwise indicated.
- Unless otherwise indicated, all production volumes quoted are gross, which represents the Company's working interest share before royalties.
- Prices are presented before the effect of hedging.

Terms

Adjusted Net Earnings (Loss)	*Net earnings (loss) before after-tax property, plant and equipment impairment charges (reversals), goodwill impairment charges, exploration and evaluation asset write-downs, inventory write-downs and loss (gain) on the sale of assets*
Asia Pacific	*Includes Upstream oil and gas exploration and production activities located offshore China and Indonesia*
Atlantic	*Includes Upstream oil and gas exploration and production activities located offshore Newfoundland and Labrador*
Bitumen	*Bitumen is a naturally occurring solid or semi-solid hydrocarbon consisting mainly of heavier hydrocarbons, with a viscosity greater than 10,000 millipascal-seconds or 10,000 centipoise measured at the hydrocarbon's original temperature in the reservoir and at atmospheric pressure on a gas-free basis, and that is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods*
Capital Employed	*Long-term debt, long-term debt due within one year, short-term debt and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses but does not include asset retirement obligations or capitalized interest*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Debt to Capital Employed	*Long-term debt, long-term debt due within one year and short-term debt divided by capital employed*
Debt to Funds from Operations	*Long-term debt, long-term debt due within one year and short-term debt divided by funds from operations*
Diluent	*A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil and bitumen to facilitate transmissibility of the oil through a pipeline*
Feedstock	*Raw materials which are processed into petroleum products*
Free Cash Flow	*Funds from operations less capital expenditures*
Funds from Operations	*Cash flow - operating activities plus change in non-cash working capital.*
Gross/Net Acres/Wells	*Gross refers to the total number of acres/wells in which a working interest is owned. Net refers to the sum of the fractional working interests owned by a company*
Gross Reserves/Production	*A company's working interest share of reserves/production before deduction of royalties*
Heavy crude oil	*Crude oil with a relative density greater than 10 degrees API gravity and less than or equal to 22.3 degrees API gravity*
high-TAN	*A measure of acidity. Crude oils with a high content of naphthenic acids are referred to as high total acid number (TAN) crude oils or high acid crude oil. The TAN value is defined as the milligrams of Potassium Hydroxide required to neutralize the acidic group of one gram of the oil sample. Crude oils in the industry with a TAN value greater than 1 are referred to as high-TAN crudes*
Last in first out ("LIFO")	*Last in first out accounting assumes that crude oil feedstock costs are based on the current month price of WTI*
Light crude oil	*Crude oil with a relative density greater than 31.1 degrees API gravity*
Medium crude oil	*Crude oil with a relative density that is greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity*
Net Debt	*Total debt less cash and cash equivalents*
Net Revenue	*Gross revenues less royalties*
NOVA Inventory Transfer ("NIT")	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
Oil sands	*Sands and other rock materials that contain crude bitumen and include all other mineral substances in association therewith*
Operating Netback	*Gross revenue less royalties, operating costs and transportation costs on a per unit basis*
Plan of Development	*As it relates to the Company's operations in Indonesia, a Plan of Development represents development planning on one or more oil and gas fields in an integrated and optimal plan for the production of hydrocarbon reserves considering technical, economical and environmental aspects. An initial Plan of Development in a development area needs both SKK Migas and the Minister of Energy and Mineral Resources approvals. Subsequent Plans of Development in the same development area only need SKK Migas approval.*
Probable reserves	*Those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves*
Proved developed reserves	*Those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing*
Proved reserves	*Reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.*
Proved undeveloped reserves	*Those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable, possible) to which they are assigned*

Seismic survey	*A method by which the physical attributes in the outer rock shell of the earth are determined by measuring, with a seismograph, the rate of transmission of shock waves through the various rock formations*
Shareholders' Equity	*Common shares, preferred shares, contributed surplus, retained earnings, accumulated other comprehensive income and non-controlling interest*
Stratigraphic Well	*A geologically directed test well to obtain information. These wells are usually drilled without the intention of being completed for production*
Synthetic Oil	*A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content*
Thermal	*Use of steam injection into the reservoir in order to enable heavy oil and bitumen to flow to the well bore.*
Total Debt	*Long-term debt including long-term debt due within one year and short-term debt*
Turnaround	*Performance of scheduled plant or facility maintenance requiring the complete or partial shutdown of the plant or facility operations*
Western Canada	*Includes Upstream oil and gas exploration and development activities located in Alberta, Saskatchewan and British Columbia*

Units of Measure

bbls	*barrels*	*mboe*	*thousand barrels of oil equivalent*
bbls/day	*barrels per day*	*mboe/day*	*thousand barrels of oil equivalent per day*
bcf	*billion cubic feet*	*mcf*	*thousand cubic feet*
boe	*barrels of oil equivalent*	*mcfge*	*million cubic feet of gas equivalent*
boe/day	*barrels of oil equivalent per day*	*mmbbls*	*million barrels*
GJ	*gigajoule*	*mmboe*	*million barrels of oil equivalent*
mbbls	*thousand barrels*	*mmbtu*	*million British Thermal Units*
mbbls/day	*thousand barrels per day*	*mmcf*	*million cubic feet*
mbbls	*thousand barrels*	*mmcf/day*	*million cubic feet per day*
mbbls/day	*thousand barrels per day*	*m3*	*cubic meter*

9.5 Disclosure Controls and Procedures

Disclosure Controls and Procedures

Husky's management, under supervision of the Chief Executive Officer and the Chief Financial Officer, have evaluated the effectiveness of Husky's disclosure controls and procedures (as defined in the rules of the SEC and the Canadian Securities Administrators ("CSA")) as at December 31, 2017, and have concluded that such disclosure controls and procedures are effective.

Management's Annual Report on Internal Control over Financial Reporting

The following report is provided by management in respect of Husky's internal controls over financial reporting (as defined in the rules of the SEC and the CSA):

1) Husky's management, under the supervision of the Chief Executive Officer and Chief Financial Officer, is responsible for designing, establishing and maintaining adequate internal control over financial reporting for Husky. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

2) Husky's management has used the Committee of Sponsoring Organizations of the Treadway Commission framework to evaluate the effectiveness of Husky's internal control over financial reporting.

3) As at December 31, 2017, management, under the supervision of the Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of Husky's internal control over financial reporting and concluded that such internal control over financial reporting is effective.

4) KPMG LLP, who has audited the Consolidated Financial Statements of Husky for the year ended December 31, 2017, has also issued a report on internal controls over financial reporting under Auditing Standard No. 5 of the Public Company Accounting Oversight Board (United States) that attests to Husky's internal controls over financial reporting.

Changes in Internal Control over Financial Reporting

There have been no changes in Husky's internal control over financial reporting during the year ended December 31, 2017, that have materially affected or are reasonably likely to materially affect its internal control over financial reporting.

10.0 Selected Quarterly Financial and Operating Information

10.1 Summary of Quarterly Results

Fourth Quarter Results Summary *($ millions, except where indicated)*	Three months ended **Dec. 31** **2017**	 Dec. 31 2016
Gross revenues and marketing and other		
Upstream		
Exploration and Production	**1,355**	1,215
Infrastructure and Marketing	**633**	186
Downstream		
Upgrading	**452**	340
Canadian Refined Products	**815**	603
U.S. Refining and Marketing	**2,755**	1,890
Corporate and Eliminations	**(476)**	(369)
Total gross revenues and marketing and other	**5,534**	3,865
Net earnings (loss)		
Upstream		
Exploration and Production	**170**	198
Infrastructure and Marketing	**(27)**	18
Downstream		
Upgrading	**48**	32
Canadian Refined Products	**39**	8
U.S. Refining and Marketing	**129**	19
Corporate and Eliminations	**313**	(89)
Net earnings	**672**	186
Per share – Basic	**0.66**	0.19
Per share – Diluted	**0.66**	0.19
Adjusted net earnings (loss)(1)	**665**	(6)
Cash flow – operating activities	**1,376**	644
Funds from operations(1)	**1,039**	662
Per share – Basic	**1.03**	0.66
Per share – Diluted	**1.03**	0.66
Upstream		
Daily gross production		
Crude oil and NGL production *(mbbls/day)*(3)	**231.2**	234.5
Natural gas production *(mmcf/day)*(3)	**534.9**	555.4
Total production *(mboe/day)*	**320.4**	327.0
Average sales prices realized *($/boe)*		
Crude oil and NGL *($/bbl)*(3)	**51.06**	42.27
Natural gas *($/mcf)*(3)	**5.89**	5.65
Total average sales prices realized *($/boe)*	**46.69**	39.90
Downstream		
Refinery throughput		
Lloydminster Upgrader *(mbbls/day)*	**78.2**	66.5
Lloydminster Refinery *(mbbls/day)*	**30.1**	28.4
Prince George Refinery *(mbbls/day)*	**11.3**	11.8
Lima Refinery *(mbbls/day)*	**164.5**	165.1
BP-Husky Toledo Refinery *(mbbls/day)*	**81.0**	78.8
Superior Refinery *(mbbls/day)*(2)	**22.0**	—
Total throughput *(mbbls/day)*	**387.1**	350.6

Fourth Quarter Results Summary (continued)	Three months ended	
($ millions, except where indicated)	**Dec. 31 2017**	Dec. 31 2016
Upgrading unit margin *($/bbl)*	**20.65**	18.85
Upgrading synthetic crude oil sales *(mbbls/day)*	**56.5**	50.0
Upgrading total sales *(mbbls/day)*	**77.9**	66.9
Retail fuel sales *(million of litres/day)*	**8.0**	6.6
Canadian light oil margins *($/litre)*	**0.052**	0.057
Lloydminster Refinery asphalt margin *($/bbl)*	**15.79**	20.80
U.S. Refining Margin *(US$/bbl crude throughput)*	**14.71**	9.86
U.S./Canadian dollar exchange rate *(US$)*	**0.786**	0.750

(1) Adjusted net earnings (loss) and funds from operations are non-GAAP measures. Refer to Section 9.3 for a reconciliation to the GAAP measures.
(2) The Superior Refinery was acquired on November 8, 2017.
(3) Reported production volumes and associated per unit values include Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for financial statement purposes.

Gross Revenue and Marketing and Other

The Company's consolidated gross revenues and marketing and other increased by $1,669 million in the fourth quarter of 2017 compared to the fourth quarter of 2016.

In the Upstream business segment, Exploration and Production gross revenues increased primarily due to higher commodity pricing in the fourth quarter of 2017, which was partially offset by a higher Canadian dollar. Infrastructure and Marketing gross revenues and marketing and other increased primarily due to increased volumes and prices.

In the Downstream business segment, Upgrading gross revenues increased primarily due to higher realized prices for synthetic crude oil and higher sales volumes in 2017, as the Upgrader was in plant maintenance in the fourth quarter of 2016. Canadian Refined Products gross revenues increased primarily due to higher fuel sales volumes. U.S. Refining and Marketing gross revenues increased primarily due to higher sales volumes and higher realized product pricing in the fourth quarter of 2017 compared to the same period in 2016.

Net Earnings

The Company's consolidated net earnings increased by $486 million in the fourth quarter of 2017 compared to the same period in 2016.

In the Upstream business segment, Exploration and Production net earnings decreased primarily due to the 2016 net after-tax impairment reversal of $202 million on assets located in Western Canada. The decrease was partially offset by higher commodity pricing in the fourth quarter of 2017, compared to the fourth quarter of 2016.

In the Downstream business segment, Upgrading and Canadian Refined Products net earnings increased primarily due to the same factors which impacted gross revenues and marketing and other. U.S. Refining and Marketing net earnings increased primarily due to the higher Chicago 3:2:1 crack spread in the fourth quarter of 2017 compared to the same period in 2016. The Company recorded FIFO gains of $45 million during the fourth quarter of 2017 compared to FIFO gains of $25 million during the fourth quarter of 2016.

In the fourth quarter of 2017, the Company recognized $436 million in deferred tax recovery related to the reduction in the U.S. Federal corporate tax rate that will take effect in 2018.

Adjusted Net Earnings (Loss)

Adjusted net earnings (loss), which excludes after-tax property, plant and equipment impairment (reversal), goodwill impairment charges, exploration and evaluation asset write-downs, inventory write-downs and losses (gains) on sale of assets, increased by $671 million in the fourth quarter of 2017 compared to the fourth quarter of 2016. The increase was primarily attributable to the same factors which impacted net earnings.

Cash flow – operating activities and Funds from Operations

Cash flow – operating activities and funds from operations increased by $732 million and $377 million, respectively, in the fourth quarter of 2017 compared to the fourth quarter of 2016 primarily due to the same factors which impacted adjusted net earnings (loss). Funds from operations is a non-GAAP measure; refer to section 9.3.

Daily Gross Production

Production decreased by 6.6 mbbls/day during the fourth quarter of 2017 compared to the fourth quarter of 2016 as a result of:

- Decreased production from Western Canada primarily due to the disposition of select legacy assets in 2016 and 2017.

Partially offset by:

- Increased production from thermal bitumen developments;
- Increased natural gas and NGL production from the Liwan Gas Project; and
- Increased natural gas production due to new production from the BD Project.

Segmented Operational Information

Segmented Operational Information *($ millions, except where indicated)*	2017 Q4	2017 Q3	2017 Q2	2017 Q1	2016 Q4	2016 Q3	2016 Q2	2016 Q1
Gross revenues and marketing and other								
Upstream								
Exploration and Production	**1,355**	**1,157**	**1,215**	**1,251**	1,215	941	1,044	836
Infrastructure and Marketing	**633**	**509**	**425**	**369**	186	280	288	113
Downstream								
Upgrading	**452**	**377**	**227**	**384**	340	334	369	281
Canadian Refined Products	**815**	**802**	**602**	**568**	603	678	585	435
U.S. Refining and Marketing[1]	**2,755**	**2,292**	**2,135**	**2,173**	1,890	1,642	1,337	1,126
Corporate and Eliminations	**(476)**	**(424)**	**(253)**	**(397)**	(369)	(355)	(362)	(213)
Total gross revenues and marketing and other	**5,534**	**4,713**	**4,351**	**4,348**	3,865	3,520	3,261	2,578
Net earnings (loss)								
Upstream								
Exploration and Production	**170**	**28**	**(67)**	**43**	198	63	(228)	(250)
Infrastructure and Marketing	**(27)**	**10**	**33**	**70**	18	1,306	35	(51)
Downstream								
Upgrading	**48**	**9**	**5**	**48**	32	27	58	58
Canadian Refined Products	**39**	**38**	**12**	**15**	8	55	36	11
U.S. Refining and Marketing	**129**	**114**	**12**	**(21)**	19	(16)	61	(7)
Corporate and Eliminations	**313**	**(63)**	**(88)**	**(84)**	(89)	(45)	(158)	(219)
Net earnings (loss)	**672**	**136**	**(93)**	**71**	186	1,390	(196)	(458)
Per share – Basic	**0.66**	**0.13**	**(0.10)**	**0.06**	0.19	1.37	(0.20)	(0.47)
Per share – Diluted	**0.66**	**0.13**	**(0.10)**	**0.06**	0.19	1.37	(0.20)	(0.47)
Adjusted net earnings (loss)[2]	**665**	**136**	**10**	**71**	(6)	(100)	(91)	(458)
Funds from operations[2]	**1,039**	**891**	**715**	**661**	662	619	505	412
Per share – Basic	**1.03**	**0.89**	**0.71**	**0.66**	0.66	0.62	0.50	0.41
Per share – Diluted	**1.03**	**0.89**	**0.71**	**0.66**	0.66	0.62	0.50	0.41
U.S./Canadian dollar exchange rate (US$)	**0.786**	**0.799**	**0.744**	**0.756**	0.750	0.766	0.776	0.728
Exploration and Production								
Daily production, before royalties								
Crude oil & NGL production *(mbbls/day)*								
Light & Medium crude oil	**46.6**	**42.7**	**56.0**	**60.7**	54.9	47.6	69.4	80.9
NGL[3]	**21.4**	**19.3**	**17.2**	**14.2**	15.9	13.4	12.8	14.0
Heavy crude oil	**42.3**	**44.1**	**43.1**	**48.0**	48.4	49.5	57.5	61.5
Bitumen	**120.9**	**117.7**	**117.4**	**120.6**	115.3	103.6	88.0	81.8
Total crude oil & NGL production *(mbbls/day)*	**231.2**	**223.8**	**233.7**	**243.5**	234.5	214.1	227.7	238.2
Natural gas *(mmcf/day)*[3]	**534.9**	**563.4**	**514.8**	**543.1**	555.4	521.3	528.8	618.6
Total production *(mboe/day)*	**320.4**	**317.7**	**319.5**	**334.0**	327.0	301.0	315.8	341.3
Average sales prices								
Light & Medium crude oil *($/bbl)*	**77.05**	**63.13**	**63.27**	**66.70**	64.12	54.91	56.11	39.65
NGL *($/bbl)*[7]	**51.19**	**37.83**	**38.00**	**49.64**	46.47	35.62	36.68	31.89
Heavy crude oil *($/bbl)*	**48.64**	**41.89**	**42.06**	**41.28**	36.30	35.04	34.88	18.12
Bitumen *($/bbl)*	**41.88**	**38.14**	**37.46**	**35.20**	33.80	29.53	30.95	12.83
Natural gas *($/mcf)*[3]	**5.89**	**5.25**	**5.59**	**5.35**	5.65	3.99	3.46	4.41
Operating costs *($/boe)*	**13.20**	**14.12**	**14.65**	**13.75**	13.92	15.15	13.90	13.31
Operating netbacks[3][4]								
Lloydminster Thermal *($/bbl)*[5]	**33.98**	**27.38**	**24.14**	**24.88**	22.02	19.72	24.61	10.02
Lloydminster Non-Thermal *($/boe)*[5]	**19.36**	**12.46**	**12.70**	**14.80**	11.58	11.28	15.05	0.50
Tucker Thermal *($/bbl)*[5]	**31.79**	**28.35**	**24.09**	**23.53**	21.34	20.04	26.55	5.28
Sunrise Energy Project *($/bbl)*[5]	**16.50**	**16.05**	**11.67**	**2.24**	5.42	0.90	(26.52)	(53.29)
Western Canada – Crude Oil *($/bbl)*[5]	**12.99**	**3.64**	**12.03**	**19.18**	5.06	11.37	18.95	(1.94)
Western Canada – NGL & natural gas *($/mcf)*[6]	**0.15**	**0.12**	**1.01**	**1.05**	1.36	0.45	(0.56)	0.36
Atlantic – Light Oil *($/bbl)*[5]	**59.00**	**35.86**	**42.08**	**44.39**	40.49	22.83	28.55	27.82
Asia Pacific – Light Oil, NGL & natural gas *($/boe)*[3][5]	**65.31**	**61.81**	**61.90**	**64.43**	61.09	47.77	59.21	61.11
Total *($/boe)*[5]	**30.00**	**23.25**	**23.53**	**24.17**	22.32	15.70	17.30	9.68

Segmented Operational Information (continued)	2017 Q4	2017 Q3	2017 Q2	2017 Q1	2016 Q4	2016 Q3	2016 Q2	2016 Q1
Upgrading								
Synthetic crude oil sales *(mbbls/day)*	**56.5**	**58.2**	**30.3**	**54.1**	50.0	53.3	59.8	57.7
Total sales *(mbbls/day)*	**77.9**	**79.4**	**40.3**	**76.2**	66.9	69.7	76.5	78.3
Upgrading differential *($/bbl)*	**21.46**	**13.60**	**18.70**	**20.88**	20.36	19.45	20.85	22.23
Canadian Refined Products								
Fuel sales *(millions of litres/day)*	**8.0**	**8.1**	**6.5**	**6.4**	6.6	6.8	6.8	6.2
Refinery throughput								
Lloydminster Refinery *(mbbls/day)*	**30.1**	**30.0**	**19.5**	**28.0**	28.4	26.7	28.2	28.0
Prince George Refinery *(mbbls/day)*	**11.3**	**11.9**	**9.7**	**11.8**	11.8	9.7	5.1	11.0
U.S. Refining and Marketing								
Refinery throughput								
Lima Refinery *(mbbls/day)*	**164.5**	**178.3**	**174.1**	**172.0**	165.1	155.6	103.9	127.5
BP-Husky Toledo Refinery *(mbbls/day)*	**81.0**	**77.3**	**71.1**	**77.0**	78.8	58.4	41.2	69.4
Superior Refinery *(mbbls/day)*[7]	**22.0**	**—**	**—**	**—**	—	—	—	—

(1) *During the third quarter of 2017, the Company corrected certain intrasegment sales eliminations. Gross revenues and purchases of crude oil and products have been recast for the first two quarters of 2017. There was no impact on net earnings.*

(2) *Adjusted net earnings (loss) and funds from operations are non-GAAP measures. Refer to Section 9.3 for a reconciliation to the GAAP measures.*

(3) *Reported production volumes and associated per unit values include Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for financial statement purposes.*

(4) *Operating netback is a non-GAAP measure. Refer to Section 9.3.*

(5) *Includes associated co-products converted to boe.*

(6) *Includes associated co-products converted to mcfge.*

(7) *The Superior Refinery was acquired on November 8, 2017.*

Significant Items Impacting Gross Revenues, Net Earnings (Loss) and Funds from Operations

Variations in the Company's gross revenues, net earnings (loss) and funds from operations (non-GAAP measure) are primarily driven by changes in production volumes, commodity prices, commodity price differentials, refining crack spreads, foreign exchange rates and planned turnarounds. Stronger crude oil and North American natural gas prices throughout 2017, resulted in an increase to Company's gross revenues, net earnings and funds from operations (non-GAAP measure). Other significant items which impacted gross revenues, net earnings and funds from operations (non-GAAP measure) over the last eight quarters include:

2017

Q4:

- On November 8, 2017, the Company completed the purchase of the Superior Refinery, a 50,000 bbls/day permitted capacity facility located in Superior, Wisconsin, U.S., from Calumet for $670 million (US$527 million) in cash, which includes $108 million (US$85 million) of working capital, subject to final adjustments.
- At the Tucker Thermal Project, drilling of the new 15-well pad was completed in the second quarter and steaming commenced in the fourth quarter of 2017.
- At the Sunrise Energy Project production continued to ramp up and the 14 previously drilled well pairs were tied in and are producing.
- Production from 10 wells of the 16-well program in the Ansell and Kakwa areas was achieved. Due to improved operating efficiencies, drilling times were reduced by 30 percent during 2017, contributing to a 22 percent reduction in per-well drilling costs.
- At Karr in the Montney formation, two wells were drilled in the third quarter and production was achieved in the fourth quarter.
- Production continued to ramp up at the BD Project. The first lifting of NGL occurred mid-October.
- An additional infill well was completed at the main White Rose field, which was tied back to the *SeaRose* FPSO, providing for improved capital efficiencies.
- The sale of select assets in Western Canada to third parties was completed, representing approximately 17,600 boe/day for gross proceeds of approximately $65 million resulting in an after-tax gain of $9 million.
- The recognition of $436 million in deferred tax recovery related to the reduction in the U.S. Federal corporate tax rate that will take effect in 2018.

Q3:

- First production was achieved at the BD Project in the Madura Strait. NGL were produced and stored on the FPSO.
- Nine wells of a 16-well program in the Ansell and Kakwa areas were completed by the third quarter.
- Production from one well at Wembley in the Montney formation commenced.
- At South White Rose, an oil production well and a supporting water injection well were completed.
- The consolidation of a single expanded truck transport network of approximately 160 sites was completed during the quarter.

Q2:
- The Company recognized an after-tax impairment expense of $123 million related to crude oil and natural gas assets located in Western Canada in the Upstream Exploration and Production segment. The impairment charges were the result of changes in the development plans and reinforced by market transactions.
- Lloydminster Upgrader and Lloydminster Asphalt Refinery throughput and sales volumes were lower due to major planned turnarounds at the Lloydminster Upgrader and Lloydminster Asphalt Refinery.
- The sale of select assets in Western Canada to third parties was completed, representing approximately 2,600 boe/day for gross proceeds of approximately $123 million, resulting in an after-tax gain of $23 million.

Q1:
- First oil was achieved at the Tucker Thermal Project's new eight-well pad.
- First oil was achieved from a North Amethyst infill well.

2016
Q4:
- Insurance recoveries of $176 million were accrued for business interruption and property damage associated with a fire that damaged the Company's isocracker unit at Lima during the first quarter of 2015. As at December 31, 2016, the Company had recorded a total of $411 million in insurance recoveries.
- After-tax property, plant and equipment net impairment reversal charges of $202 million were recognized and related to crude oil and natural gas assets located in Western Canada. The impairment reversal was due to an acceleration of forecasted production and revised operational economics, based on recent production performance and market transactions. In addition, the Company recorded an exploration and evaluation land after-tax write-down of $41 million primarily related to oil sands assets.
- The sale of select assets in southern Alberta was completed representing approximately 4,700 boe/day for gross proceeds of $24 million and after-tax gains of $37 million.
- An additional well was brought into production at the South White Rose drill centre.

Q3:
- The Company completed the sale of 65 percent of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan for gross proceeds of $1.69 billion in cash and an after-tax gain of $1.32 billion. The assets included approximately 1,900 kilometres of pipeline in the Lloydminster region, 4.1 mmbbls of storage capacity at Hardisty and Lloydminster and other ancillary assets. The assets are held by a newly-formed limited partnership, of which the Company owns 35 percent, PAH owns 48.75 percent and CKI owns 16.25 percent.
- The sale of several packages was completed for select legacy Western Canada crude and natural gas assets in Saskatchewan and Alberta representing approximately 5,000 boe/day for total gross proceeds of approximately $299 million, resulting in an after-tax gain of $167 million.
- The Company's China subsidiary signed a Heads of Agreement ("HOA") with CNOOC and relevant companies for the price adjustment of natural gas from the Liwan 3-1 and Liuhua 34-2 fields to set the price at Cdn. $12.50- Cdn. $15.00 per mcf at the exchange rates existing in the third quarter of 2016. Gross take-or-pay volumes from the fields remained unchanged in the range of 300-330 mmcf/day. Liquids production, net to Husky, was also expected to remain in the range of 5,000 - 6,000 bbls/day. The price adjustment under the HOA is effective as of November 20, 2015, and the settlement of outstanding payment was calculated from that date.
- First production was achieved at the North Amethyst Hibernia formation well.
- First oil was achieved at the 4,500 bbls/day Edam West heavy oil thermal development.

Q2:

- U.S. Refining and Marketing throughput and sales volumes were lower due to major planned turnarounds at both the Lima and BP-Husky Toledo Refineries.
- Prince George Refinery gross margins were lower due to a planned turnaround.
- Demand for natural gas in North America was lower due to unseasonably mild weather conditions coupled with a temporary decline in natural gas demand from Canadian oil sands operations due to the wildfires in the Fort McMurray region of Alberta.
- The Company recorded an exploration and evaluation land after-tax write-down of $22 million relating to two exploration wells drilled in the Flemish Pass Basin which did not encounter economic quantities of hydrocarbons.
- The sale of several packages of select legacy Western Canada crude oil and natural gas assets in Saskatchewan and Alberta was completed, representing approximately 20,500 boe/day for total gross proceeds of approximately $791 million. As a part of one of the transactions, the Company obtained interests in lands with thermal development potential in the Lloydminster region. The Company recorded an after-tax loss of $184 million for the sale.
- The sale of royalty interests was completed representing approximately 1,700 boe/day of Western Canada production. Proceeds included $165 million in cash and other considerations, including the transfer to the Company of royalty and working interests in select heavy oil properties in the Lloydminster area. The Company recorded an after-tax gain of $119 million for the sale.
- First oil was achieved at the 10,000 bbls/day Vawn heavy oil thermal development.
- First oil was achieved at the 10,000 bbls/day Edam East heavy oil thermal development.
- First oil was achieved from the Colony formation at the Tucker Thermal Project.

Q1:

- Upgrading throughput decreased primarily due to unscheduled maintenance.

Segmented Financial Information

	Upstream								Downstream			
	Exploration and Production[1]				Infrastructure and Marketing				Upgrading			
2017 *($ millions)*	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues	**1,355**	**1,157**	**1,215**	**1,251**	**704**	**513**	**426**	**333**	**452**	**377**	**227**	**384**
Royalties	**(97)**	**(71)**	**(91)**	**(104)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Marketing and other	**—**	**—**	**—**	**—**	**(71)**	**(4)**	**(1)**	**36**	**—**	**—**	**—**	**—**
Revenues, net of royalties	**1,258**	**1,086**	**1,124**	**1,147**	**633**	**509**	**425**	**369**	**452**	**377**	**227**	**384**
Expenses												
Purchases of crude oil and products	**(1)**	**—**	**1**	**—**	**657**	**495**	**408**	**295**	**304**	**287**	**144**	**248**
Production, operating and transportation expenses	**390**	**413**	**430**	**417**	**7**	**1**	**2**	**3**	**49**	**45**	**54**	**49**
Selling, general and administrative expenses	**84**	**63**	**61**	**57**	**1**	**1**	**1**	**1**	**3**	**1**	**3**	**2**
Depletion, depreciation, amortization and impairment	**471**	**514**	**705**	**547**	**—**	**1**	**1**	**—**	**30**	**31**	**19**	**19**
Exploration and evaluation expenses	**38**	**31**	**56**	**21**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Loss (gain) on sale of assets	**(13)**	**3**	**(33)**	**1**	**—**	**—**	**—**	**1**	**—**	**—**	**—**	**—**
Other – net	**37**	**(7)**	**(39)**	**15**	**(6)**	**10**	**(9)**	**(3)**	**—**	**—**	**—**	**—**
	1,006	**1,017**	**1,181**	**1,058**	**659**	**508**	**403**	**297**	**386**	**364**	**220**	**318**
Earnings from operating activities	**252**	**69**	**(57)**	**89**	**(26)**	**1**	**22**	**72**	**66**	**13**	**7**	**66**
Share of equity investment gain (loss)	**13**	**(1)**	**(1)**	**1**	**(12)**	**13**	**24**	**24**	**—**	**—**	**—**	**—**
Net foreign exchange gains (losses)	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Finance income	**1**	**2**	**1**	**1**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Finance expenses	**(33)**	**(31)**	**(35)**	**(32)**	**—**	**—**	**—**	**—**	**—**	**(1)**	**—**	**—**
	(32)	**(29)**	**(34)**	**(31)**	**—**	**—**	**—**	**—**	**—**	**(1)**	**—**	**—**
Earnings (loss) before income tax	**233**	**39**	**(92)**	**59**	**(38)**	**14**	**46**	**96**	**66**	**12**	**7**	**66**
Provisions for (recovery of) income taxes												
Current	**(8)**	**(25)**	**12**	**(13)**	**—**	**—**	**—**	**—**	**24**	**12**	**4**	**23**
Deferred	**71**	**36**	**(37)**	**29**	**(11)**	**4**	**13**	**26**	**(6)**	**(9)**	**(2)**	**(5)**
	63	**11**	**(25)**	**16**	**(11)**	**4**	**13**	**26**	**18**	**3**	**2**	**18**
Net earnings (loss)	**170**	**28**	**(67)**	**43**	**(27)**	**10**	**33**	**70**	**48**	**9**	**5**	**48**
Capital expenditures[4]	**525**	**355**	**307**	**289**	**—**	**—**	**—**	**—**	**14**	**27**	**168**	**21**
Total assets	**17,920**	**18,021**	**18,275**	**18,802**	**1,364**	**1,447**	**1,338**	**1,422**	**1,263**	**1,261**	**1,179**	**1,129**

(1) *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to Exploration and Production.*

(2) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices.*

(3) *During the third quarter of 2017, the Company corrected certain intrasegment sales eliminations. Gross revenues and purchases of crude oil and products have been recast for the first two quarters of 2017. There was no impact on net earnings.*

(4) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period. Includes Exploration and Production assets acquired through acquisition, and excludes assets acquired through corporation acquisition.*

Downstream (continued)								Corporate and Eliminations[2]				Total			
Canadian Refined Products				U.S. Refining and Marketing[3]											
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
815	802	602	568	2,755	2,292	2,135	2,173	(476)	(424)	(253)	(397)	5,605	4,717	4,352	4,312
—	—	—	—	—	—	—	—	—	—	—	—	(97)	(71)	(91)	(104)
—	—	—	—	—	—	—	—	—	—	—	—	(71)	(4)	(1)	36
815	802	602	568	2,755	2,292	2,135	2,173	(476)	(424)	(253)	(397)	5,437	4,642	4,260	4,244
647	650	477	445	2,316	1,876	1,894	1,973	(476)	(424)	(253)	(397)	3,447	2,884	2,671	2,564
66	63	67	60	151	135	137	140	—	—	—	—	663	657	690	669
19	12	11	11	4	4	3	4	121	61	63	59	232	142	142	134
28	27	27	29	90	82	93	89	28	18	17	16	647	673	862	700
—	—	—	—	—	—	—	—	—	—	—	—	38	31	56	21
—	(5)	—	—	—	—	—	—	—	—	—	—	(13)	(2)	(33)	2
(1)	—	—	—	(14)	10	(14)	(3)	(3)	12	(3)	—	13	25	(65)	9
759	747	582	545	2,547	2,107	2,113	2,203	(330)	(333)	(176)	(322)	5,027	4,410	4,323	4,099
56	55	20	23	208	185	22	(30)	(146)	(91)	(77)	(75)	410	232	(63)	145
—	—	—	—	—	—	—	—	—	—	—	—	1	12	23	25
—	—	—	—	—	—	—	—	5	2	(11)	(2)	5	2	(11)	(2)
—	—	—	—	—	—	—	—	10	9	8	5	11	11	9	6
(3)	(3)	(3)	(3)	(4)	(4)	(3)	(3)	(59)	(58)	(62)	(55)	(99)	(97)	(103)	(93)
(3)	(3)	(3)	(3)	(4)	(4)	(3)	(3)	(44)	(47)	(65)	(52)	(83)	(84)	(105)	(89)
53	52	17	20	204	181	19	(33)	(190)	(138)	(142)	(127)	328	160	(145)	81
18	11	6	10	(4)	5	1	—	(14)	(31)	(18)	(16)	16	(28)	5	4
(4)	3	(1)	(5)	79	62	6	(12)	(489)	(44)	(36)	(27)	(360)	52	(57)	6
14	14	5	5	75	67	7	(12)	(503)	(75)	(54)	(43)	(344)	24	(52)	10
39	38	12	15	129	114	12	(21)	313	(63)	(88)	(84)	672	136	(93)	71
25	14	37	11	122	88	52	51	59	27	16	12	745	511	580	384
1,548	1,533	1,516	1,503	7,580	6,676	6,769	7,035	3,252	3,219	3,295	3,003	32,927	32,157	32,372	32,894

2016 ($ millions)	Upstream								Downstream			
	Exploration and Production[(1)]				Infrastructure and Marketing				Upgrading			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues	1,215	941	1,044	836	195	275	270	215	340	334	369	281
Royalties	(105)	(56)	(90)	(54)	—	—	—	—	—	—	—	—
Marketing and other	—	—	—	—	(9)	5	18	(102)	—	—	—	—
Revenues, net of royalties	1,110	885	954	782	186	280	288	113	340	334	369	281
Expenses												
Purchases of crude oil and products	—	6	14	12	186	273	227	171	224	225	222	137
Production, operating and transportation expenses	438	429	442	451	3	2	7	8	49	43	40	36
Selling, general and administrative expenses	81	57	52	42	2	1	1	1	2	—	1	1
Depletion, depreciation, amortization and impairment	237	474	542	562	—	1	6	6	21	27	27	28
Exploration and evaluation expenses	78	17	76	17	—	—	—	—	—	—	—	—
Loss (gain) on sale of assets	(55)	(236)	96	2	3	(1,442)	—	—	—	—	—	—
Other – net	29	18	9	(2)	4	(3)	(1)	(3)	—	—	(1)	—
	808	765	1,231	1,084	198	(1,168)	240	183	296	295	289	202
Earnings from operating activities	302	120	(277)	(302)	(12)	1,448	48	(70)	44	39	80	79
Share of equity investment gain (loss)	2	(1)	(1)	(1)	36	(20)	—	—	—	—	—	—
Net foreign exchange gains (losses)	—	—	—	—	—	—	—	—	—	—	—	—
Finance income	2	3	—	—	—	—	—	—	—	—	—	—
Finance expenses	(34)	(35)	(36)	(40)	—	—	—	—	—	(1)	—	—
	(32)	(32)	(36)	(40)	—	—	—	—	—	(1)	—	—
Earnings (loss) before income taxes	272	87	(314)	(343)	24	1,428	48	(70)	44	38	80	79
Provisions for (recovery of) income taxes												
Current	12	(9)	6	(109)	—	—	—	—	—	—	—	—
Deferred	62	33	(92)	16	6	122	13	(19)	12	11	22	21
	74	24	(86)	(93)	6	122	13	(19)	12	11	22	21
Net earnings (loss)	198	63	(228)	(250)	18	1,306	35	(51)	32	27	58	58
Capital expenditures[(3)(4)]	274	173	250	175	3	(5)	24	32	19	13	13	6
Total assets	19,098	18,654	19,008	20,454	1,582	1,407	1,732	1,647	1,076	1,082	1,151	1,131

(1) *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to Exploration and Production.*

(2) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices.*

(3) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*

Downstream (continued)								Corporate and Eliminations[2]				Total			
Canadian Refined Products				U.S. Refining and Marketing											
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
603	678	585	435	1,890	1,642	1,337	1,126	(369)	(355)	(362)	(213)	3,874	3,515	3,243	2,680
—	—	—	—	—	—	—	—	—	—	—	—	(105)	(56)	(90)	(54)
—	—	—	—	—	—	—	—	—	—	—	—	(9)	5	18	(102)
603	678	585	435	1,890	1,642	1,337	1,126	(369)	(355)	(362)	(213)	3,760	3,464	3,171	2,524
475	516	440	339	1,617	1,448	1,083	1,040	(369)	(355)	(362)	(213)	2,133	2,113	1,624	1,486
66	62	64	49	144	127	127	137	—	—	—	—	700	663	680	681
23	6	7	7	4	3	3	3	63	39	82	63	175	106	146	117
27	26	25	24	96	88	77	81	24	22	20	21	405	638	697	722
—	—	—	—	—	—	—	—	—	—	—	—	78	17	76	17
—	(2)	(1)	—	—	—	—	—	—	—	—	—	(52)	(1,680)	95	2
(1)	(8)	—	(1)	(1)	—	(50)	(125)	(4)	(17)	65	66	27	(10)	22	(65)
590	600	535	418	1,860	1,666	1,240	1,136	(286)	(311)	(195)	(63)	3,466	1,847	3,340	2,960
13	78	50	17	30	(24)	97	(10)	(83)	(44)	(167)	(150)	294	1,617	(169)	(436)
—	—	—	—	—	—	—	—	—	—	—	—	38	(21)	(1)	(1)
—	—	—	—	—	—	—	—	8	1	(9)	13	8	1	(9)	13
—	—	—	—	—	—	—	—	5	2	—	5	7	5	—	5
(2)	(2)	(1)	(2)	(1)	—	(1)	(1)	(63)	(60)	(58)	(64)	(100)	(98)	(96)	(107)
(2)	(2)	(1)	(2)	(1)	—	(1)	(1)	(50)	(57)	(67)	(46)	(85)	(92)	(105)	(89)
11	76	49	15	29	(24)	96	(11)	(133)	(101)	(234)	(196)	247	1,504	(275)	(526)
—	—	—	—	—	—	—	—	4	24	23	48	16	15	29	(61)
3	21	13	4	10	(8)	35	(4)	(48)	(80)	(99)	(25)	45	99	(108)	(7)
3	21	13	4	10	(8)	35	(4)	(44)	(56)	(76)	23	61	114	(79)	(68)
8	55	36	11	19	(16)	61	(7)	(89)	(45)	(158)	(219)	186	1,390	(196)	(458)
12	3	29	8	67	107	267	182	16	18	12	7	391	309	595	410
1,410	1,419	1,458	1,399	7,017	6,822	6,866	6,444	2,077	2,179	763	821	32,260	31,563	30,978	31,896